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April 8, 1992

Mr. Charles W. Ballentine, Executive Director
The Public Service Commission of South Carolina
P. O. Drawer 11649
Columbia, South Carolina 29211

Re: Integrated Resource Plan
Docket No. 92-208-E

Dear Mr. Ballentine:

In Docket No. 87-223-E the Commission issued Order No. 91-1002 which directed the electric utilities to file an Integrated Resource Plan prior to April 30, 1992.

Enclosed for filing are 15 copies of Duke Power Company's 1992 Integrated Resource Plan.

Very truly yours,

W Larry Porter

William Larry Porter
Associate General Counsel

Karol P. Mack
Senior Attorney

WLP/fhb
Encl.

cc: Mr. Steven W. Hamm with 1 encl.

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Integrated Resource Plan
1992

VOLUME I
EXECUTIVE SUMMARY

DUKE POWER COMPANY

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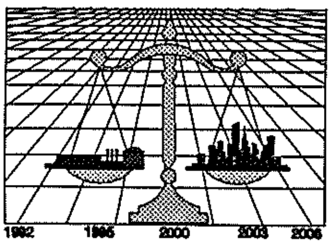
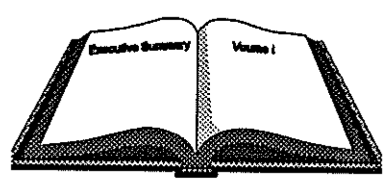
Executive Summary
The 1992 Integrated Resource Plan
Duke Power Company

1 Introduction



1.1 Purpose: The purpose of Duke Power's 1992 Integrated Resource Plan is to analyze all current and potential sources and uses of power over the next 15 years. The final plan -- which is derived from a sophisticated integrated analysis -- results in an optimal long-term combination of power-supply options and energy-efficient power-demand options that will serve as a guide for resource planning and ensure adequate and reliable electricity in an environmentally responsible manner to Duke's customers through cost-effective "Power Management."

1.2 Executive Summary Design : While, of necessity, the other three more-technical volumes of this report provide complex, sophisticated and detailed analyses and descriptions, this Executive Summary is intended to serve as an overview of both the plan and the process used to create the plan. In preparing the summary, we also felt it would prove helpful and useful to cast this executive summary in non-technical language and provide the following quick overview of our concept of power management.

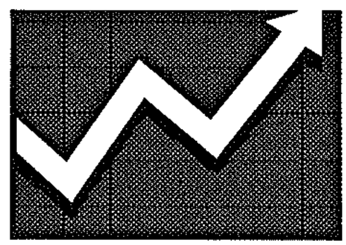


1.3 Overview of Power Management

1.3.1 Responsible Power Management: To Duke, responsible power management is the art and science of building an array of power-generating sources called supply-side resources (e.g., hydroelectric power stations, nuclear power stations, coal-burning power stations, and combustion turbines) and the distribution facilities (lines, poles and transformers) to provide industrial customers (factories and plants), commercial customers (offices and stores) and residential customers (homes) -- which together comprise what we term the demand side -- with safe, reliable and ample electric power. Today, a key focus of responsible power management is to concentrate on ways to help customers better manage their use of power (demand-side management) effectively with prudent care of the environment.

> **Duke's Focus**
>
> **Help Customers better manage their use of power**

1.3.2 Management of Fluctuating Demand: America's advanced economy -- and especially Duke's customer base throughout the Piedmont region of North and South Carolina -- leads to significant differences between the peaks and valleys of power demand. Therefore, Duke's Integrated Resource Plan (IRP) must, of necessity, address a widely fluctuating hourly demand for power in our service area.

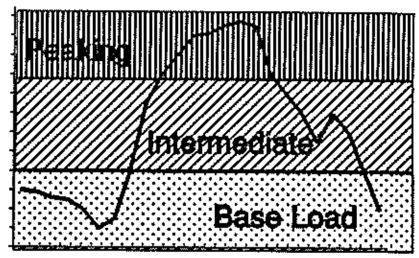


1.3.3 Description of Key Variables: The following descriptions are intended to provide a general appreciation of the hourly, daily and annual-demand variables to which Duke's Integrated Resource Plan must respond over the next 15 years:

- **Peaks:** On the one hand, Duke must economically meet the peak-power demands of a particularly hot weekday in summer with all factories running full tilt, offices at full operation and with millions of air conditioners cooling at maximum output.

- **Valleys:** On the other hand, Duke must be prepared to economically throttle back the supply of power for a 70-degree spring Sunday with few factories and offices in operation and most air conditioners shut down.

- **Norms:** And, quite obviously, Duke must be prepared to provide safe and low-cost power at all levels and conditions between the peaks and the valleys.

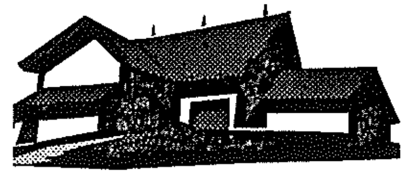


- **Reserves:** Because all generating equipment cannot be made constantly available (e.g: equipment needs down-time for maintenance, overhauls etc.), a reserve capability must be maintained to ensure system reliability. Duke currently feels -- and regulators have agreed -- that a minimum reserve of 20 percent over the peak demand is appropriate.

1.3.4 Accent on Demand-side Management:

- **Early Approach:** Historically, electric utilities have concentrated on making sure there were sufficient supply-side resources (power plants) to meet all their current and potential customers' demand for reliable power. The utility would then charge customers the cost of that power plus a reasonable return to the shareholders who, after all, provided the capital to build the generators and the system that made it available.

- **Today's Focus:** Today modern and responsible electric utilities like Duke Power are also focused on helping customers find ways to fulfill their power needs using energy more efficiently (e.g.: high-efficiency lighting and insulation) and to use that power at times that tend to smooth power demands (e.g.: off-peak use of power). A second area of focus is to encourage customers to recognize the need for individual power-control or interruption devices (e.g.: load-control switches) that allow the utility to selectively interrupt power to specific end uses (such as hot-water heating and air conditioning) of individual customers based on an agreement with each customer. The benefit of the power interruption options lies in the fact that, through selective power interruption capability, both Duke and its customers do not have to pay to maintain as great an array of reserve generation facilities for unusual peaks in power usage. Without question, however, Duke's focus for the future continues to be on helping customers use power more efficiently.

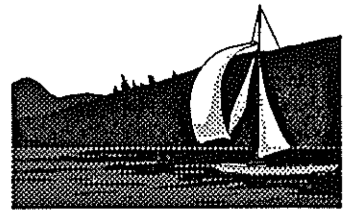


1.3.5 The Irony of Demand-Side Management: It is perhaps ironic, but nevertheless represents a sound and responsible business practice, that Duke invests thousands of hours of valuable time as well as significant amounts of research and development funds and resources to find ways for customers to use less of Duke's product. As a public utility, Duke recognizes a stewardship responsibility -- not only to provide reliable, safe, economical and environmentally responsible power to customers, but to help customers find ways to manage the area's consumption -- not only of supplying today's power, but tomorrow's need for power as well.

Duke's Responsibility

Power Stewardship

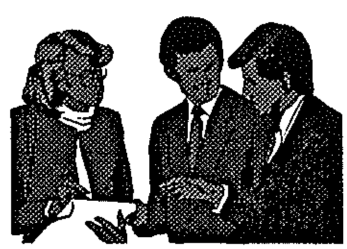
1.3.6 Environmentally Sound Use of Power:



Fundamental to Duke's responsibility to consumers and neighbors is the need, not only to provide the power requirements of customers, but also to find new ways of generating, distributing and using power in the future in an environmentally responsible manner. Fortunately -- as this plan and process will show -- due to the responsible leadership of successive generations of management, Duke is not only consistently conducting its own operations in environmentally responsible ways, but it is helping customers to manage their consumption of power, which inherently moderates the growth rate of emissions.

1.4 Duke's Relationship with the State:

- **Formal Plan submission:** While, historically, Duke has followed an informal integrated planning process for meeting customers' energy needs, the state governments of North Carolina and South Carolina -- to which Duke, as a regulated public utility, is responsible -- have increasingly required more formal plans be submitted to state regulatory officials for review and approval. This 1992 Integrated Resource Plan represents the second plan submitted to state regulatory agencies.



- **Relationship between Duke and the Regulators:** While there is, of course, an oversight relationship between Duke and the state regulatory agencies, Duke believes -- and our experience has confirmed -- that Duke's best interests and the State's best interests are virtually the same: to provide safe, reasonably priced power to our customers in environmentally responsible ways.

- **Early Experience:** As a matter of fact, Duke's early experience has shown that working with state regulators and responding to the concerns of interested parties in the early stages of the planning process have resulted in new ways to solve problems and to find win-win solutions to concerns as they arise.

- **Positive Cooperation:** Duke believes this plan or any plan that strives to meet the power needs of nearly 5 million people for a 15-year period will require the positive and proactive cooperation of our regulators, our customers, our contractors and developers, our employees, and our investors.

Cooperation
- Positive
- Proactive

- **Duke's Integrated Resource Planning Advisory Panel:** In response to regulatory initiatives and in order to develop public involvement in the planning process, Duke has established an Integrated Resource Planning Advisory Panel. The Panel -- which consists of nine members representing regional expertise in the areas of business, industry, education, consumer and environmental concerns -- intentionally represents a wide range of views, many of which have historically been counter to those of Duke. Later in this summary, we will discuss how the panel interacts with Duke technical experts and management representatives and how they participate in -- and contribute to -- the integrated planning process.

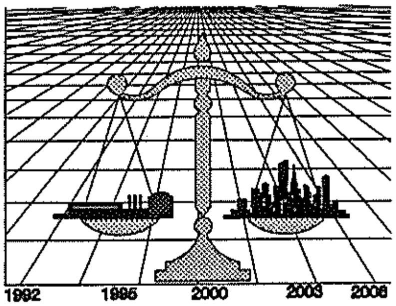
1.5 Duke's Communications Plan:

- **Awareness:** With the filing of the 1992 Integrated Resource Plan, an opportunity exists to increase the awareness of customers, employees and other groups about our total integrated resource planning effort. Focused communications about the Integrated Resource Plan will illustrate to the public we serve how Duke has attempted to identify all options for meeting their future power needs. This is especially important due to the critical need for customer participation in the plan through demand-side management programs.

- **Communications are Key:** The strategy of Duke's communications in support of integrated resource planning is to deliver messages targeted to specific audiences through largely existing and ongoing communications vehicles. Examples of these vehicles include the Duke's visitor centers and daily communications with customers and local officials, as well as various printed communications.

1.6 Summary: This section has outlined Duke's commitment to responsible power management and has highlighted the variables and environmental factors to which both the planning process and resulting Integrated Resource Plan must respond.

2 Overview and Objectives:



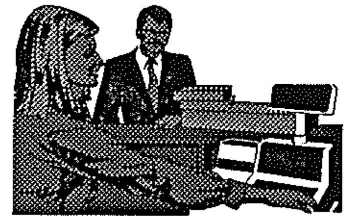
2.1 Purpose: Section 2 of both this Executive Summary and Volume II provides a brief history of Duke Power, outlines both the requirements of the regulatory authorities to which this plan must respond, and highlights the major developments that have taken place since the 1989 plan was submitted.

2.2 Duke's Responsibility to the Customer:

- **Serving the Customer's needs:** Serving the electric energy needs of the Piedmont region of the Carolinas is a towering responsibility. In addition, anticipating and preparing for the growth and changes in those needs some 15 years into the future can be at once both demanding and enlightening.

- **Duke's Historical Commitment:** Building on its long history of responsible power planning, Duke's 1992 Integrated Resource Plan (IRP) describes how the future needs of customers will be met through the year 2006 and also describes plans for a wider variety of programs to help customers manage their consumption of power.

2.3 Planning for Future Change:



Any plan that attempts to meet the responsibility of anticipating and responding to the energy needs of an entire region for over a decade and a half must be both comprehensive and flexible. Therefore Duke's planning process evaluates the broadest array of energy options. We recognize, however, that technology is changing. As a result, our planning process must be dynamic and must continually re-evaluate and reconsider all options year after year. We also recognize we must continually revise the plan as new opportunities present themselves.

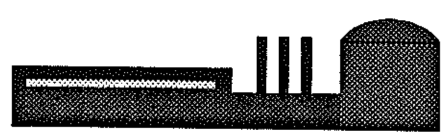
2.4 A Brief History:

To put Duke's Integrated Resource Plan (IRP) in perspective, a very brief history is appropriate:

Founded 1904

Power Supplier to The Piedmont

- **Early History:** Duke Power was founded in 1904 as a supplier of energy to the emerging textile industry in the region of North and South Carolina known as the Piedmont. The Piedmont has been -- and continues to be -- one of the nation's most industrialized regions. Today it is also an increasingly important commercial and banking center as well.

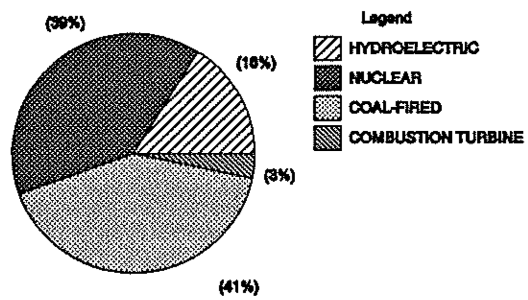


- **Changing Mix of Power Sources:** Duke originally derived its power from hydroelectric stations on the Catawba River, which flows through the heart of the Piedmont region. Over the years, these stations were gradually supplemented with coal-fired, base-load generating stations, most of which continue to operate today. In the 1970s, Duke began what became the nation's second-largest nuclear power construction program. Currently, Duke is an acknowledged world leader in safe nuclear-power generation.

2.5 Duke Power Today:

- **Size:** Today, Duke is the nation's seventh largest electric utility in terms of kilowatt-hour sales. Duke has more than 1.6 million customers in a service area that includes approximately 5 million people.

Exhibit ES 2-1: Power Sources



17,913 MEGAWATTS

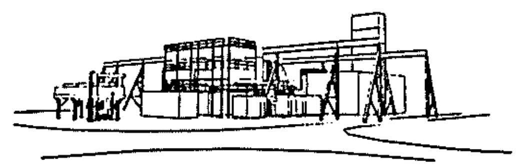
- **Supply of Power:** On the supply-side, Duke currently meets its customers' demands with the array of power sources shown in Exhibit ES: 2-1. For 17 consecutive years, through 1990, our coal-fired system has been ranked as the most efficient in the nation among investor-owned utilities by *Electric Light & Power* magazine, a respected industry source.

2.6 Major Developments Since the 1989 Plan:

- **Commercial Operation of Bad Creek Pumped Storage Hydro Station:** Bad Creek Pumped Storage Hydro Station was placed into service in 1991. with Units 1 and 2 being declared operational in May and Units 3 and 4 in September. The completion of Bad Creek adds 1,065 MW to Duke's generating capability. Located in northwestern South Carolina, the Bad Creek Station was completed approximately one year ahead of schedule, resulted in a savings of approximately $90 million.

- **Lincoln Combustion Turbine Station:** In 1989 Duke announced that a site in Lincoln County, North Carolina, had been selected for a new combustion-turbine facility to meet customer demand in the 1990s. When completed, the station will accommodate up to 16 combustion turbines with a total generating capacity of approximately 1,200 megawatts of electricity. Progress toward completion is as follows:

    - **Construction Authority:** The North Carolina Utilities Commission issued an order in March 1991 granting Duke a Certificate of Convenience and Necessity to build the station. Following that, in December 1991, Duke updated its 1991 Short-Term Action Plan calling for the first four combustion turbines to become operational in 1995.



    - **Air Quality Authority**: In December 1991, Duke was issued a final air-quality permit by the North Carolina Division of Environmental Management. The permit will allow Duke to build the units as they are needed.

- **The Clean Air Act:** Title IV of The Clean Air Act Amendments of 1990 require electric utilities to reduce aggregate annual emissions of sulfur dioxide by 10 million tons and nitrogen oxide by 2 million tons by the year 2000. These major requirements are being phased in over two periods:

  - **Phase I Compliance:** The first phase begins January 1, 1995. Duke currently meets all requirements of Phase I and will not have to implement changes until compliance with Phase II requirements becomes necessary.

    > PHASE I
    > Compliance
    > Duke Meets All Requirements

  - **Phase II Compliance:** The second phase begins January 1, 2000. Duke is currently working on a detailed compliance plan that must be filed with and approved by the Environmental Protection Agency by 1995 and implemented by the year 2000. Based on a preliminary compliance plan, the estimated costs to comply with Phase II of the requirements are expected to be approximately $1 billion in capital expenditures and approximately $81 million annually in operating and maintenance expenses. These costs are stated in year-2000 dollars.

    > PHASE II
    > Compliance
    > $1 Billion

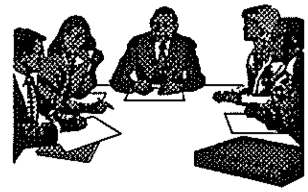
- **Duke's Position:** Duke's long history of low-emission levels through the use of low-sulfur coal, efficient operations, and the use of exceptionally clean nuclear generation, puts us in a particularly advantageous position for meeting Phase I requirements. Phase-II standards, however, will produce some real challenges. Duke is currently developing compliance plans for Phase II. Title I may require modification at some stations for NO_X control by 1996, pending issuance of state compliance plans.

Meeting Phase II requirements will present a real challenge.

- The Integrated Resource Planning Advisory Panel: As introduced in this Executive Summary, an Integrated Resource Planning Advisory Panel was formed in June 1991 and its advice and recommendations are included in Duke's planning process as follows:

- **1991 Meetings:** Three meetings were held in 1991 to orient the Panel to Duke's Integrated Resource Plan process and results. Critical issues in the process including environmental externalities and demand-side bidding were presented to the Panel. The Panel provided input which included suggestions and comments on individual demand-side programs and opinions on issues impacting the IRP process.

- **1992 Meetings:** Six meetings are scheduled during 1992 with Duke representatives in order for the Panel to provide technical guidance and recommendations on the planning process, the plan itself and ancillary issues. In early 1992, the Panel reviewed Duke's "Request for Proposal" for a demand-side bidding pilot program, a draft of the 1992 Integrated Resource Plan, and our proposed strategy on environmental externalities.

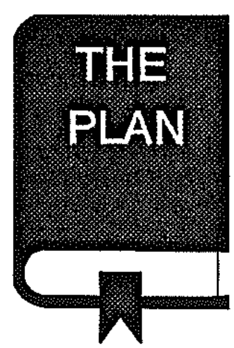


Public Involvement

- **Panel Recommendations and Reports :** Panel recommendations are documented and considered by Duke throughout the planning process. In addition, annual reports will be prepared in order to document the Panel's activities and recommendations, and Duke's response. The first annual report will be prepared following the June 1992 Panel meeting. *(Appendix II-2 contains the Panel guidelines and additional details on the meetings.)*

2.7 Forecast Comparison To Date:

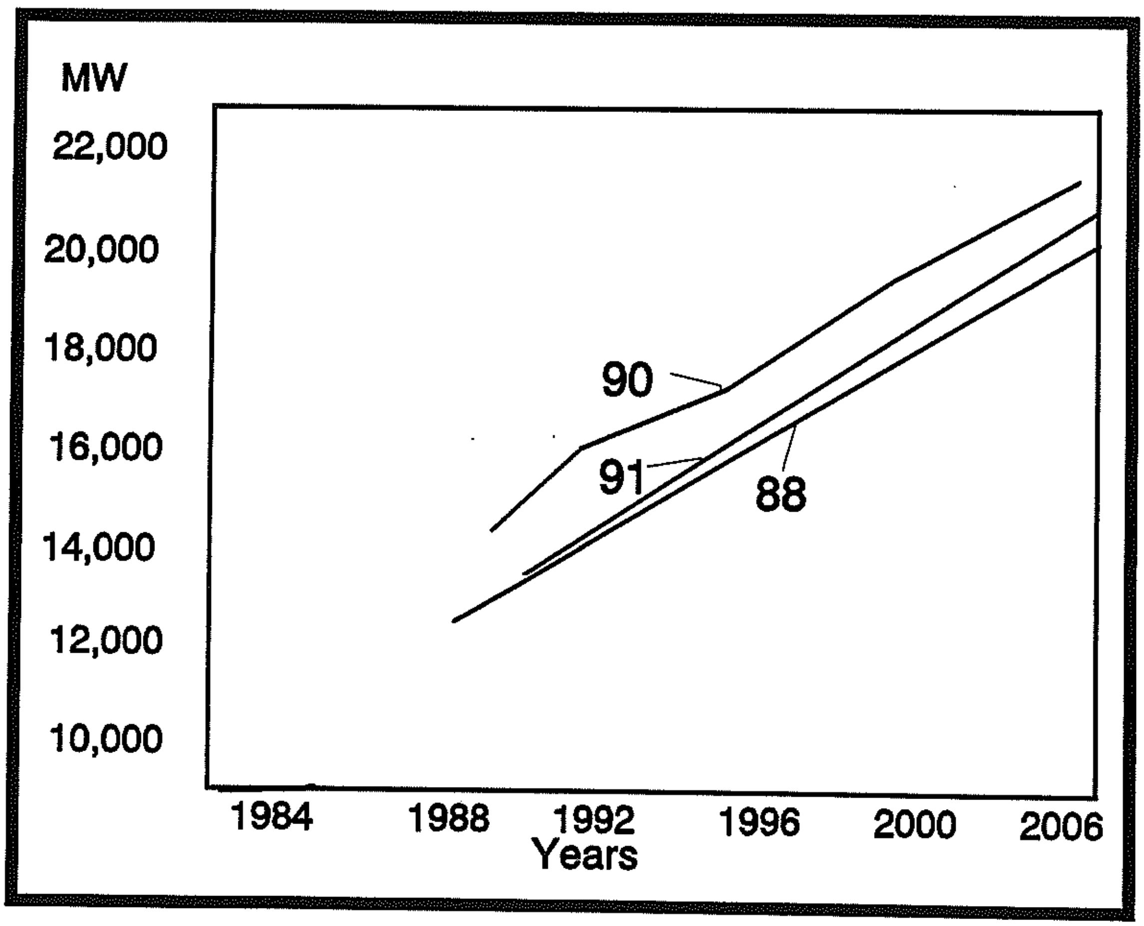
- **Recent Forecasts:** The forecast used in the 1989 Least-Cost Integrated Resource Plan was adopted in May 1988. Duke's next forecast was adopted in January 1990. This forecast was presented in both the 1990 and 1991 Short-Term Action Plans and showed an increase in summer-peak forecast in all years when compared to the May 1988 forecast. This increase was attributable



to strong and persistent growth in the summer-peak demand over earlier forecasts. The forecast used in this planning process was adopted in May 1991.

- **Graphic Summary:** A graphic comparative summary of the 1988, 1990 and 1991 summer-peak forecasts is shown in Exhibit ES 2-2. As the exhibit shows, the current 1991 forecast reveals a summer-peak reduction as compared to the 1990 forecast.

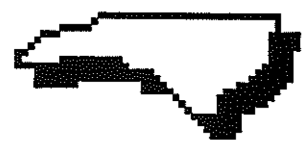
Exhibit ES 2-2: 1988, 1990 & 1991 Summer Peak Forecasts



- **Reasons for a Reduced Forecast:** There are several reasons for the lower forecast: first, the recession of 1990-1991; second, the lower-than- expected long-term rate at which new industries are moving into the service area; and, finally, the slower housing construction due to demographic trends, that are discussed in detail in Volume II, Section 5.1.

2.8 State Objectives For Integrated Resource Plans:

- **North Carolina:** The purpose of integrated resource planning as stated in the North Carolina Utilities Commission's Rules and Regulations is "...to ensure that each regulated electric utility operating in North Carolina is developing reliable projections of the long range demands for electricity in its service area and a combination of reliable resource options for meeting the anticipated demands in a cost-effective manner."



- **South Carolina:** The South Carolina Order states that "The objective of the IRP process is the development of a plan that results in the minimization of the long run total costs of the utility's overall system and produces the least cost to the consumer consistent with the availability of an adequate and reliable supply of electricity while maintaining system flexibility and considering environmental impacts."

- **Duke Power's Position:** Duke concurs with and supports the purpose and objectives of both the North and South Carolina positions, and has further expanded upon them in the following goals and objectives.

2.9 Dukes Goals and Objectives of the 1992 IRP:

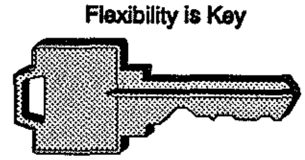
- **Goals:** The goal of Duke Power Company's 1992 Integrated Resource Plan (IRP) is to ensure -- through the use of a combination of reliable resource options, and a broad array of demand-side programs -- the anticipated power demands of Duke's service area will be met responsibly and at a reasonable cost to consumers.

> **Duke's Goals**
>
> - **Original Goal: To be a world leader in Generating Efficiency.**
> - **Expanded Goal: To also be a world leader in Consumption Efficiency.**

- **Duke's Expanding Public Responsibility:** Duke has long been known as a world leader in generating efficiency. Building on this achievement, it is fitting that Duke now pursues the expanded objective of becoming also known in the future as the company with the **most efficiently generated and consumed** electric energy in the world.

- **Flexibility is Key to Meeting Uncertainties:** Obviously, Duke's Integrated Resource Plan must allow for a broad range of anticipated and unforeseen circumstances, issues and risks in meeting the

Flexibility is Key



demands of its customers over the 15 years covered in the forecast. Therefore, wherever possible, prudent flexibility is incorporated into the plan to allow for these future uncertainties.

- **Meeting Customer Needs:**

  - **Industrial Customer Needs:** Duke's customers consist of an unusually high percentage of industrial customers who must compete on both national and international fronts. It is important, therefore, that the planning process result in electricity costs and options that will provide reliable power at a cost that will allow our industrial customers to remain nationally and internationally competitive.

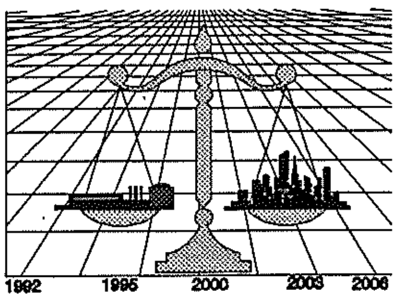
  - **Commercial and Residential Customer Needs:** Commercial and residential customers are also interested in electricity costs that are competitive as well as demand-side programs that provide savings, flexibility and reliability.

- **Meeting Environmental Concerns:** As emphasized in Section 1 of this summary and re-emphasized throughout the four volumes of this report, Duke's long-term consideration of the environment is clearly demonstrated throughout the planning process and is strongly reflected in all aspects of the 1992 plan.

- **The Legitimate Needs of the Shareholders:** The public and regulators must also recognize and support Duke's responsibility to its shareholders, who provide the capital and financial flexibility both to build Duke's system to what it has become today, and to help it meet the future needs of our service area in the long term. Regulators have the responsibility to ensure that resources are selected and implemented in such a way that economic, operational and regulatory risks are minimized and that the interests of the shareholders -- both large and small -- are protected.

2.10 Summary: As Section 2 of this Executive Summary outlines (and is more fully developed in Section 2 of Volume II), Duke's Integrated Resource Plan must consider and respond not only to state regulation, but also to a host of internal and external constituencies that each have a vested interest in its outcome. It must also respond to many other outside influences such as Duke's commitment to clean air and to the provisions of the Clean Air Act.

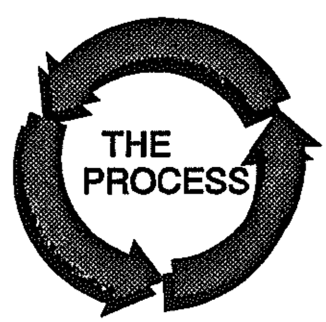
3 The Process Overview



3.1 Purpose: The purpose of the Planning Process section of this Executive Summary and of Section 3 of Volume II is to describe how the planning process was constructed, how it works, and how it develops the Integrated Resource Plan.

3.2 Differences Between The Planning Process and the Plan: To obtain a clear understanding of this document, the user needs to have a clear comprehension of the difference between Duke's planning process and its Integrated Resource Plan (IRP).

- **Duke's integrated planning process:** Basically, the planning process is the methodology or the process by which all the relevant factors -- including supply-side factors, demand-side factors, and external resources -- are considered and dealt with relative to their affects. While the following steps are described sequentially, often the assessment as well as the supply-side and demand-side analyses occurs simultaneously:



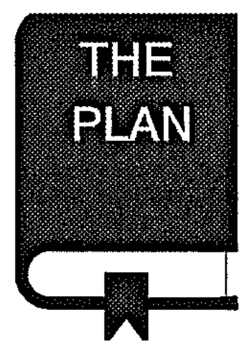
- First, we review every aspect of current operations that affects the supply and use of power.

- Second, we gather, analyze and input to our process all supply-side factors, which have been properly and prudently quantified and weighted.

- Third, we gather, analyze and input all demand-side factors, which again have been properly and prudently quantified and weighted.

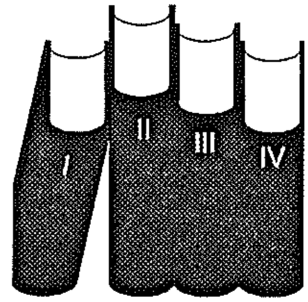
- Fourth, through an advanced and sophisticated computer-modelling process, we combine the refined supply-side and demand-side data to optimize it with current resources to meet the existing and forecasted demands of our customers. The process then creates the Integrated Resource Plan that describes how Duke will meet the needs for our service area over the next 15 years -- or until the year 2006.

3.3 Understanding the Plan: After reviewing the entire four volumes of the plan, the reader may be understandably surprised at how much attention is placed on the process. To use a simple metaphor: By inspecting each phase of construction as a home is being built, over time, the observer has a good appreciation for the final quality of the home. In the same way, by knowing and understanding the details of the planning process (from which the Integrated Resource Plan is derived) the reader gains a good appreciation of the quality of the plan and how it carefully responds to all interests.

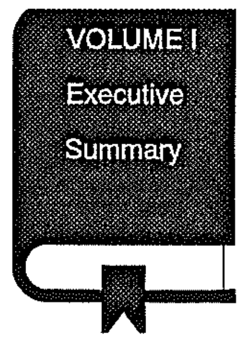


3.4 Components of the Plan:

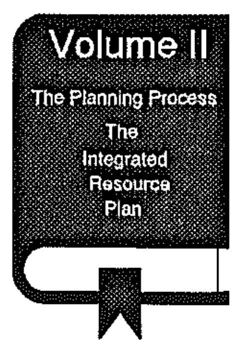
3.4.1 The Four Volumes of the Plan: The following paragraphs describe the four volumes which together comprise Duke's response to North Carolina and South Carolina utility regulatory agencies and formalizes both the planning process and the resulting Integrated Resource Plan (IRP).



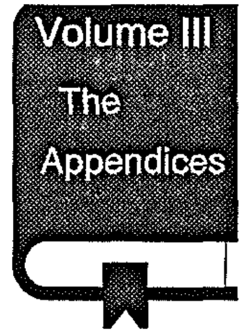
- **The First Volume (Volume I), The Executive Summary**, provides a overview of both the planning process and the resulting Integrated Resource Plan (IRP). It is intentionally broad and general in nature and attempts to present very sophisticated concepts, calculations and models in very simplified and generally understood terms -- accepting, to a degree, some loss of detail in the translation.



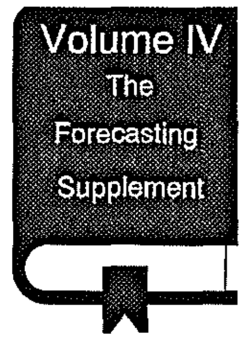
- **The Second Volume (Volume II)**, titled **The Planning Process and Integrated Resource Plan,** describes in more technical and quantified detail the stages of the planning process and the resulting plan without delving into the extremely technical levels of calculation.



- **The Third Volume (Volume III), The Appendices,** delves (as much as reasonably possible) into the detailed data, concepts and calculations supporting the analyses in Volume II for both the process and the plan.

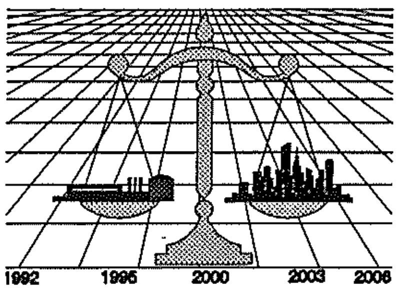


- **The Fourth Volume (Volume IV), The Forecasting Supplement,** describes and exhibits the equations used to produce the load forecast.



3.5 Summary: Once again, the reader will be somewhat disquieted by the fact that this Executive Summary seems to focus more on the process than the plan, but understanding the process will go a long way toward understanding the plan which will be fully outlined in Section 11 of this Executive Summary and of Volume II.

4 Current Operating Environment

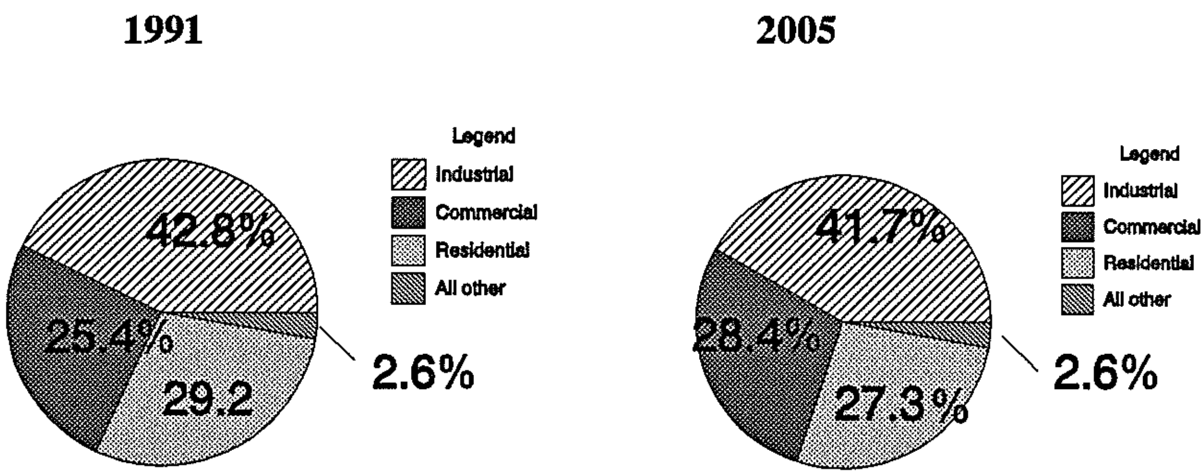


4.1 Purpose: The purpose of Section 4 of this Executive Summary (and of Section 4 of Volume II) is to provide a better understanding of Duke's current and scheduled resources as well as an appreciation of the needs and mix of customers today and in the future.

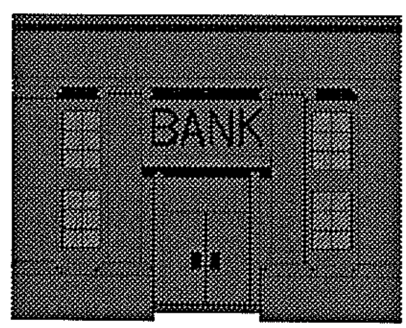
4.2 Current and Future Customer Trends: The relationship of Duke's three major customer classes -- industrial, commercial and residential -- to total sales is expected to change over the next 15 years.

- **Declining Sales to Industrial Customers:** Exhibit ES 4-1, shows a decline in the ratio of industrial sales to total sales from 1991 to 2005. Of primary importance in our service area is the textile industry which currently accounts for 43 percent of our industrial sales. However, the textile share of the industrial class has been declining as other industries -- such as electrical machinery, rubber and plastics, paper, and food products have moved into the area.

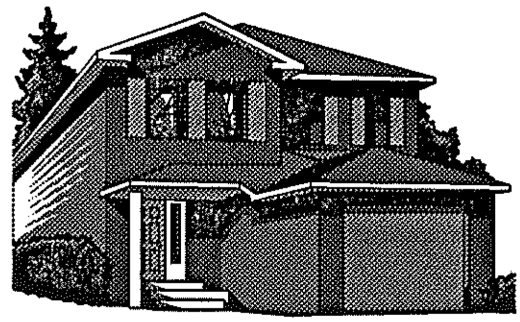
Exhibit ES 4-1:
Comparison of KWH Sales
By Customer Class



- **Growth of Commercial Customers:** The fastest growing group of customers overall is the commercial or general-service customer class. Since Charlotte has become a major banking center, many financial and professional businesses have moved into Duke's service area. Also, as new industries moved into the area, commercial-support industries followed. Although growth in the commercial class of customers has slowed due to the recession, over the long term, Duke's energy sales to commercial customers should continue to out-pace that of other customer classes.



- **Decreasing Residential Share:** The residential share of total sales is expected to decrease by two percent from current levels compared to 2005. This is primarily the result of the aging of the "baby boomers." The generations following the "boomers" will not only be fewer in number, but are expected to have less buying power.



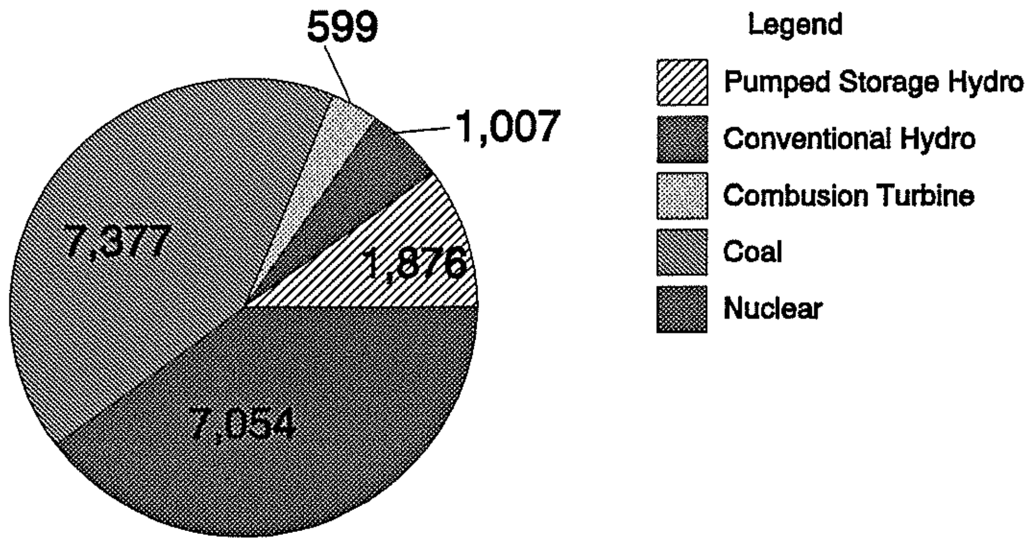
4.3 Implications of Changing Customer Mix:

- **Commercial and Industrial Implications:** Most commercial and industrial customers are heavily involved in decreasing the costs of operations. As a result, demand-side management programs that offer quick paybacks and rapid returns on their investment will be the most attractive.

- **Residential Implications:** In the residential class, programs that enhance customer-convenience at a reasonable cost continue to be the most attractive. This is especially true of the growing number of retiring residential customers who will likely face reduced buying power. These seniors will also be attracted by programs offering the quickest return on their investment.

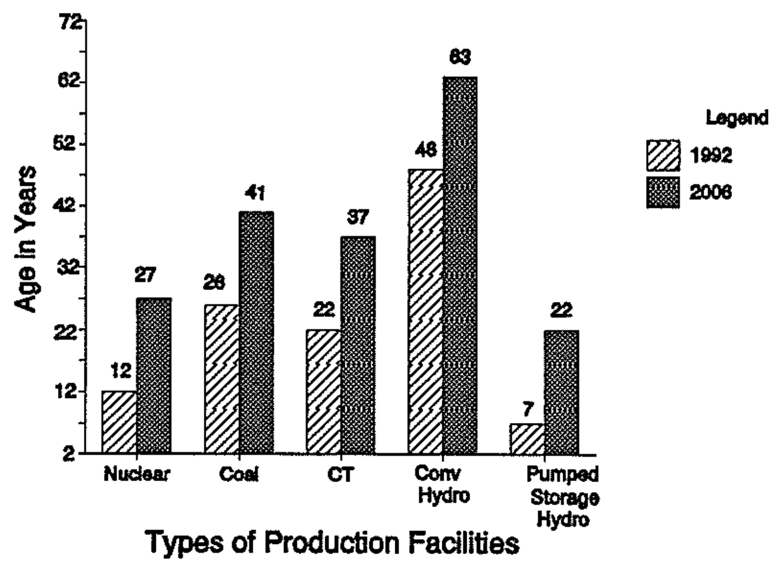
4.4 Generation Resources: Duke's total generating capacity (excluding Nantahala Power and Light) is 17,913 Megawatts (MW). This capacity is the amount of electricity available from all units under summer operating conditions. Exhibit ES 4-2 shows the sources of Duke's power generation.

Exhibit ES 4-2: Duke Power's 1992 Generating Capacity in MW



4.5 Age of Duke's Production Facilities: Exhibit ES 4-3 shows the weighted average age of Duke's production facilities in 1992 and 2006.

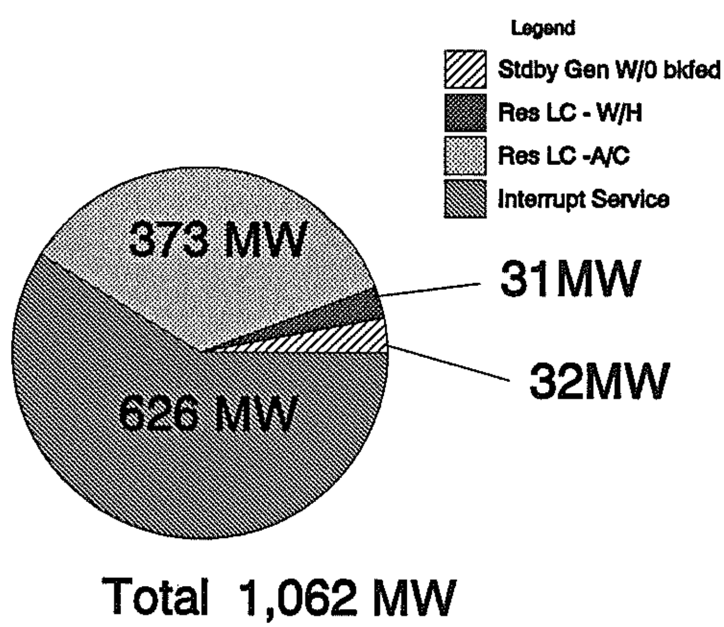
Exhibit ES 4-3: Weighted Averages of Duke's Production Facilities



- **Capacity:** Duke's Integrated Resource Plan was developed assuming that our current generation capacity will continue to be available through the year 2006 and that our operating capabilities will be the same as at the present. Consequently, there are no firm plans reflected in the Integrated Resource Plan for the retirement or replacement of existing production facilities through the year 2006. However, subsequent studies may prove such a need.

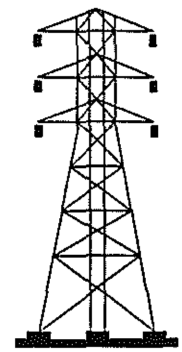
4.6 Interruptible Programs: As mentioned earlier, interruptible programs temporarily suspend full or partial service to a customer or to a specific end use (an air conditioner or a hot water heater) of that customer. Exhibit ES 4-4 shows the amount of interruptible programs available to Duke as of December 31, 1991. The megawatt values shown are those available during the summer peak period.

Exhibit ES 4-4: Interruptible Programs Reported in Megawatts



4.7 Purchased Resources:

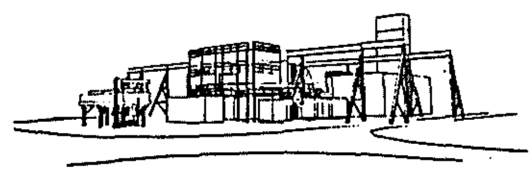
Duke has available 486 megawatts of capacity in purchased power for the year 1992. This capacity is made up of:



- 238 MW from Southeastern Power Administration.
- 200 MW from Nantahala Power and Light purchased from the Tennessee Valley Authority and scheduled to end in 1994.
- 48 MW of firm capacity from Non-Utility Generators.
- Negotiations and investigations continue for additional sources of purchased power, with none committed at the time of this report.

4.8 Scheduled Resources:

- **Lincoln Combustion Turbine Station**

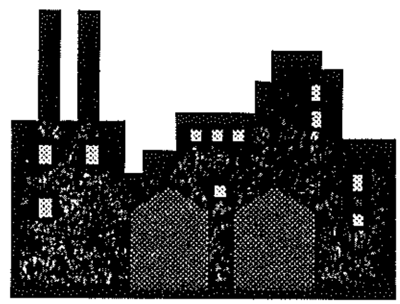


  - **Status:** On December 3, 1991, Duke filed an update to the 1991 Short Term Action Plan regarding the impact of the Integrated Resource Plan on the Lincoln Combustion Turbine Station. The current analysis continues to indicate requirements for additional peaking resources. The near-term resource mix is a combination of combustion turbines and demand-side management resources. Supply-side peaking capacity, in the form of combustion turbines, is important to the effective operation of the balance of the Duke system. Engineering for the Lincoln project is scheduled for completion at the end of the first quarter of 1992. Construction has not begun and no equipment has been released for fabrication.

- **Schedule:** The December 1991 update to the 1991 Short-Term Action Plan delayed the completion of the first Lincoln units until 1995. This change is due to the economic conditions and higher-than-anticipated effectiveness of demand-side programs. The corresponding project cost is $537 million.

- **Permits:** Duke obtained a certificate of convenience and necessity for the Lincoln project in March 1991. Duke also obtained the air-quality permit for the project in December, 1991 and is proceeding to obtain other permits.

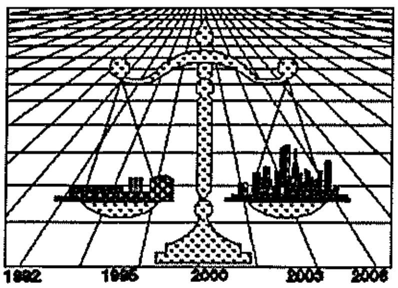
- **Plant Modernization Program:**



Coal-Fired Plants: Duke is currently pursuing a maintenance and modernization program for several of the older coal-fired units. This Plant Modernization Program (PMP) is expected to increase both the reliability and availability of these units. A significant amount of work has been completed on the remaining PMP units. In Addition, a substantial amount of the dollars budgeted to these units has already been spent.

4.9 Summary: As addressed in this Executive Summary and as described in detail in Section 4 of Volume II, the current operating environment forms the starting point from which an optimum mix of future demand-side and supply-side options can be determined.

5 Forecast



5.1 Introduction: Duke Power usually produces a 15-year forecast each year to help determine its future capacity needs, energy needs, and the resulting financial requirements. The forecast projects the peak demand for both the summer and the winter seasons and the annual energy needs for the service area.

5.2 Aggregate Forecast Results: Duke Power Company completed the current long-term forecast of peak demands and energy needs for the period 1991 through 2005 in May of 1991. This forecast is shown in Exhibit ES 5-1 on the following page.

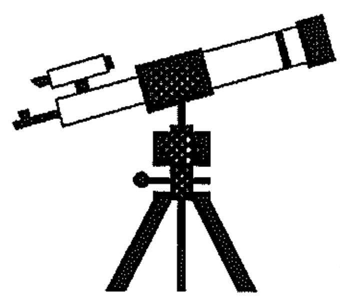


Exhibit ES 5-1: Peak Demand and Energy Forecast

	Summer Peak (MW)	Winter Peak[1] (MW)	Territorial Energy[2] (GWH)
1991	14,522	14,285	76,609
1992	14,852	14,694	78,761
1993	15,169	14,952	80,226
1994	15,549	15,317	82,046
1995	15,990	15,731	84,385
1996	16,383	16,133	86,661
1997	16,798	16,520	89,177
1998	17,248	16,943	91,406
1999	17,724	17,374	93,982
2000	18,069	17,794	96,410
2001	18,519	18,173	98,818
2002	18,949	18,573	101,062
2003	19,429	18,967	103,464
2004	19,772	19,334	105,774
2005	20,185	19,731	107,903
2006[3]	20,590		110,156

[1] The summer peak demand is for the calendar year indicated. The winter peak demand is for the winter following the summer peak demand

[2] Territorial energy is the total energy consumed within the service area

[3] 2006 is not part of the official forecast, but is used in the integration process

5.3 Forecasted Changes.

Peak Demand Growth Rates	1978/1990	1992/2006
Summer	3.1%	2.4%
Winter	3.1%	2.7%

Exhibit ES 5-2: Peak Rate Change

5.3.1 Peak Demand Growth: Shown in Exhibit ES 5-2 is the peak-demand comparative growth rates of the data shown in Exhibit ES 5-1. Even though the projected winter peak-growth rate exceeds that of the summer, Duke's forecast is expected to remain summer peaking.

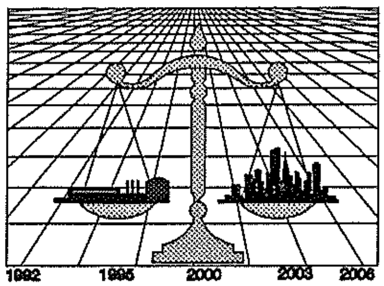
Total Energy Growth Rates	1978/1990	1992/2006
Rate of Change	2.8%	2.4%

Exhibit ES 5-3: Energy Growth Rate

5.3.2 Total Energy Growth: Exhibit ES 5-3 shows the average annual energy growth rates which are detailed in Exhibit ES 5-1. The slower rates of forecasted growth for total energy use is primarily due to slower economic growth over the forecast period.

5.4 Summary: The forecast provided in Exhibit ES 5-1 provides the projection of peak demands and total energy needs of Duke's customers for the next 15 years.

6 Demand-Side Resources:

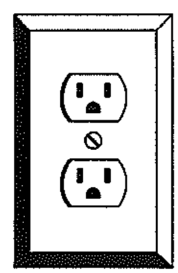


6.1 Purpose: The demand-side function of the planning process is to provide demand-side programs (both existing and revised) and new demand-side options for the planning process. These programs and options may be energy-efficient, load-shift, interruptible or environmental options.

6.2 Existing Programs and New Options: Listed in Exhibits ES 6-1 and ES 6-2 and carefully detailed in Chapter 6 of Volume II are the existing programs and new options reviewed for the planning process.

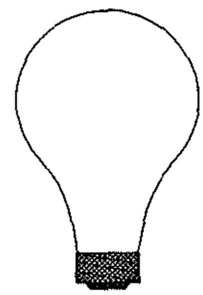
Exhibit ES 6-1: Existing Demand-Side Programs

- **Residential Load Control - Air Conditioning**
- **Residential Load Control - Water Heating**
- **Residential Controlled Off Peak Water Heating**
- **High Efficiency Heat Pump Payment**
- **High Efficiency Central Air Conditioning Payment**
- **Residential Add-On (Dual Fuel) Heat Pump**
- **High Efficiency Freezer Payment**
- **High Efficiency Refrigerator Payment**
- **Residential Insulation - New Residences (2% Discount)**
- **Residential Insulation Loan**
- **Interruptible Service**
- **Standby Generator Without Backfeed**



Note: Some existing programs were revised for the process.

Exhibit ES 6-2: New Demand-Side Options



<u>Energy Efficient Options</u>:

- **Residential Water Heating Insulating Blanket**
- **Residential High Efficiency Lighting**
- **Residential HVAC Tune-Up**
- **High Efficiency Chillers for A/C**
- **High Efficiency Unitary Equipment for A/C**
- **Non-Residential High Efficiency Indoor Lighting**
- **Motor Systems**

<u>Interruptible Options</u>:

- **Standby Generator with Backfeed**
- **Standby Generator - Capacity Improvement**
- **Standby Generator - Category C**

<u>Environmental Options</u>:

- **Metal Finishing - Recover Plating Solutions**
- **Textile - Reduction of Waste-Water Effluent**

6.3 Piloted Options: Demand-side options may have uncertainties associated with their capability to meet consumer or utility requirements. These factors consist of both technical and non-technical issues.

- Non-technical issues: Non-technical issues include customer preferences and behavior, effectiveness of program marketing/distribution efforts and program costs.

- Technical issues: Technical issues include system load-shape impacts, training for Duke personnel, and additional metering or communications equipment needed.

- **Pilots Not in the Integrated Resource Plan:** Exhibit ES 6-3 lists the ongoing piloted options that were not included in the planning process. These pilots are described at length in Appendix VI-3

Exhibit ES 6-3: Piloted Demand-Side Management Options (Not in the Current Planning Process)

- **Residential High Efficiency Ground Coupled Heat Pump**
- **Non-Residential Air Conditioning Load Shift (Cool Storage)**
- **Industrial High Efficiency Dust Collection**
- **Non-Residential Heat Treating Load Shift**
- **Non-Residential Air Conditioning Load Control**

6.4 Demand-Side Programs and Options: Exhibit ES 6-4 shows the following:

- All the demand-side options and programs that were reviewed.
- Whether each was an existing program or new option.
- If the existing program was revised.
- Whether the option was forwarded to the Updated Plan or to the integration process as a new option.
- The last column shows the type of option: Interruptible, Load Shift, Energy Efficiency or Environmental.
- And finally the chart indicates with a "#" sign the programs that were not forwarded to the integration process.
- The abbreviated name for use in other tables.

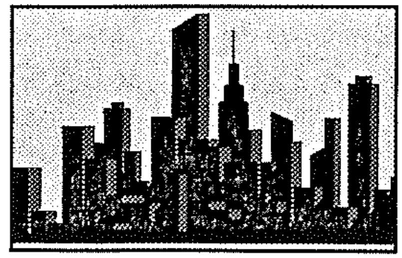
EXHIBIT ES 6-4: Program and Option Names - Disposition

Program And Option Names	Abbreviated Name	Existing	Revised	New	Forwarded To Resource Integration: Updated Plan	Forwarded To Resource Integration: New Option	Type
1) Residential Load Control - Water Heating	Res LC-W/H						
- Existing Program		XX			XX		I
- Revised Program			XX			XX	I
2) Residential Load Control - Air Conditioning	Res LC-A/C						
- Existing Program		XX			XX		I
- Revised Program			XX			XX	I
3) Residential Controlled Off Peak Water Heating							
- Existing Program	Res Off Peak W/H	XX		XX			LS
- WC submetered lower rate	Res Off Peak W/H-Submetered		XX			XX	LS
- Flat monthly payment	Res Off Peak W/H-Flat Pay		XX			XX	LS
4) High Efficiency Heat Pump Payment	HE Heat Pump-Res	XX			XX		EE
5) High Efficiency Central Air Conditioning Payment	HE Central A/C-Res	XX			XX		EE
6) Residential Add-On (Dual Fuel) Heat Pump	Res Duel Fuel HP	XX			XX		EE
7) High Efficiency Freezer Payment	HE Freezer-Res	XX			XX		EE
8) High Efficiency Refrigerator Payment	HE Refrig-Res	XX			XX		EE
9) Residential Insulation - New Residences (2% Discount)	Res Insulation New Resid	XX			XX		EE
10) Residential Insulation Loan	Res Insulation Loan	XX			XX		EE
11) Interruptible Service							
- Existing Program	IS	XX			XX		I
- Start the Additions in 1992	IS-Start in 1992		XX			XX	I
- Start the Additions in 1993	IS-Start in 1993		XX			XX	I
- Start the Additions in 1994	IS Start in 1994		XX			XX	I
- Start the Additions in 1995	IS Start in 1995		XX			XX	I
- Start the Additions in 1996	IS Start in 1996		XX			XX	I
- Start the Additions in 1998	IS Start in 1998		XX			XX	I
- Start the Additions in 2000	IS Start in 2000		XX			XX	I
- Start the Additions in 2003	IS Start in 2003		XX			XX	I
- Start the Additions in 2006	IS Start in 2006		XX			XX	I
12) Standby Generator Without Backfeed	SG W/O Backfeed	XX			XX		I
13) Residential Water Heater Insulating Blanket	Res W/H Blanket			XX		XX	EE
14) Residential HVAC Tune-Up	Res HVAC Tune-Up			XX		XX	EE
15) High Efficiency Chillers for Air Conditioning	HE Chillers for A/C			XX		XX	EE
16) High Efficiency Unitary Equipment for Air Conditioning	HE Unitary Equip for A/C			XX		XX	EE
17) Non-Residential High Efficiency Indoor Lighting							
- Electric Heating - Existing Market	Non-Res HE Ltg-El Htg-Existing			XX		XX	EE
- Electric Heating - New Market	Non-Res HE Ltg-El Htg-New			XX		XX	EE
- Fossil Heating - Existing Market	Non-Res HE Ltg-Fossil Htg-Existing			XX		XX	EE
- Fossil Heating - New Market	Non-Res HE Ltg-Fossil Htg-New			XX		XX	EE
- OPT Schedule - Existing Market	Non-Res HE Ltg-OPT-Existing			XX		XX	EE
- OPT Schedule - New Market	Non-Res HE Ltg-OPT-New			XX		XX	EE
- High Scenario Lighting - Electric Heating	Non-Res High-El Htg			XX		XX	EE
- High Scenario Lighting - Fossil Heating	Non-Res High-Fossil Htg			XX		XX	EE
- High Scenario Lighting - OPT Schedule	Non-Res High-OPT			XX		XX	EE
18) Motor Systems							
- 20% Penetration - $ 6 per Horsepower	Motor Systems-$ 6/HP			XX		XX	EE
- 50% Penetration - $12 per Horsepower	Motor Systems-$12/HP			XX		XX	EE
- 80% Penetration - $25 per Horsepower	Motor Systems-$25/HP			XX		XX	EE
19) Standby Generator With Backfeed							
- 500 KW/Customer Exported	SG W/Backfeed 500 KW/Cus			XX		XX	I
- 1000 KW/Customer Exported	SG W/Backfeed 1000 KW/Cus			XX		XX	I
- 1500 KW/Customer Exported	SG W/Backfeed 1500 KW/Cus			XX		XX	I
- 2000 KW/Customer Exported	SG W/Backfeed 2000 KW/Cus			XX		XX	I
20) Standby Generator - Capacity Improvement							
- $ 5,000 Payment/Customer	SG-CIP $ 5,000/Cus			XX		XX	I
- $ 7,500 Payment/Customer	SG-CIP $ 7,500/Cus			XX		XX	I
- $10,000 Payment/Customer	SG-CIP $10,000/Cus			XX		XX	I
21) Standby Generator - Category C	SG-Cat C			XX		XX	I
22) Residential High Efficiency Lighting	Res HE Ltg			XX		#	EE
23) Metal Finishing - Recover Plating Solutions	Metal Finishing			XX		#	EN
24) Textile - Reduction of Waste-Water Effluent	Textile Waste-Water			XX		#	EN

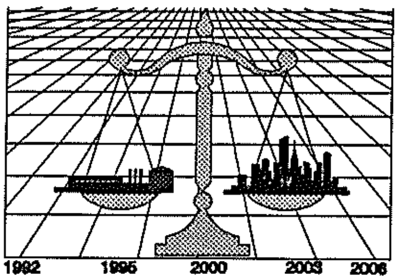
- Not Forwarded to Resource Integration

I - Interruptible
LS - Load Shift
EE - Energy Efficiency
EN - Environmental

6.5 Summary: The demand-side options briefly addressed in this Executive Summary and more fully described in Volume II are listed in Exhibit ES 6-4. The demand-side function of the planning process is to provide demand-side programs (both existing and revised) and possible new demand-side options into the integration process. The demand-side process has produced a significant improvement in both the numbers and types of energy-efficient options and either enhanced or maintained interruptible and load-shift options that are included in this Integrated Resource Plan.



7 Supply-Side Resources



7.1 Purpose: The purpose of the supply-side function of the planning process is to provide the supply-side (generation) resources that were considered in the planning process to meet Duke's anticipated future demand and energy requirements.

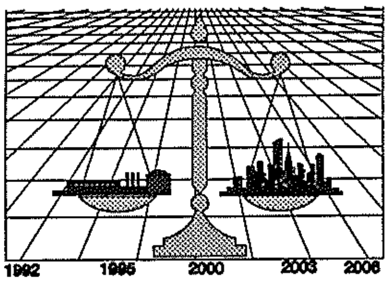
7.2 Supply-Side Options: Supply-side studies provide the power-generation options along with their costs, schedules and operating characteristics which are available to meet the electrical needs of Duke's customers over the period of the forecast. Included in Exhibit ES 7-1 and fully described in Section 7 of Volume II are the supply-side resources that were reviewed for the planning process and the resolution of each.

Exhibit ES 7-1: Supply-Side Resources Summary

	Eliminate Resources Not Viable	Perform Screening Curve Analysis	Forwarded to Resource Integration	Forwarded to Risk Assessment
Conventional Technologies				
Conventional Hydroelectric	XX			
Conventional Pulverized Coal		XX	800MW 1200MW	400MW 2-600MW
Light Water Reactor		XX		XX
Pumped Storage Hydro		XX		XX
Combustion Turbine		XX	XX	
Combined Cycle		XX	XX	
Oil-Fired Boiler		XX		
Gas-Fired Boiler		XX		
Diesel Generator		XX	XX	
Demonstrated Technologies				
Atmospheric FBC		XX		XX
Circulating FBC		XX		XX
Advance Comb. Turb.		XX	XX	
Gasification/Combined Cycle		XX		
Solid Oxide Fuel Cells		XX		
Phosphoric Acid Fuel Cells		XX	XX	
Molten Carbonate Fuel Cells		XX		
Municipal Refuse Steam		XX		
Refuse Derived Fuel		XX		
Modular Mass Burn		XX		
Lead Acid Battery Storage		XX		
Wind Power		XX		
Compressed Air Energy Storage		XX		
Geothermal	XX			
Emerging Technologies				
Advanced Pulv. Coal/Chiyoda FGD		XX		
Advanced Pulv. Coal/Spray Dryer		XX		
Pressurized FBC		XX		
Gasification/Gas-Fired Boiler		XX		
High Temp. Gas Cooled Nuclear		XX		
Passive Adv. Water Reactor		XX		
Solar Central Receiver		XX		
Solar Photovoltaic Collector		XX		
Advanced Batteries		XX		XX
Underground Pumped Storage Hydro		XX		

7.3 Summary: The supply-side resources and their primary disposition are listed in Exhibit ES 7-1 and are more fully considered in Section 7 of Volume II. is summarized in Exhibit ES 7-1.

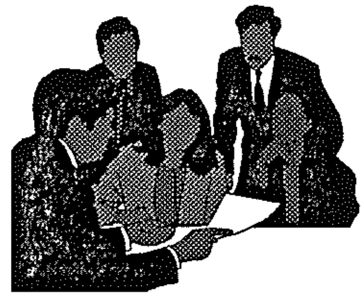
8 Purchased Resources



8.1 Purpose: The economic purchase of capacity and energy from Non-Utility Generators and from other electric utilities is important in the planning process. It allows alternatives for meeting our customers' power requirements. The region also benefits through purchases and sales that result in the effective and economic use of surplus capacity and energy from another electric utility; the efficient utilization of waste steam from a cogeneration project; or the use of renewable resources or waste for fuels used in generating electricity.

8.2 Non-Utility Generation: Purchased Resource options are evaluated to determine the total net benefit of the purchase to Duke's customers, taking into consideration costs, benefits, uncertainties and reliability. Purchased-resource options may be available from cogenerators and small-power producers (classified as Qualifying Facilities under the Public Utility Regulatory Policies Act), from Independent Power Producers (which are not Qualifying Facilities under the act), and from other utilities. Duke continues to refine its purchased-resource evaluation process to reduce the cost and time spent in evaluating proposals.

8.3 Inter-Utility Contracts and Negotiations: Duke keeps abreast of inter-utility purchased power opportunities through periodic contacts with other utilities, selective solicitations for quotes for power, and evaluation of request for proposals from other utilities. Inter-utility purchased power opportunities are evaluated by comparison with alternatives with regard to cost, availability and reliability. The amount of capacity available for long term purchase in the southeast has decreased since 1988. The cost of capacity still available for purchase in the southeast is not currently competitive with supply-side options. However, many short-term opportunities for the sale and purchase of capacity and energy remain viable.

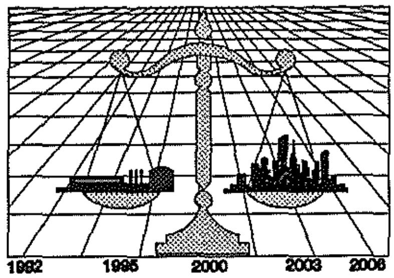


8.4 Competitive Procurement of Purchased Resources: Duke is currently developing a competitive bidding process and a request for proposal which can be utilized for future capacity needs. A draft of the competitive procurement process and request for proposals package is expected to be completed in December 1992. The timing of future capacity needs identified in the current planning process is such that the release of a request for proposal or other form of competitive solicitation and evaluation is not required in the time frame covered by the Short-term Action Plan.

8.5 Existing Purchased Resources: Duke has available 486 megawatts of purchased capacity for the year 1992 which is detailed in Section 4.7 of this Executive Summary.

8.6 Summary: Duke will continue to evaluate sources for purchased resources and use those which are found to be in the best interests of the customer. Once a contractual agreement is reached between the parties, the purchased resource is included in the integrated planning process.

9 Resource Integration:

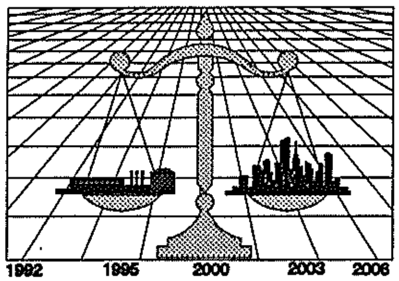


9.1 Purpose: The purpose of Resource Integration is to arrive at a combination of supply-side and demand-side options that will meet the customers' needs over the forecast period. Duke's resource integration process and its conclusions are described in detail in Section 9 of Volume II.

9.2 Evaluation: The integration process uses a number of analytical planning models to perform a sophisticated numerical analysis. This process integrates the available demand-side options with the supply-side options to meet the forecasted peak demand and energy needs along with a minimum reserve margin. This process also incorporates the available purchased-resource options along with the existing demand-side and existing supply-side resources as well as the influences of the current and projected environments to create several viable alternative plans.

9.3 Summary: As a result of the resource integration process, several plans -- combinations of supply-side and demand-side options -- were created that meet Duke's and the customers' objectives. These plans are forwarded to the next step in the process -- Risk Assessment -- which is described in Section 10 of both the Executive Summary and of Volume II.

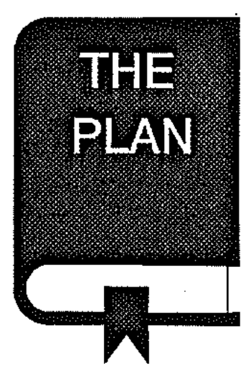
10 Risk Assessment:



10.1 Purpose: As indicated in Section 1 of this Executive Summary, there are a considerable number of risks that could have an impact on an integrated resource plan. Section 10 of Volume II addresses -- through both objective and subjective analysis -- the risks and uncertainties of forecasting the future.

10.2 Evaluation: Risk Assessment involves the application of a number of modelling techniques, described in detail in Section 10 of Volume II, that address the uncertainty of: one assumption; multiple assumptions; or a whole plan at a time. From the results of these modelling techniques, the combination of supply-side and demand-side options (adjusted for uncertainty of the input data) becomes the Integrated Resource Plan.

10.3 Summary: As a result of the risk-assessment process, Duke's recommended Integrated Resource Plan is defined.



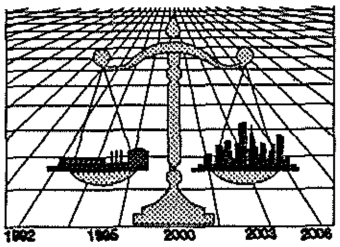
- Duke believes the current plan chosen by the risk-assessment process accomplishes the following:

  - Delays the decisions on supply-side capacity additions.
  - Represents a reasonably achievable amount of demand-side management capacity.

- Positions Duke in the strategically important energy-efficiency markets -- specifically motor systems and lighting.
- Has lower costs than other scenarios.
- Has sufficient demand-side management accomplishments to move the first baseload addition from 2003 to 2006.

- This Plan will be covered in detail in Section 11 of this Executive Summary and in Section 11 of Volume II.

11 The Integrated Resource Plan



11.1 Purpose: The purpose of the Integrated Resource Plan -- described in full both in Section 11 of this Executive Summary and in Section 11 of Volume II -- is the result of the planning process and represents Duke's long-term plan to fulfill its customers' needs over the next 15 years.

11.2 Plan Summary

15-Year Plan

- **Description:** The 1992 Integrated Resource Plan (IRP) is the culmination of a year-long process that evaluates Duke Power's system needs over the next 15 years. As indicated in the description of the planning process (Sections 1 though 10, of both Volume I and Volume II), the resulting Integrated Resource Plan incorporates existing and scheduled resources along with demand-side, supply-side and purchased-resource options to determine a proposed course of action that -- over the next 15-year period -- will ensure that the power demands of the service area will be economically and reliably met.

- **Results:** The results of the 1992 IRP show that additional supply-side resources are not required to be in place before 1995. The combination of the current forecast, growing demand-side programs, and return of the plant-modernization-program fossil units, provides Duke additional time in which to make firm decisions regarding the construction of the Lincoln Combustion Turbine Station. It also allows time for piloting aggressive demand-side programs. These programs include demand-side resources such as motor systems and high-efficiency lighting.

> **1992 IRP Results**
>
> **Additional supply-side resources are not required before 1995.**

- **Additional Resources:** Additional resources will be required during the planning horizon. The Integrated Resource Plan shows that a phasing-in of a combination of demand-side programs coupled with a peaking technology, combustion turbines, will provide the best selection of resources to meet our customers' needs through most of the 15- year time period. Near the end of the planning horizon, however, Duke anticipates a base load technology will be required. Currently this requirement is most economically met with coal-fired resources. Our base-load decision, however, will not be mad in the near term. Future integrated resource plans will address the need and type of additional baseload capacity.

> **The Plan**
>
> - **Additional Demand-Side Management**
> - **Additional Peaking Capacity**
> - **Additional Base Load**

Due to anticipated advances in construction techniques, licensing, and air-emission advantages with respect to fossil-fired alternatives, nuclear power may receive increased consideration as a potentially viable baseload solution.

- **Piloting:** This Integrated Resource Plan calls for a significant amount of piloting of demand-side management options over the next several years. This is because a pilot may take several years to address the uncertainties or other concerns being targeted. Upon completion of the pilot, the option will be reanalyzed.

- **The Plan Summary:** Exhibit ES 11-1 provides a summary of the supply-side resources and cumulative effect of the available demand-side management options presented in the 1992 Integrated Resource Plan. Major strides in the effective use of demand-side management options are evident in this Integrated Resource Plan. Of the six new demand-side management options included, non-residential high-efficiency indoor lighting and motor systems are seen as the major avenues to Duke's demand-side management success.

Major Strides in the effective use of demand-side management options are evident in Duke's plan.

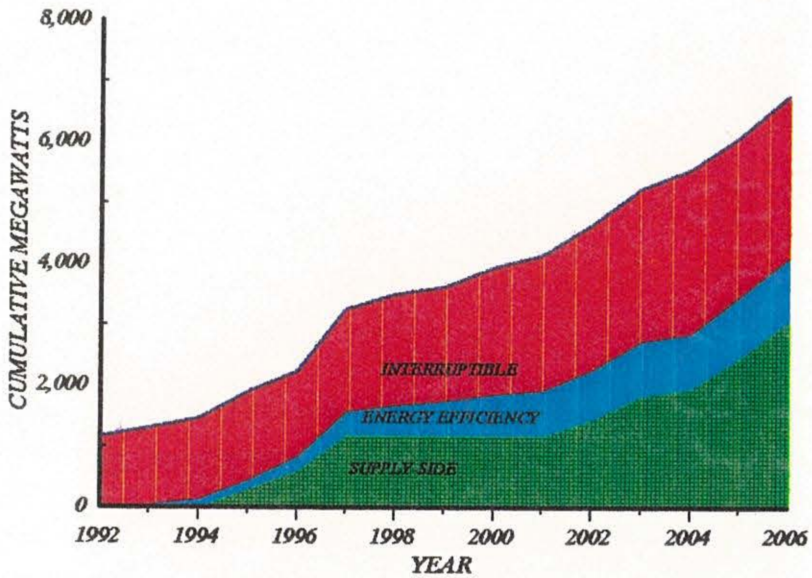
Exhibit ES 11-1: 1992 Integrated Resource Plan

Year	Supply-Side Resources			Demand-Side Resources
	74MW CT (MW)	128MW CT (MW)	600MW Coal (MW)	Cumulative MNDC[1] (MW)
1992				1165
1993				1305
1994				1459
1995	296			1599
1996	296			1641
1997	592			2065
1998				2313
1999				2431
2000				2750
2001				2958
2002		256		3194
2003		384		3403
2004		128		3582
2005		512		3611
2006			600	3689

[1] Note: MNDC = Maximum Net Dependable Capability

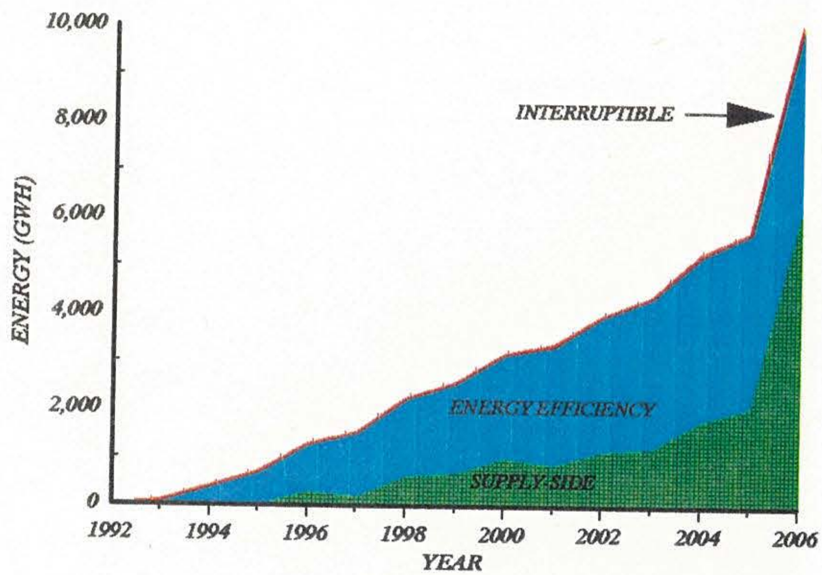
11.3 Capacity Mix: Exhibit ES 11-2 provides a graphical representation of the capacity mix of the future resources that are represented in the 1992 Integrated Resource Plan.

Exhibit ES 11-2: Future Resources Capacity Mix



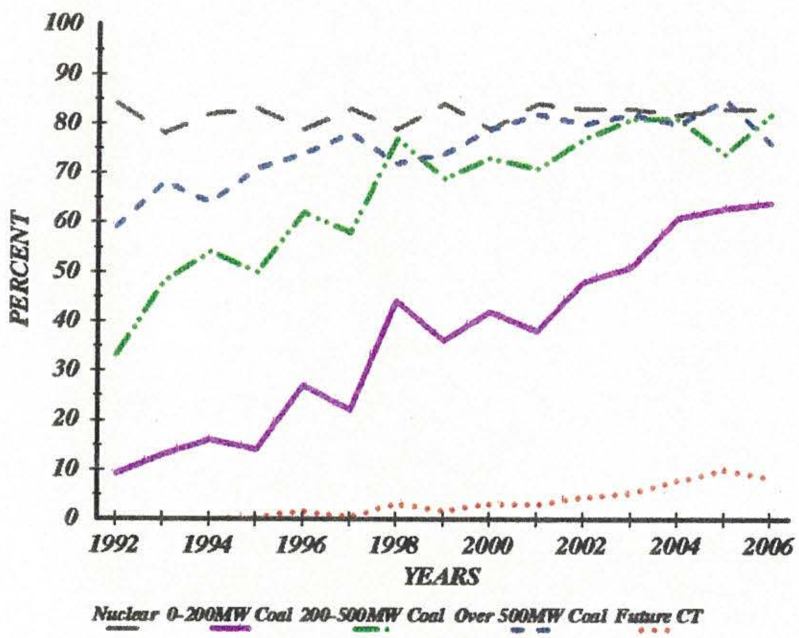
11.4 Energy Projection: Exhibit ES 11-3 provides a graphical projection of the energy usage of the demand-side management and supply-side resources to be added in the future.

Exhibit ES 11-3: Future Resource Energy Projections



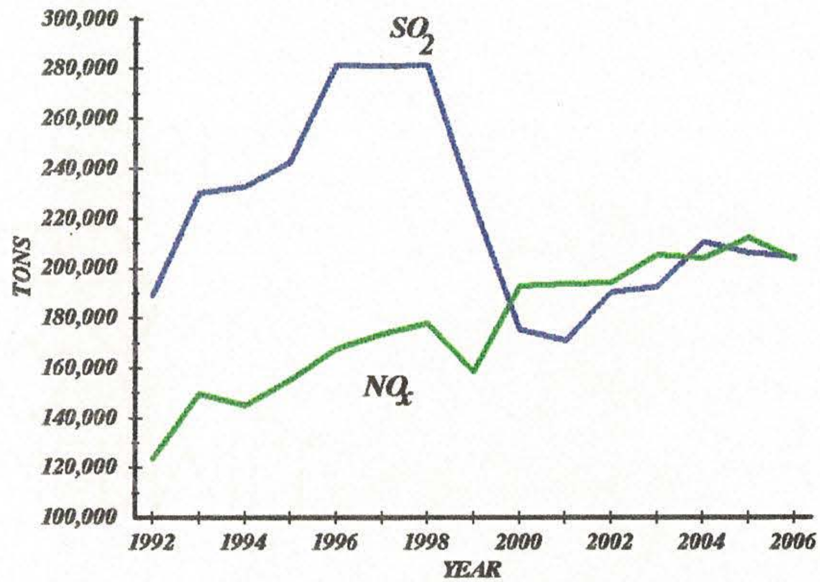
11.5 Capacity Factor Projection: Exhibit ES 11-4 shows a projection of the capacity factor for different groupings of existing and future generating units on the Duke system. Note the increased reliance on older fossil units to provide the additional energy consumed in the later years. This growth is due to increased energy sales without additional baseload options being added to the system.

Exhibit ES 11-4: Capacity Factor Projections



11.6 Emissions: Exhibit ES 11-5 provides the projections of emissions for SO_2 and NO_x for the 1992 Integrated Resource Plan.

Exhibit ES 11-5: SO_2 and NO_x Emission Projections



11.7 Load Capacity and Reserves: Exhibit ES 11-6 will detail the resources in the 1992 Integrated Resource plan for 15-year planning horizon in a Load, Capacity and Reserves Table. Several data assumptions have changed since June 1991 when the integrated planning work was performed. These assumptions are discussed in detail in the notes following Exhibit ES 11-6.

Exhibit ES 11-6: Projections of Load, Capacity and Reserves

FOR DUKE POWER COMPANY AND NANTAHALA POWER & LIGHT

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1 DUKE SYSTEM FORECAST PEAK	14,852	15,169	15,549	15,990	16,383	16,798	17,248	17,724	18,069	18,519	18,949	19,429	19,772	20,185	20,590
2 NP&L SYSTEM FORECAST PEAK	137	140	143	147	150	153	157	160	163	167	170	174	178	181	184
3 COINCIDENT DUKE/NP&L	14,983	15,303	15,687	16,131	16,527	16,946	17,399	17,877	18,226	18,679	19,113	19,596	19,943	20,359	20,768
4 DUKE GENERATING CAPACITY	17,712	17,712	17,915	18,029	18,325	18,621	19,213	19,213	19,213	19,213	19,213	19,213	19,213	19,213	19,213
5 NP&L GENERATING CAPACITY	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
6 PMP RETURNS	0	203	114	0	0	0	0	0	0	0	0	0	0	0	0
7 SCHEDULED ADDITIONS	0	0	0	296	296	592	0	0	0	0	0	0	0	0	0
8 CAPACITY RETIREMENTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(67)
9 TOTAL GENERATING CAPACITY	17,812	18,015	18,129	18,425	18,721	19,313	19,313	19,313	19,313	19,313	19,313	19,313	19,313	19,313	19,246
10 CUMULATIVE PURCHASES	493	493	493	293	293	293	293	293	293	293	293	293	293	293	293
11 CUMULATIVE SALES	0	(400)	(400)	(400)	(400)	(400)	(400)	0	0	0	0	0	0	0	0
12 UNSCHEDULED CAPACITY															
CT'S	0	0	0	0	0	0	0	0	0	0	256	384	128	512	0
COAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
13 TOTAL PRODUCTION CAPACITY	18,305	18,108	18,222	18,318	18,614	19,206	19,206	19,606	19,606	19,606	19,862	20,246	20,374	20,886	21,419
14 GENERATING RESERVES - MW	3,322	2,805	2,535	2,187	2,087	2,260	1,807	1,729	1,380	927	749	650	431	527	651
15 RESERVE MARGIN	22.2%	18.3%	16.2%	13.6%	12.6%	13.3%	10.4%	9.7%	7.6%	5.0%	3.9%	3.3%	2.2%	2.6%	3.1%
16 CAPACITY MARGIN	18.1%	15.5%	13.9%	11.9%	11.2%	11.8%	9.4%	8.8%	7.0%	4.7%	3.8%	3.2%	2.1%	2.5%	3.0%
17 CUMULATIVE DSM CAPACITY	1,165	1,305	1,459	1,599	1,641	2,065	2,313	2,431	2,750	2,958	3,194	3,403	3,582	3,611	3,689
18 TOTAL EQUIVALENT CAPACITY	19,470	19,413	19,681	19,917	20,255	21,271	21,519	22,037	22,356	22,564	23,056	23,649	23,956	24,497	25,108
19 EQUIVALENT RESERVES - MW	4,487	4,110	3,994	3,786	3,728	4,325	4,120	4,160	4,130	3,885	3,943	4,053	4,013	4,138	4,340
20 RESERVE MARGIN	29.95%	26.86%	25.46%	23.47%	22.56%	25.52%	23.68%	23.27%	22.66%	20.80%	20.63%	20.68%	20.12%	20.33%	20.90%
21 CAPACITY MARGIN	23.0%	21.2%	20.3%	19.0%	18.4%	20.3%	19.1%	18.9%	18.5%	17.2%	17.1%	17.1%	16.8%	16.9%	17.3%

Notes to Exhibit ES 11-6

The following notes are numbered to match the line numbers on the 1992 Integrated Resource Plan.

2. Duke Power Company and Nantahala Power and Light systems were interconnected upon completion of the Shuler line on October 1, 1990.

3. Planning is done for the coincident peak demand for the two systems.

5. Nantahala hydro capacity was added on October 1, 1990.

6. Plant Modernization Program (PMP) capacity returns to service per the March 1991 schedule.

7. The scheduled additions are those approved for construction. The additions shown are for the 74 MW Lincoln Combustion Turbine Station units. The dates of operation will remain flexible to accommodate changes in resource needs.

8. There are no firm schedules for unit retirements. The 67 MW retirement shown in 2006 represents a retire/replace/refurbish decision date for Dan River Steam Station #2.

10. Cumulative purchases have several components. All years include the following purchases from SEPA, customer generation (COGEN), and small power producers (SPP):

SEPA	238
COGEN	55
TOTAL	293

An additional contract for 200 MW of capacity is shown in 1992 through 1994.

11. Cumulative sales represent the CP&L sale.

12. Unscheduled capacity represents new capacity resources or capability increases which are being considered. Neither the date of operation, the type of resource, nor the size is firm. All capacity additions beyond 1997 represent that capacity required to maintain the 20% minimum planning reserve margin. The combustion turbines shown in this period are the 128 Megawatts Advanced Combustion Turbines.

15. Reserve margin is shown for reference.

16. Capacity margin is the industry standard term. A 16.67 percent capacity margin is equivalent to a 20.0 percent reserve margin.

17. Cumulative DSM capacity represents the demand-side management contribution toward meeting the load. The DSM programs reflected in these numbers include interruptible load-shift and energy-efficiency programs. The value shown is the amount of maximum net dependable capability that the DSM programs have displaced.

Assumption Updates for Exhibit ES 11-6

Several assumptions used in the integrated planning process have been updated since the work was performed in 1991. Exhibit 11-6 contains the updated data. The following notes describe the assumptions used in the planning process as compared to those reflected in Exhibit 11-6. The notes are numbered to match the line numbers in Exhibit 11-6.

5. Nantahala Power and Light generating capacity assumed 99 MW was available for all years of the study. Exhibit 11-6 reflects 100 MW.

8. A capacity retirement of 30 MW in 1998 represented a removal of "increased pumped hydro capability" due to high-head operation at Jocassee. A capacity retirement of 172 MW in 1998 represented a removal of high-head operation at Bad Creek. Based on analysis of forecast changes and DSM programs, Duke has discontinued the high-head operation and adjusted the capacity of Jocassee and Bad Creek to fully utilize their impoundments. This will make the capacity of both plants consistent with the license ratings. Exhibit 11-6 line 4 now reflects that the "increased pumped hydro capability" has been removed from the system.

10. The customer generation (COGEN) and small power producers (SPP) capacity was assumed to be equal to 48 MW. Exhibit 11-6 reflects 55 MW.

11. The 400 MW CP&L sale was assumed to occur from 1992 through 1997. Exhibit 11-6 reflects the sale occurring from 1993 through 1998.

The effects of these updates do not change the results determined by the planning process that are presented in this document.

11.8 Demand-Side Programs and Options: Exhibit ES 11-7 provides a list of the existing demand-side management programs and new demand-side management options that will be implemented into programs starting in 1992. The projected MW and megawatt-hours accomplishments are provided for each demand-side management program:

Exhibit ES 11-7: Demand-Side Management Programs in 1992 IRP

PROGRAM	Megawatts			Megawatt Hours		
	1994	2000	2006	1994	2000	2006
Res LC - W/H	(46.2)	(65.5)	(70.2)	0	0	0
Res LC - A/C	(682.9)	(1,178.7)	(1,353.8)	0	0	0
Res Off Peak W/H	(16.6)	(24.6)	(24.6)	0	0	0
H.E. Heat Pump -Res	(3.7)	(3.7)	(3.7)	(8,558)	(8,558)	(8,558)
H.E. Central A/C -Res	(1.3)	(1.3)	(1.3)	(1,601)	(1,601)	(1,601)
Res Dual Fuel HP	(24.3)	(36.5)	(36.5)	30,438	45,762	45,762
H.E. Freezers - Res	(.2)	(.2)	(.2)	(1,844)	(1,844)	(1,844)
H.E. Refrigerators - Res	(.4)	(.4)	(.4)	(2,909)	(2,909)	(2,909)
Res Insulation New Resid	(20.2)	(74.6)	(74.6)	87,864	324,269	324,269
Res Insulation Loan	(0.7)	(1.1)	(1.1)	(16,463)	(27,438)	(27,438)
IS	(566.5)	(660.9)	(1,038.5)	0	0	0
SG W/O Backfeed	(54.4)	(92.7)	(110.1)	0	0	0
H.E. Chillers for A/C	(8.9)	(43.8)	(70.4)	(21,655)	(106,729)	(171,695)
H.E. Unitary Equip for A/C	(4.9)	(19.1)	(33.5)	(3,598)	(13,998)	(24,463)

Note: Values in parentheses are reductions

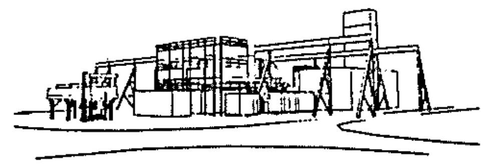
11.9 Demand-Side Pilots: Exhibit ES 11-8 provides a list of demand-side management options that will be piloted starting in 1992. The projected megawatt and megawatt-hour accomplishments if the pilots are implemented into the programs are provided for each demand-side management option listed.

Exhibit ES 11-8: Demand-side Management Pilots In 1992 IRP

PROGRAM	Megawatts			Megawatt Hours		
	1994	2000	2006	1994	2000	2006
Res W/H Blanket	(2.7)	(4.7)	(4.7)	(30,954)	(53,065)	(53,065)
Res HVAC Tune-Up	(5.5)	(51.2)	(51.2)	(11,470)	(105,930)	(105,930)
Non-Res H.E. Ltg - El Htg - Existing	(26.9)	(107.4)	(188.0)	(78,258)	(313,032)	(547,805)
Non-Res H.E. Ltg - El Hgt - New	(12.3)	(49.3)	(86.3)	(35,906)	(143,625)	(251,345)
Non-Res H.E. Ltg - Fossil Htg - Existing	(25.7)	(102.7)	(179.7)	(109,359)	(437,435)	(765,511)
Non-Res H.E. Ltg - Fossil Htg - New	(24.7)	(98.9)	(173.1)	(105,344)	(421,377)	(737,409)
Non-Res H.E. Ltg - OPT - Existing	(13.4)	(53.7)	(94.0)	(86,176)	(344,704)	(603,233)
Non-Res H.E. Ltg - OPT - New	(3.0)	(12.0)	(20.9)	(19,210)	(76,838)	(134,467)
Motor Systems - $6/HP	(24.4)	(170.5)	(267.9)	(142,095)	(994,667)	(1,563,047)

Note: Values in parentheses are reductions

11.10 Supply-Side Contributions:



- **Additional Capacity:** Before the year 2000, Duke will need additional capacity to meet customer demand. The supply-side option that most economically meets the near-term needs is peaking capacity. This peaking capacity is best served by combustion turbines. In the near-term, 74 megawatt combustion turbines prove the most effective in meeting our capacity needs and will also provide a benefit of quick-start capability to meet spinning reserves. Around the turn of the century, 128 megawatt combustion turbines will be used as the most economical means to meet the peaking needs.

- **74 Megawatt Combustion Turbines:** As fully described in Volume II, the 74 megawatt combustion turbines in the 1992 Integrated Resource Plan and in the 1990 and 1991 Short Term Action Plans presented are the Lincoln Combustion Turbine Station units. The 1992 Integrated Resource Plan shows the first Lincoln units available in 1995.

The first Lincoln units will be available by 1995

- **New Base-load Technology:** Near the end of the planning horizon, Duke anticipates a base-load technology will be required. Currently, this technology is most economically met with coal-fired resources. However, the base-load decision is not near-term. Future integrated resource plans will address the type and need of additional

Base-load technology will be required in 2006

base-load capacity. Due to anticipated advances in construction techniques, licensing, and air-emission advantages with respect to fossil-fired alternatives, nuclear power may receive increased consideration as a potentially viable base-load solution.

11.11 Resource Strategies:

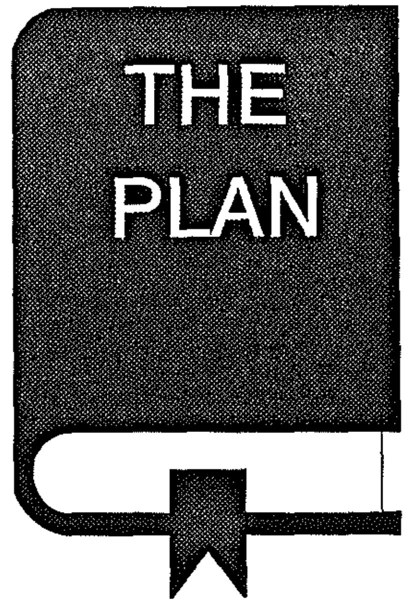
The resources in the IRP provide flexibility

- **Adequate Needs:** The resource options shown in this Integrated Resource Plan are more than Duke is anticipated to need in order to meet the demand and energy requirements of the service area through 2006. There are two major considerations regarding the surplus of resources over the forecasted need.

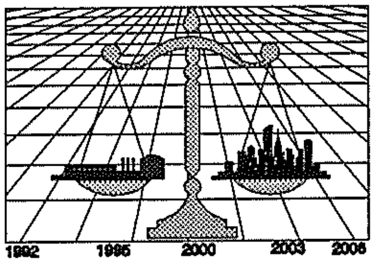
  - **Consideration #1:** The first reason is that the selected resources do not require commitments today because reserves appear to be adequate for the next several years and each anticipated option has relatively short lead times for implementation. This has allowed Duke the opportunity to maintain a great deal of flexibility in this Integrated Resource Plan by developing a resource menu consisting of demand-side programs and combustion turbine options from which to choose the proper resource mix to meet the forecasted needs.

  - **Consideration #2:** As outlined in Section 2.4.3 of Volume II, there are a number of key issues facing Duke over the next fifteen years. The resource options/mix selected from the resource menu to meet the demand and energy requirements of the service area will be determined, in large part, by the outcome of these issues.

11.12 Summary: Duke's year-long planning process has resulted in a completed plan for the 1992 through 2006 period and has determined that additional supply-side resources are not required to be in place before 1995. The plan also concludes Duke has additional time to further consider aggressive demand-side options before making a final decision on construction of the Lincoln Combustion Turbine Station.



12 Short Term Action Plan



12.1 Introduction: This Short Term Action Plan details the actions Duke will undertake <u>over the next three years</u> to implement the 1992 Integrated Resource Plan and improve the planning process. Duke's Short Term Action Plan was developed to provide flexibility for meeting future demand and energy requirements in a cost-effective manner. Duke's strategy for the next three years will involve developing the integration of options available in this Integrated Resource Plan by focusing on the following objectives:

- **The 1992 Integrated Resource Plan Implementation Objectives:**

  - Continue with the necessary preparations to achieve a 1995 operation date for the first phase of the Lincoln Combustion Turbine Station.

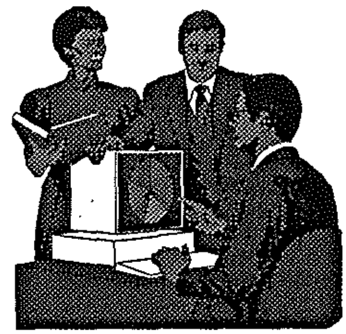
  > - **Prepare**
  > - **Develop**
  > - **Implement**

  - Develop and implement pilot projects for designated demand-side options.

  - Implement new demand-side programs designated in the Integrated Resource Plan through internal means or competitive bidding.

  - Continue existing demand-side programs designated in the Integrated Resource Plan through internal means or competitive bidding.

- **Actions and Activities of the Integrated Planning Process:**



  - Continue to monitor and evaluate developments regarding environmental externalities.

  - Continue to identify reliability and efficiency improvements to existing generating and power-delivery facilities.

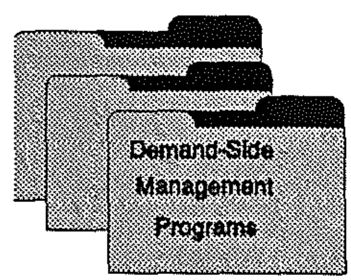
  - Continue to improve end-use forecasting techniques.

  - Continue to improve screening and modelling techniques used in the integrated planning process.

  Note: Details of the Short Term Action Plan are summarized in the sections that follow.

12.2 Demand-Side Actions

12.2.1 Programs: As a result of the 1992 Integrated Resource Plan, Duke will implement two new demand-side management programs: (1) High Efficiency Chillers for Air Conditioning and (2) High Efficiency Unitary Equipment for Air Conditioning. The chiller program is scheduled for commission filing in the first quarter of 1992 with implementation in the second quarter. The unitary air-conditioning program is scheduled for



Two DSM Programs

commission filing in the second quarter of 1992 with implementation either late in the second quarter or early in the third quarter.

12.2.2 Pilot Projects:

- **Completed Pilots:** Three pilots were completed since the last Short Term Action Plan:

  - **Non-residential Heat Treating Load Shift**
  - **Industrial High Efficiency Dust Collection**
  - **Standby Generator With Backfeed**

- **New Pilots:** As a result of the 1992 Integrated Resource Plan, three new pilots will be filed with the commissions and will begin the piloting process in 1992:

  - **Residential HVAC Tune-Up**
  - **Motor Systems**
  - **Residential Water Heater Insulating Blanket**

- **Pilots to be Completed:** During the period covered by this Short Term Action Plan, seven pilots will be completed. The pilots and their completion dates are shown in Exhibit ES 12-1: Pilot Completion dates.

Exhibit ES 12-1: Pilot Completion Dates

Pilot Program	Completion Date
Residential High Efficiency Lighting	1992
Residential Water Heater Insulating Blanket	1992
Non-Residential Air Conditioning Load Control	1992
Residential High Efficiency Ground Coupled Heat Pump	1993
Residential HVAC Tune-Up	1993
Non-Residential Air Conditioning Load Shift (Cool Storage)	1993
Non-Residential High Efficiency Indoor Lighting	1994

- Motor Systems pilot will begin research in 1992. Other target dates have yet to be determined. These dates should be available for inclusion in the 1993 Short Term Action Plan.

12.2.3 Accomplishments - Current and projected:

- **Current Demand-Side Management Accomplishments:** The reported megawatt accomplishments of the existing programs through December of 1991 are listed in Exhibit ES 12-2.

Exhibit ES 12-2: Demand-Side Management Program Accomplishment Table

(Updated as of December 31, 1991)

Programs	Reduction (Total MW)	Type of Program
Residential		
Residential Load Control-Water Heater	30.5	Interrupt
Residential Load Control-Air Conditioning	373.2	Interrupt
Residential Control Off-Peak Water Heating	9.1	Load Shift
High Efficiency Heat Pump Payment	1.1	Energy Eff
High Efficiency Air Conditioning Payment	0.5	Energy Eff
Residential Add-On (Dual Fuel) Heat Pump	0.2	Energy Eff
High Efficiency Freezer Payment	0.1	Energy Eff
High Efficiency Refrigerator Payment	0.4	Energy Eff
Residential Insulation - New Residences	15.8	Energy Eff
Residential Insulation Loan	0.0	Energy Eff
Commercial/Industrial		
Interruptible Service	626.0	Interrupt
Standby Generator w/o Backfeed	32.1	Interrupt
Total	1089.0	

- **Projected Demand-Side Management Accomplishments:** Projected demand-side management accomplishments for the existing and new programs/pilots for the years of 1992, 1993 and 1994 are listed in Exhibit ES 12-3. Values in parentheses are reductions.

Exhibit ES 12-3: Demand-Side Management Accomplishments Table

	1992			1993			1994		
	Capacity (2) (KW)	Energy (3) (MWH)	Direct (3) Expendi-tures ($)	Capacity (KW)	Energy (3) (MWH)	Direct (3) Expendi-tures ($)	Capacity (KW) (2)	Energy (MWH)(3)	Direct (3) Expendi-tures ($)
EXISTING PROGRAMS									
RES LC-W/H(1)	37,913	0	4,787,838	(42,849)	0	5,051,776	(46,196)	0	5,465,324
RES LC - AC (1)	(494,936)	0	17,719,853	(598,415	0	19,715,767	(682,858)	0	22,225,197
RES OFF PEAK W/H	(13,253)	1,763	1,000,554	(15,180)	3,525	994,645	(16,565)	5,288	1,069,236
HE HEAT PUMP-RES	(2,352)	(5,429)	1,450,230	(3,709)	(8,558)	(1,656,187)	(3,708)	(8,558)	13,402
HE CENTRAL A/C-RES	(834)	(1,016)	469,709	(1,315)	(1,601)	535,594	(1,315)	(1,601)	0
RES DUAL FUEL HP	(6,170)	7,775	2,731,188	(14,150)	17,779	4,169,631	(24,256)	30,438	5,439,344
HE FREEZER-RES	(130)	(1,125)	176,286	(239)	(1,844)	213,781	(239)	(1,844)	52,441
HE REFRIG-RES	(257)	(1,848)	466,137	(449)	(2,909)	516,171	(449)	(2,909)	23,307
RES INSULATION NEW RESID	(6253)	27,187	4,745,807)	(12,869)	55,949	5,109,697	(20,210)	87,864	5,496,236
RES INSULATION LOAN	(226)	(5,488)	554,261	(452)	(10,975)	775,257	(678)	(16,463)	1,012,647
IS (1)	(556,455)	0	25,326,000	(566,455)	0	25,452,630	(566,455)	0	25,579,893
SG W/O BACKFEED (1)	(36,831)	0	1,582,012	(45,631)	0	1,934,051	(54,431)	0	2,348,107
NEW PROGRAMS/PILOTS									
HE CHILLERS OF A/C	(2,538)	(6,187)	1,075,108	(5,075)	(12,374)	1,094,212	(8,882)	(21,655)	1,662,575
HE UNITARY EQUIPMENT FOR A/C	(1,312)	(959)	434,055	(2,953)	(2,159)	536,589	(4,421)	(3,598)	650,848
RES HVAC TUNE-UP	0	0	0	(1,630)	(3,374)	1,334,104	(5,541)	11,470	2,756,379
RES W/H BLANKET	0	0	0	(782)	(8,844)	882,235	(1,760)	(19,899)	892,542
NON-RES HE LTG-EL HTG-EXISTING	0	0	0	(13,429)	(39,129)	3,126,387	(26,858)	(78258)	3,170,579
NON-RES HE LTG-EL HTG-NEW	0	0	0	(6,162)	(17,953)	1,510,959	(12,323)	(35,906)	1,532,244
NON-RES HE LTG-FOSSIL HTG- EXIST	0	0	0	(12,834)	(54,679)	3,126,175	(25,669)	(109,359)	3,164,071
NON-RES HE LTG-FOSSIL HTG-NEW	0	0	0	(12,363)	(52,672)	3,168,946	(24,726)	(105,344)	3,207,117
NON-RES LTG-OPT-EXISTING	0	0	0	(6,712)	(43,088)	1,497,579	(13,423)	(86,176)	1,519,904
NON-RES LTG-OPT-NEW	0	0	0	(1,496)	(9,605)	351,761	(2,992)	(19,210)	365,992
MOTOR SYSTEMS-$6/HP	0	0	0	0	0	0	(24,359)	(142,095)	23,170,234
TOTAL	(1,169,461)		62,519,038	(1,365,149)		82,754,122	(1,568,816)		110,808,619

Notes: (1) Energy changes negligible and assumed; (2) Estimated cumulative values (3) Estimated annual values (4) Values in Parentheses are reductions

- The Residential Water Heater Insulating Blanket option was analyzed in resource integration as being implemented as a program in 1992. Instead, this option will be piloted in 1992. Therefore, the projected demand-side management accomplishments are postponed by one year and will not begin until 1993. This is shown in Exhibit ES 12-3.

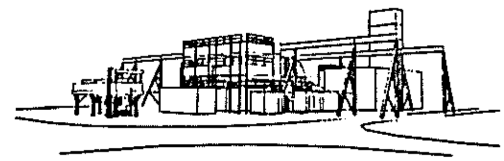
- The kilowatts in Exhibit ES 12-3 are the diversified customer's load at the time of Duke's system peak plus transmission and distribution line losses. The KW values for each year are cumulative not incremental. The megawatt-hour values are annual values and include transmission and distribution line losses. The direct expenditures are also annual values.

12.3 Supply-Side Actions:

- **Introduction:** Duke Power is planning for new generation capacity as part of an overall IRP designed to satisfy customer demand and energy requirements in a cost effective manner while providing flexibility to respond to future variables. Supply-side actions required to support and implement the IRP are presented below. Future supply-side system improvements and developmental activities are presented in Planning Enhancements (Volume II, Section 12.5).

- **Lincoln Combustion Turbine Station:** Duke will continue efforts to obtain all remaining permits required to start construction of a Lincoln Combustion Turbine Station. In addition, Duke will perform all administrative preparations to enable a construction start in early 1993.

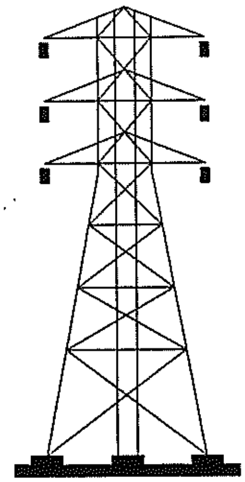
- **Advanced Combustion Turbines:** Following the Lincoln Combustion Turbines, 1280 MW of advanced combustion turbines are planned. Based on the prevailing regulatory environment and combustion-turbine technology, current estimates indicate five or six years may be needed to site, license, permit, design and construct a combustion-turbine station of this type. With 2002 projected as the earliest need for this type station, no action is required during the short-term action period.



- **Base Load Units:** The first base load addition in this plan is a 600 MW conventional pulverized coal unit scheduled for 2006. Based on the prevailing regulatory environment and fossil technology, current estimates indicate eight or nine years may be needed to site, license, permit, design, and construct a fossil unit of this type. Based on the lead-time available to meet the 2006 operational date, no action is required during the short-term action period.

12.4 Purchased Power Options:

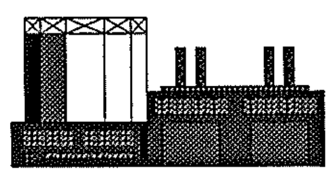
- **Purchased Power Opportunities:** Duke keeps abreast of inter-utility purchased power opportunities through periodic contacts with other utilities, selective solicitations for quotes for power, and evaluation of request for proposals from other utilities. Inter-utility purchased power opportunities are evaluated by comparison with alternatives with regard to cost, availability and reliability. The amount of capacity available for long-term purchase in the southeast has decreased since 1988. The cost of capacity still available for purchase in the southeast is not currently competitive with supply-side options.



- **Nantahala Power Purchase:** Duke is currently purchasing 200 megawatts of electricity from Nantahala Power and Light which Nantahala has purchased from Tennessee Valley Authority. This purchase will continue through 1994.

- **Catawba Nuclear Station:** Duke is in various stages of negotiation with the co-owners of the Catawba Nuclear Station regarding the terms and conditions for the possible transfer and replacement of a portion of the co-owner's project capacity and energy off the Duke system. The timeframe of any such transfer(s), if ultimately agreed upon by all parties, is not currently known but would not commence until the mid 1990s.

- **Neighboring Utilities:** Duke is negotiating new interconnection agreements and other power contracts with neighboring utilities with whom Duke has no current agreements. These new agreements will offer more opportunities for Duke to purchase and sell on a short-term basis. Duke has filed with the Federal Energy Regulatory Commission for approval of two contracts with Cajun Electric Power Cooperative: (1) one



contract for the purchase or sale of economy energy, (2) the other contract for the purchase or sale of short-term power.

- **Other Utilities:** Duke is revising existing agreements with other utilities. The revised agreements will include enhancements such as formula-based rates, ceiling capacity charges, and contract modifications which will allow purchases as well as sales of power. The revised agreements provide more flexibility in day-to-day operations with our utility neighbors.

12.5 Integrated Resource Plan Activities and Enhancements

12.5.1 Demand-Side Activities:

- **Existing Programs:** Duke plans to review each existing program annually during option development. If any new data shows that projected accomplishments or costs associated with a program will change from previous analyses, the program will be revised and included in the planning process as a new option. Existing interruptible programs will receive special attention because of their size and future potential.

- **New Options:** Duke will continue to review new technologies as potential options. They may affect a new market segment or cause an existing program to be revised.

Duke will continue to review new technologies as they become available.

- Residentially, energy efficient options will be the major focus.

- In the commercial sector, the emphasis will be on energy efficient and load shift options.

- Production and the processes that accomplish it are the most important concerns for the industrial sector.

- **Demand-Side Bidding:** As part of Duke's expanding demand-side management program the company is exploring a demand-side bidding concept. Demand-side bidding involves the competitive procurement of Demand-side management options from a third party or customer who may be able to provide such options in a better or more cost-effective manner than Duke. This concept attempts to utilize the specialized knowledge or expertise of third parties or customers to find cost-effective demand-side management options that may not be captured with utility-run programs.

  - The current schedule calls for release of a request for proposal in the summer of 1992.

  - Demand-side bidding is being run as a pilot effort to determine its effectiveness in acquiring demand-side management options.

- **Demand-Side Management Resource Assessment:** The total demand-side management Resource Assessment will be completed in 1993. A consultant will be hired in 1992 to assimilate all the data and produce the final report.

- **End-Use Metering:** Data from the Residential/Commercial End-Use Metering project will be collected through December 1993. Industrial metering opportunities will be identified with at least one installation by the end of 1992.

- **Customer Surveys:** Customer input and data collection in the form of surveys will be an ongoing and growing activity at Duke. Many questions about options and existing programs can be answered using surveys.

12.5.2 Planned Enhancements of the End-Use Technique:

- Current efforts are proceeding so that the end-use methodology will be adopted within the forecasting process during 1992. Duke is acquiring the appropriate computer software so that energy forecasts -- by end-use (or appliance) -- will be produced by the residential, commercial, and industrial customer classes. Energy reductions due to demand-side management can be calculated using these software applications.

- Work is also proceeding on load-shape forecasts by structure-type and by end-use through the application of the appropriate software and through the accumulation of the appropriate implementation of existing software. The forecasts of load shapes will directly indicate the megawatt reduction due to demand-side management after the influence of demand-side management is considered.

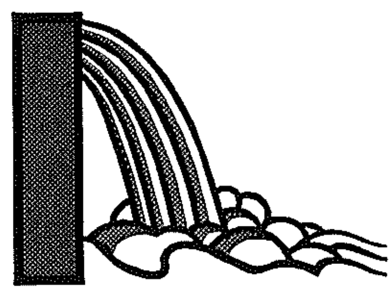
12.5.3 Supply-Side Planning Enhancements:

In order to continually improve supply-side inputs into the integrated planning process, Duke intends to pursue system improvements and developmental activities.

- **System Improvements:**

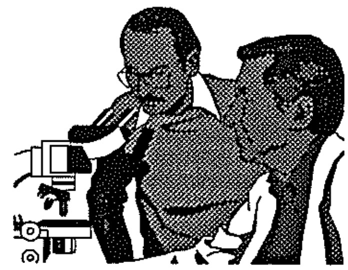
  - **Plant Modernization Program (PMP)** - Five fossil units remain to be returned to service under this program. Cost and capacity needs will determine the optimum timing for completing this work.

  - **Hydroelectric Station Improvements** - Duke has performed a study of the reliability improvement and life extension potential of various repairs, replacements, and modifications at some of Duke's hydroelectric power plants. The work on each plant will be evaluated on a case-by-case basis and considered for implementation where it proves to be cost effective and prudent.



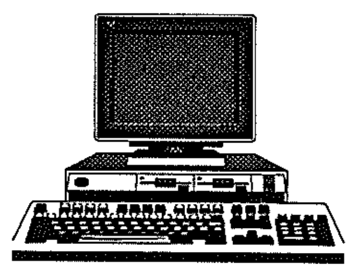
  - **Steam Generator Replacement** - The project team that has been formed to look at this issue will continue to perform conceptual designs and studies to support a decision on whether or not to replace steam generators at the McGuire and Catawba nuclear stations. The decision will consider optimum timing based on cost, unit performance, and impact on system operation and generation.

- **Developmental Activities:**



  - **Clean Air Act:** Duke is currently working on a detailed compliance plan that must be filed and approved by the Environmental Protection Agency by 1995. This plan will indicate required modifications to Duke's existing fossil units or operating practices.

  - **Externalities:** Duke will continue to monitor and evaluate developments regarding environmental externalities. Duke will also continue to include the costs of environmental compliance in its assessment of resource options. Further, Duke will continue to qualitatively consider environmental effects in resource assessment. Duke will also continue to keep abreast of developments in this area.



12.5.4 Cost Tracking: During 1991, Duke implemented a comprehensive cost-tracking system. This system is designed to capture the full cost associated with demand-side management programs, pilot projects and administration of the IRP process. The data provided by this system will be used primarily to evaluate the cost-effectiveness of demand-side management programs. In addition, these costs will be vital components in rate making, cost recovery and cost management. One of the enhancements planned for this activity includes a better linkage between the planning and budgeting process.

12.5.5 Demand-Side Program Evaluation: Evaluations are currently underway for three demand-side management programs: Air Conditioning Load Control, Water Heater Load Control and Interruptible Service. Results of these three evaluations are expected in 1992. In addition, a consultant has been hired to lead the effort to annually verify and measure the impact of each demand-side management program. This process will show whether the programs are achieving expected results.

12.6 Summary:

The Short-Term actions that Duke will undertake over the next three years will serve to implement the 1992 Integrated Resource Plan and improve the planning process.

Integrated Resource Plan 1992

VOLUME II

DUKE POWER COMPANY

TABLE OF CONTENTS

VOLUME III APPENDICES (Some sections do no have an appendix)

2.0 OVERVIEW AND OBJECTIVES

2.1 Duke Power Company, A Brief History

2.1.1 The Service Area

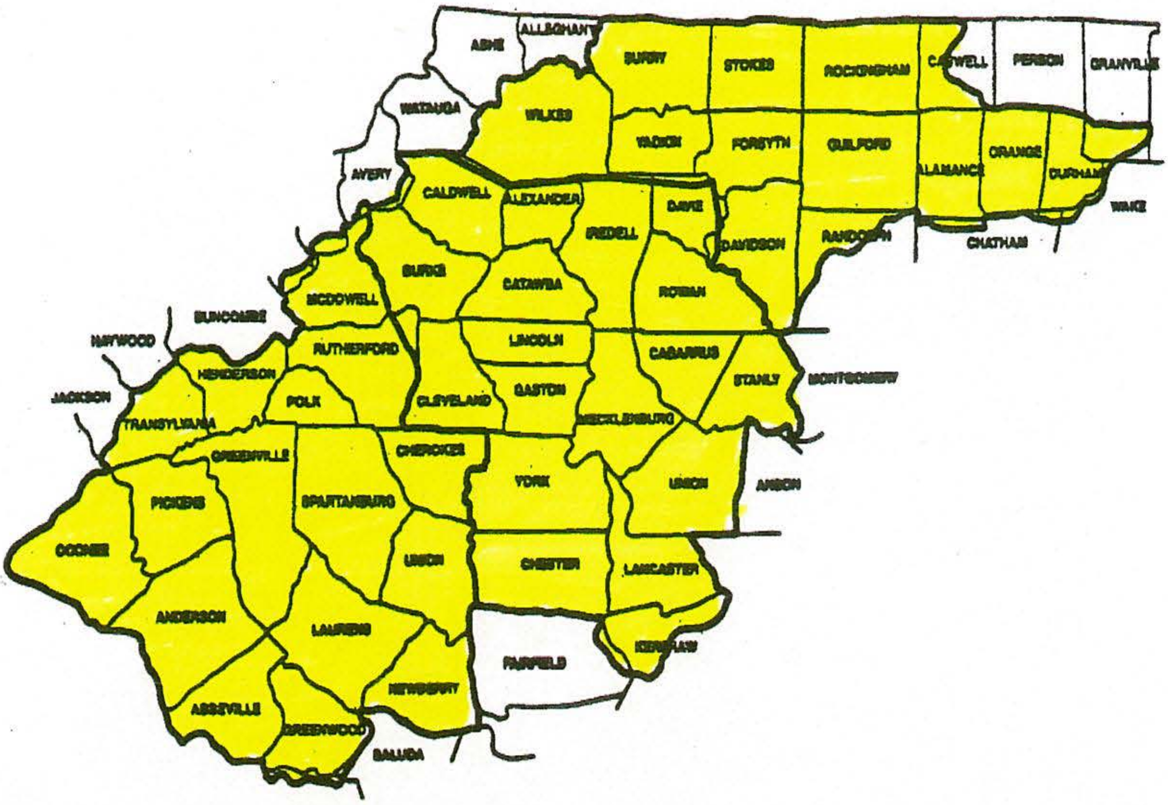
Headquartered in Charlotte, North Carolina, Duke Power supplies electricity to more than 1.6 million residential, commercial and industrial customers in a 20,000 square-mile service area in North Carolina and South Carolina. Since its founding nearly 90 years ago, the Company has grown to become the nation's seventh-largest investor-owned electric utility, serving approximately 4.6 million people in its service area. This service area is depicted in Exhibit 2-1.

Duke Power's three nuclear generating stations, eight coal-fired stations and 27 hydroelectric stations produced 69.9 billion kilowatt-hours of electricity in 1991. Electric revenues totaled $3.8 billion. About 70 percent of sales were in North Carolina and 30 percent in South Carolina.

Duke's retail customers are currently served from 90 customer service offices located throughout its service area. In addition, the Company makes wholesale, bulk power and contractual sales.

Nantahala Power and Light Company, a Duke Power subsidiary, provides electricity to another 47,000 customers in a five-county area in western North Carolina. Nantahala is headquartered in Franklin, North Carolina.

Exhibit 2-1: Duke Power Service Area



2.1.2 Demand-Side History

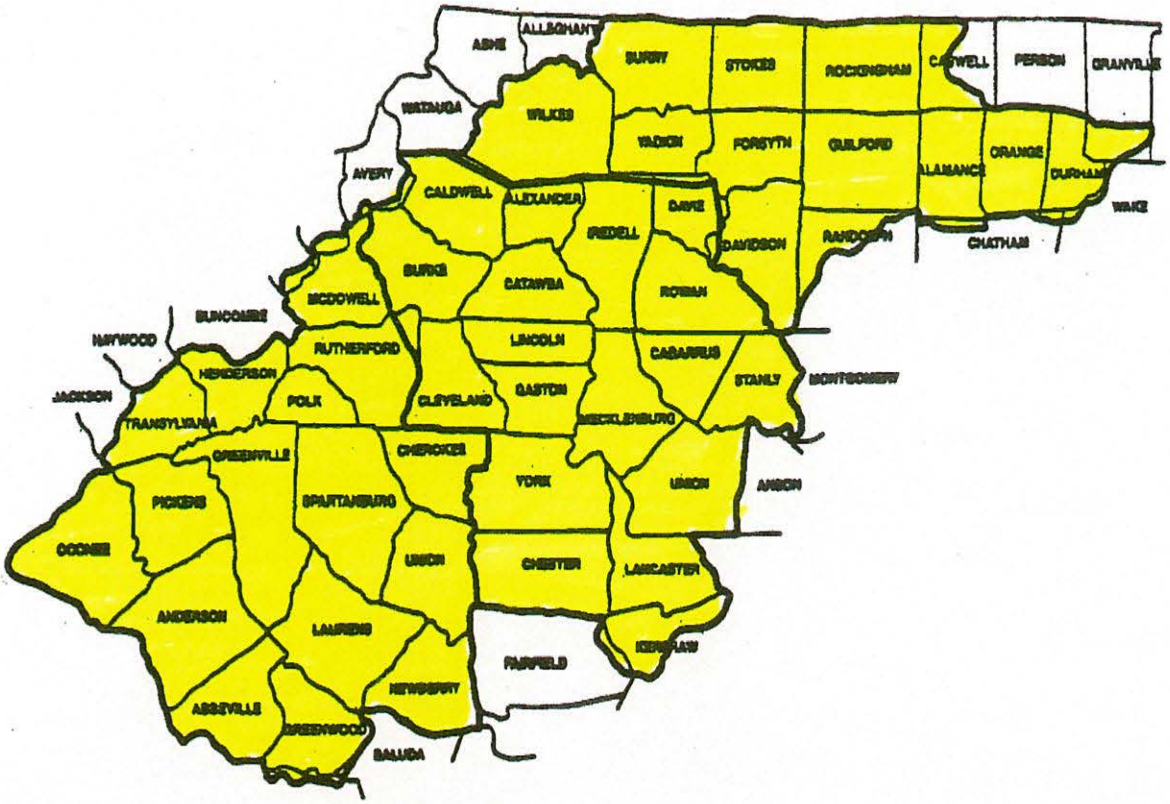
Since the mid 1970s Duke's energy efficiency programs and load management programs have become increasingly important for future planning. During the 1970s, Duke undertook a major construction program to increase baseload generating facilities. Due to escalating inflation in the early 1980s, Duke's management saw the need to implement cost-effective demand-side efforts in order to defer the need for additional facilities. Although these programs were not placed through the rigors of the current planning process, they were instrumental in curbing the growth in peak demand through energy efficiency and load shift programs. Interruptible programs were designed to permit the company to interrupt load during periods of system generating capacity shortages. Since the late 1980s, Duke has continued its demand-side efforts in a comprehensive IRP that emphasizes cost-effective DSM programs as potential alternatives to new supply-side facilities.

2.1.3 Duke and the Environment

Even before the surge in public and governmental awareness of environmental issues, Duke always placed special emphasis on protecting the environment. Recognition of Duke's efforts in this regard is shown in the numerous environmental awards it has received, including:

- National Wildlife Federation Conservation Achievement Award, 1985

Exhibit 2-1: Duke Power Service Area



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- National Wildlife Federation Conservation Achievement Award, 1985

- Honeywell Gold Nugget National Energy Conservation Award, 1989
- Renew America Environmental Achievement Award, 1990
- Global Environmental Management Initiative, 1990
- North Carolina Nature Conservancy Award, 1991

Duke's commitment to the environment is also reflected in the way it operates its plants. Duke's fossil-fuel plants are continually ranked as the most efficient fossil-fuel system in the nation. This greater efficiency benefits the environment by limiting the level of emissions. Duke's early awareness of its responsibility has, in many cases, enabled it to lead rather than catch up with mandated regulatory requirements.

2.1.4 Forecast Evolution

The Duke Service area forecast for peak and energy has changed substantially over the past 25 years. These changes have been brought about by influences outside the Company. These influences and their impact on Duke's forecasting methods are shown on Exhibit 2-2.

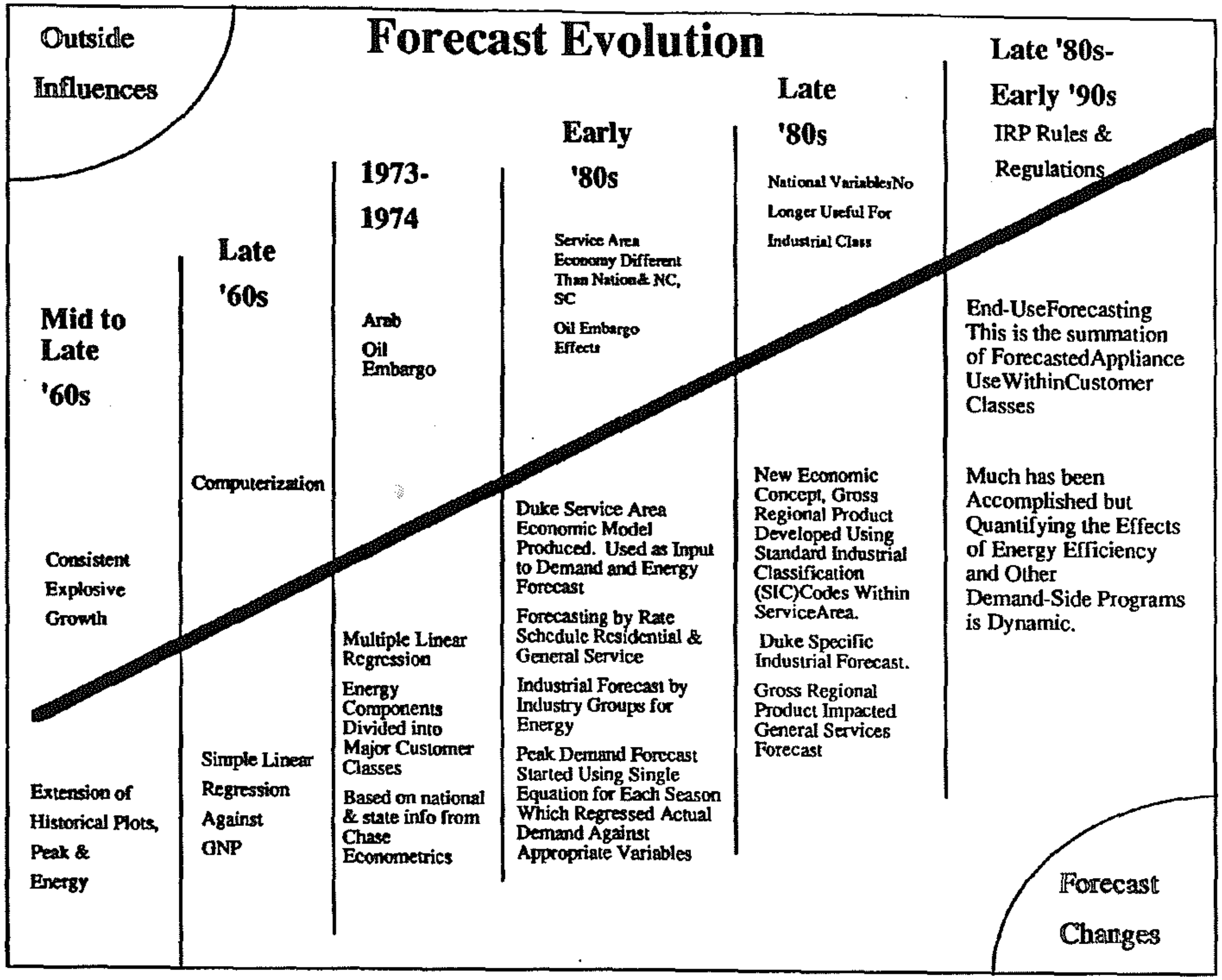


Exhibit 2-2: FORECAST EVOLUTION

2.2 Integrated Resource Plan (IRP) Regulations

Beginning in the mid 1980s, North Carolina and South Carolina regulators began the establishment of a formal system for analyzing and reporting the resources required to meet future customer needs.

2.2.1 IRP Regulations - North Carolina

The North Carolina Utilities Commission (NCUC), on March 25, 1987, issued an order instituting an investigation and rulemaking proceeding to consider the adoption of a new approach to electric utility planning called "Least-Cost Integrated Resource Planning (LCIRP)." This Order (Docket No. E-100, Sub 54) included proposed rules and directed that utilities file written comments. Integrated resource planning was enacted into law in June 1987 under North Carolina General Statute 62-2(3a).

A March 1988 order by the NCUC proposed rules defining an overall framework for the Integrated Planning process. This was followed in December 1988 by an order adopting Rules R8-56 through R8-61 for the Integrated Resource Plan (IRP).

In accordance with the newly adopted rules, Duke filed its LCIRP in April 1989. Hearings on the LCIRP were held throughout the state with the final hearing occurring in January 1990. The 1989 LCIRP was adopted by the NCUC in May 1990.

In January 1990 the NCUC Public Staff and Duke negotiated a set of stipulations to address the Public Staff's concerns about Duke's planning process. These stipulation agreements require the filing of updates as to the status of the stipulations at six month intervals. These updates were filed in November 1990 and in May and November 1991.

A separate stipulation regarding cost recovery was negotiated by Duke and the NCUC Public Staff in September 1991.

2.2.2 IRP Regulations - South Carolina

The Public Service Commission of South Carolina (PSCSC) established a generic proceeding to address integrated resource planning issues in 1987. The utilities operating in South Carolina, which includes Duke Power, and the South Carolina Department of Consumer Affairs (Consumer Advocate) and interested parties, identified issues to be addressed.

South Carolina's Rules and Regulations pertaining to the integrated resource planning process were determined through a collaborative process involving the Public Service Commission Staff, the Consumer Advocate, affected utilities, and interested parties.

An order incorporating the results of this collaborative process was issued as Order No. 91-885, Docket No. 87-223-E in August, 1991. This Order was replaced by Order No. 91-1002 to reflect minor wording changes.

The 1992 IRP will be the first report Duke will file with the PSCSC under the South Carolina rules. The 1989 LCIRP and subsequent 1990 and 1991 Short-Term Action Plans were filed with the Commission for informational purposes.

2.3 Major Developments Since the 1989 Plan

2.3.1 Rate Filings

During 1991, Duke filed its first request for a rate increase since 1986. In the rate orders issued in November 1991, the NCUC and the PSCSC allowed Duke recovery of the costs for DSM programs and allowed the deferral for later recovery of certain DSM costs that exceed the level received in rates.

In September 1991, Duke filed a request with the Federal Energy Regulatory Commission (FERC) seeking a 7.47 percent rate increase for its wholesale customers. These customers represent approximately two percent of Duke's total revenues. The proposed rates will become effective in April 1992, subject to refund pending a final decision by FERC.

2.3.2 Commercial Operation of Bad Creek Pumped Storage Hydro

The Bad Creek Pumped Storage Hydro Station was placed into service in 1991 with Units 1 and 2 being declared operational in May and Units 3 and 4 in September. The completion of Bad Creek adds 1,065 MW to Duke Power's generating capability. Bad Creek was completed approximately one year ahead of schedule for a savings of approximately $90 million. The Station is located in Northwestern South Carolina.

2.3.3 Lincoln Combustion Turbine Station (LCTS)

In 1989 Duke announced that a site in Lincoln County, North Carolina, had been selected for a new combustion turbine (CT) facility to meet customer demand in the mid-to-late 1990s. The LCTS will accommodate up to 16 CTs with a total generating capacity of approximately 1,200 megawatts of electricity. The NCUC issued an order in March 1991 granting a Certificate of Convenience and Necessity. A December, 1991 update to the 1991 Short Term Action Plan shows the first four CTs to be operational in 1995.

In December 1991, Duke was issued a final air quality permit by the North Carolina Division of Environmental Management. Commission notification and the completion of some state and local permits (normally obtained immediately prior to the start of construction) will allow Duke the opportunity to build the units when they are needed.

2.3.4 Clean Air Act

Title IV of the Clean Air Act Amendments of 1990 require electric utilities to reduce aggregate annual emissions of sulfur dioxide by 10 million tons and nitrogen oxide by 2 million tons by the year 2000. The major requirements are being phased in over two periods: the first phase begins January 1, 1995 and the second January 1, 2000. Duke currently meets all requirements of Phase I and will not have to implement changes until compliance with Phase II requirements is necessary.

Duke has historically had low emissions through the use of low-sulfur coal, through efficient operations, and by utilizing nuclear generation. Duke is currently working on a detailed compliance plan that must be filed and approved by the Environmental Protection Agency by 1995. Based on a preliminary compliance plan, the estimated costs to comply with Phase II of the requirements are expected to be approximately $1 billion in capital expenditures and approximately $81 million annually in operating and maintenance expenses. These costs are stated in year 2000 dollars.

Title I may require modifications at some stations for Nitrogen Oxides control by 1996, pending state compliance plans. Refer to Section 4.3.1 for further explanation.

2.3.5 Nuclear Steam Generators

Stress corrosion cracking (SCC) has occurred in steam generators of a certain design, including those of the McGuire and Catawba Nuclear Stations. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2, and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC will be a problem.

Although Duke has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists, and it is difficult to predict the extent to which future remedial measures will be required. SCC has necessitated that the company plan for the replacement of steam generators at McGuire Units 1 and 2, and Catawba Unit 1. Although the sequence and schedule for the replacement of the steam generators has not been established, the Company anticipates beginning replacement as early as 1995, with completion of all three units as early as the end of 1997.

Duke, in connection with its McGuire and Catawba Stations and on behalf of the other joint owners of the Catawba Station, commenced an action on March 22, 1990 that alleges Westinghouse Electric Corporation (Westinghouse), the supplier of the steam generators knew, or recklessly disregarded information in its possession, that the steam generators supplied to the McGuire and Catawba Stations would be susceptible to SCC and that Westinghouse deliberately concealed such information from Duke. Duke is seeking a judgment that Westinghouse is obligated to correct the defects in the steam generators at no cost to Duke. The judgment would include payment for replacement power during the extended outages to accomplish the repairs and replacements, and for punitive damages related to the fact that Westinghouse concealed this information.

For information on the effect of Steam Generator outages on the 1992 Integrated Resource Plan, see Section (4.3.1).

2.3.6 Integrated Resource Planning Advisory Panel

Panel Origination

Stipulation F.1, agreed to by Duke and the NCUC Public Staff and approved by the NCUC in the May 17, 1990 order, called for Duke to formalize public involvement in the IRP process. In respone to that Stipulation, Duke initiated the IRP Advisory Panel in June 1991 to receive technical guidance, opinions and recommendations from experts outside the company. The Panel consists of nine members representing local expertise in the areas of business, industry, education, and customer and environmental concerns. Panel members were chosen from a list of candidates that were selected from recommended candidates that have expertise in one of the designated areas and have shown an interest in Duke's activities. Candidates who were obligated through professional associations to represent certain positions were excluded from consideration, but those with views different from -- or even counter to -- the Company were intentionally included. Ultimately, Duke selected a panel that was open to ideas but could bring diverse views to the table. The group, however, does not replace Duke's customer-focus groups, which are used to obtain input and feedback on customer service issues. Panel members live within Duke's service area and are Duke customers. Members serve for a minimum of one year. The current group was asked to serve from June 1991 through December 1992 as an initial term.

Representatives of the Supply-Side, Demand-Side, and Integration Teams -- as defined in Process Overview (3.0) -- participate in the Panel meetings to provide information, answer questions and receive the Panel input. Duke's representatives include: the Vice-President, Generation Services Department who chairs the Supply-Side Team; Vice-President, Customer Planning Department who chairs the Demand-Side Team; and Vice-President, System Planning and Operating who chairs the Integration Team.

Meetings

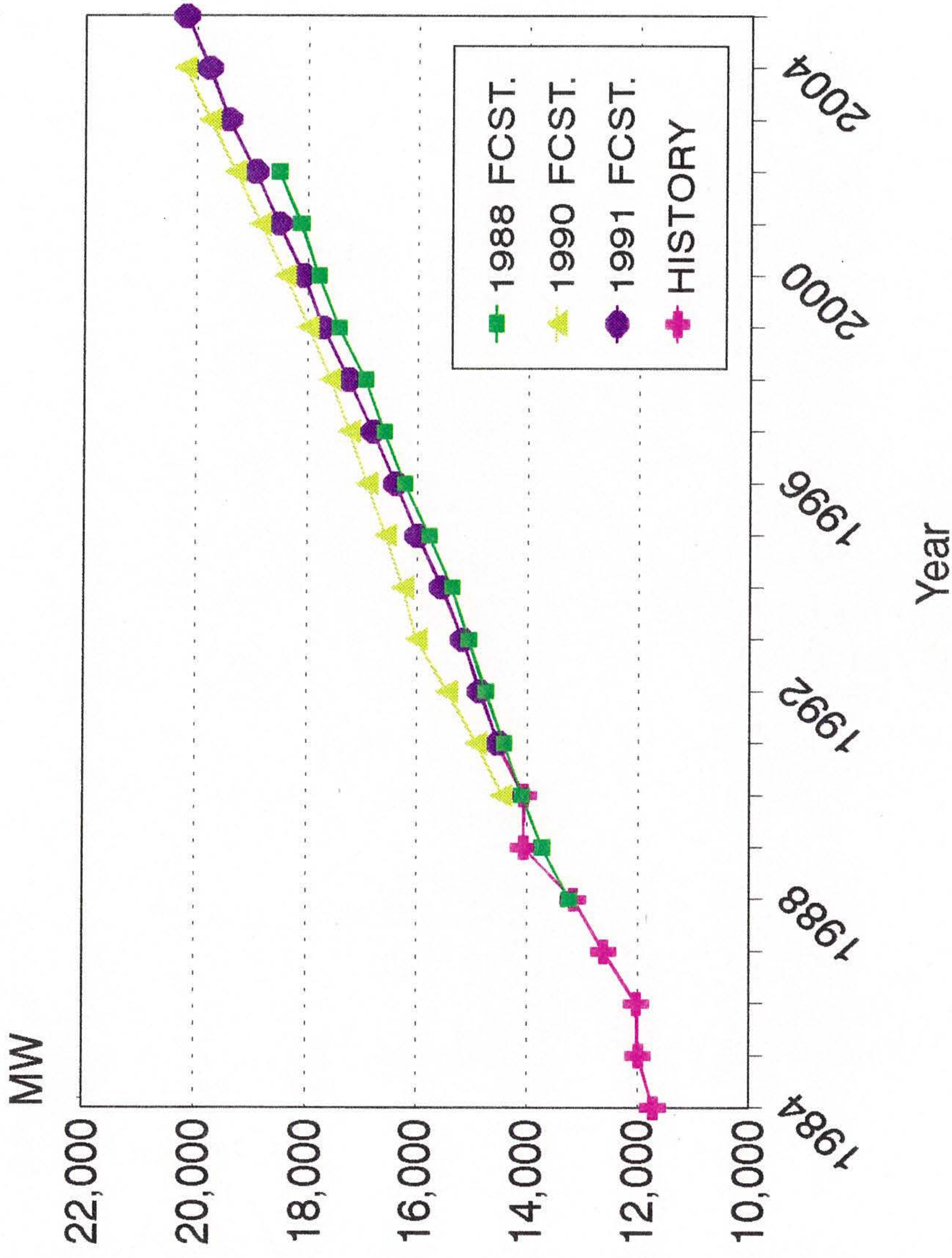
Three meetings were held in 1991 to orient the Panel to Duke's IRP process and results. Issues such as environmental externalities and demand-side bidding were presented to the Panel. The Panel offered suggestions and comments on individual demand-side programs and opinions on issues impacting the IRP process. Six meetings are scheduled during 1992 for the Panel to provide technical guidance and recommendations on the IRP process, plan and issues. Specifically, in 1992, the Panel has reviewed Duke's Request for Proposal for a demand-side bidding pilot program, a draft of the 1992 IRP, and Duke's proposed strategy on environmental externalities. The Panel will address other issues in future meetings. Based on early experience, Duke believes the Panel will be a positive and helpful addition to the planning process. Panel recommendations are documented and considered by Duke in the IRP process. Annual reports will be prepared to document the Panel's activities, recommendations, and Duke response. The first report will be prepared following the June, 1992 Panel meeting.

Appendix II-2 contains the Panel guidelines and additional details on the meetings.

2.3.7 Forecast Comparison To Date

The forecast used in the 1989 LCIRP was adopted in May 1988. The next forecast was adopted in January 1990. This forecast was presented in both the 1990 and 1991 Short Term Action Plans and showed an increase in all years when compared to the May 1988 forecast. This increase was attributable to strong and persistent growth in summer peak demand. The forecast used in this planning process was adopted in May 1991 and is lower than the January 1990 forecast. There are several reasons for the lower forecast: the recession of 1990-91; the lower expected long-term rate of industries moving into the service area, and the realization of slower housing construction due to demographic trends. A further discussion of these factors is included in section 5.1. A summary of these forecasts are shown on Exhibit 2-3.

Exhibit 2-3: COMPARISON OF SUMMER PEAK FORECAST



2.4 Objectives

2.4.1 Integrated Resource Planning Objectives

Both North Carolina and South Carolina have stated clear objectives in formalizing the integrated planning process.

The purpose of integrated resource planning as stated in the North Carolina Rules and Regulations is "...to ensure that each regulated electric utility operating in North Carolina is developing reliable projections of the long range demands for electricity in its service area and a combination of reliable resource options for meeting the anticipated demands in a cost effective manner."

The South Carolina Order states that "The objective of the IRP process is the development of a plan that results in the minimization of the long run total costs of the utility's overall system and produces the least cost to the consumer consistent with the availability of an adequate and reliable supply of electricity while maintaining system flexibility and considering environmental impacts."

Duke believes that through its planning process the objectives of both states are met or exceeded.

2.4.2 Goals and Objectives of the 1992 IRP

The goal of Duke Power Company's 1992 Integrated Resource Plan (IRP) is to ensure that through the use of a combination of reliable resource options, the anticipated demands of Duke Power's service area will be met at a minimum cost to consumers. Duke has long been known as a world leader in generating efficiency. We now have the opportunity to become known in the future as the company with the most efficiently generated "and consumed" electric energy in the world.

Recognizing that any plan that projects 15 years accepts a myriad of risks, large and small, Duke's 1992 IRP has addressed the widest range of resource options to provide the highest degree of flexibility. This critical factor will allow Duke to meet these future uncertainties to both take advantage of the unforeseen positive factors and amelioriate the unforeseen negative forces.

Meeting Customer Needs

Duke's customer mix contains an unusually high percentage of industrial customers who must compete on both national and international fronts. It is important that the planning process result in electricity costs and options which will be reliable and allow industrial customers to remain competitive. Commercial and residential customers are also interested in electricity costs that are competitive and demand-side programs that provide savings, flexibility and reliability.

Meeting Environmental Concerns

Consistent with Duke's longstanding concern for the environment, the planning process considers the environmental impact of resource decisions and incorporates the cost of meeting environmental regulations in its assessment of resource options.

Maintaining Shareholder Value

Resources must be selected and implemented in such a way as to minimize economic, operational and regulatory risks while maintaining appropriate earnings.

2.4.3 Current Key Issues Facing Duke

Lincoln Combustion Turbines: An issue facing Duke is when to start construction consistent with integrated planning needs. Another issue affected by the timing of construction is that Duke has negotiated favorable prices for the turbines. This represents a significant cost savings which is available for a limited time.

Plant Modernization Program (PMP): Five remaining fossil units are scheduled to be returned to service under the PMP. The key issue is the optimum timing for the return to service of these units considering cost, capacity, and energy needs. See Section 4.4 for additional details.

Steam Generators: Duke faces the probable need to replace the steam generators in both units of the McGuire Nuclear Station and Unit 1 of the Catawba Nuclear Station. This situation is not a safety concern, so the critical aspect of this decision is to replace the generators at a time that will incur the least impact on the operation of the system. See Section 2.3.5 for additional details.

Catawba Transfer: Duke is in various stages of negotiation with the co-owners of the Catawba Nuclear Station regarding the terms and conditions for the possible transfer and replacement of a portion of the co-owner's project capacity and energy off the Duke system. The actual timeframe of any such transfer(s), if ultimately agreed upon by all parties, is not currently known but would not commence until the mid 1990's.

Demand-Side Programs: Duke must continually evaluate the effectiveness of existing Demand-Side programs as well as the timing and market penetration of new programs. In addition, it is not currently known how much DSM capacity and energy savings can be sustained over time.

2.4.4 Future Key Issues Facing Duke

Base Load Unit: Duke is not faced with determining a base load generating technology, optimum unit size or firm construction date during the next three years. Demand-side programs and/or combustion turbines, which require less time for implementation, will provide the necessary resources to meet customer needs.

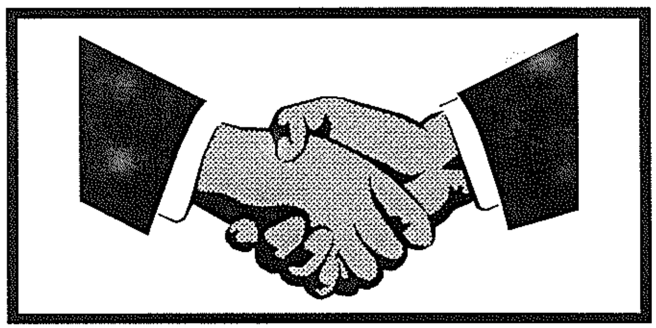
Generation Replacement Study: As the existing 18,000 MW system ages it is imperative that a determination be made whether this capacity can reliably and economically carry

Duke through the planning horizon. This determination would include environmental and regulatory concerns. Although demand-side programs have been determined to be cost effective in meeting future customer requirements, system voltage support was assumed to be supplied by the existing system. Refer to Section 4.3.1 for additional details.

Clean Air Act: Duke currently meets all requirements of Title IV Phase I of the Clean Air Act to become effective January 1, 1995. Phase II compliance with Title IV is not required until January 1, 2000. A study team is determining what Duke must do to comply with the Phase II requirements. See Section 2.3.4 for additional details.

Station Retirements: As a result of the Plant Modernization Program and the continued need for the existing generation capability, there are no anticipated retirements of generating capability during this integrated planning process. However, retirements are anticipated beyond the 2006 planning horizon.

Integrated Resource Planning
at
Duke Power Company



Presented to:
The Southeastern Power Administration
Integrated Resource Planning Conference

Columbia, South Carolina
May 29, 1992

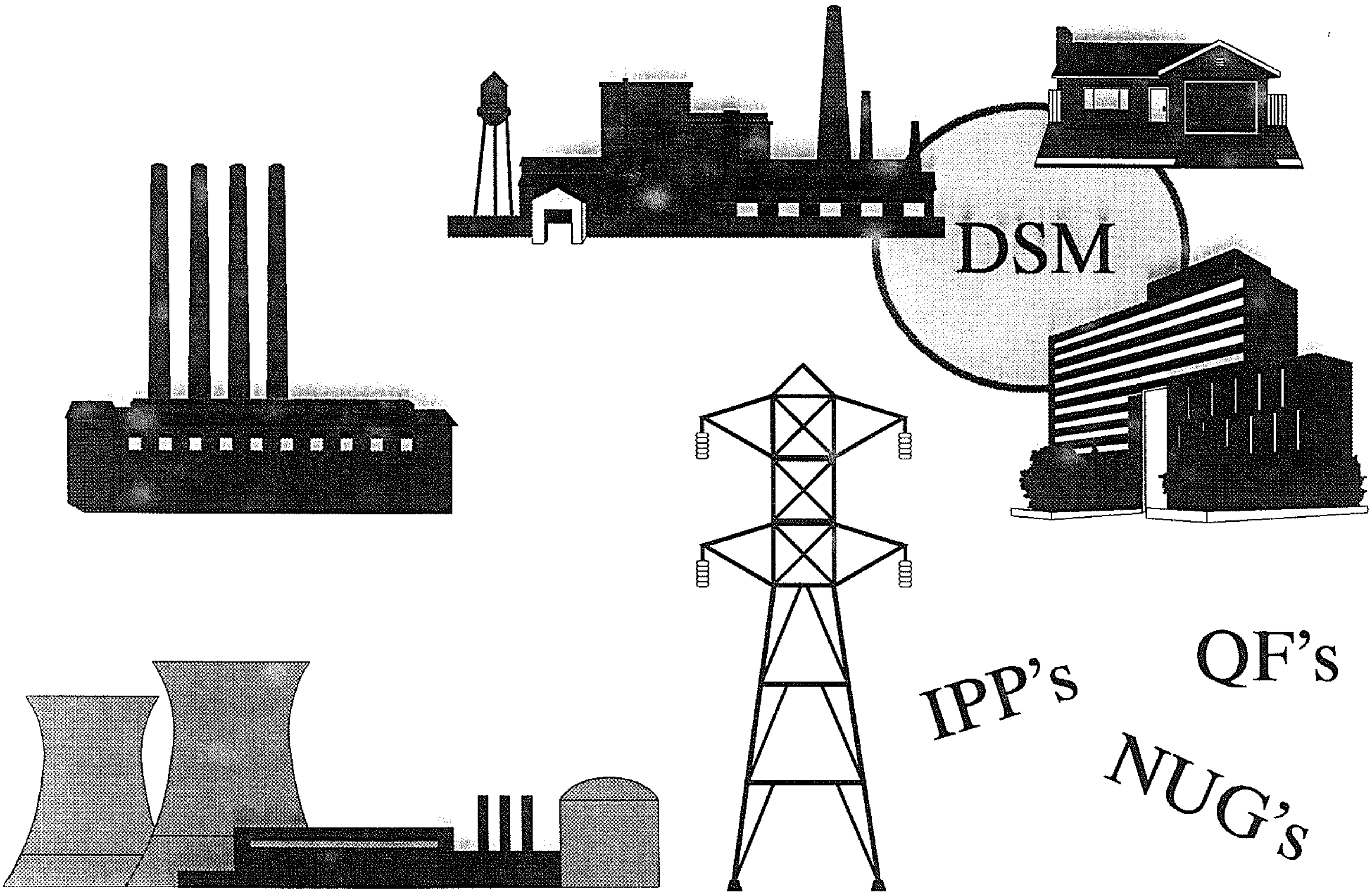
AGENDA

- IRP Objective
- Process Overview
- Resource Integration
- Risk Assessment
- Integrated Resource Plan

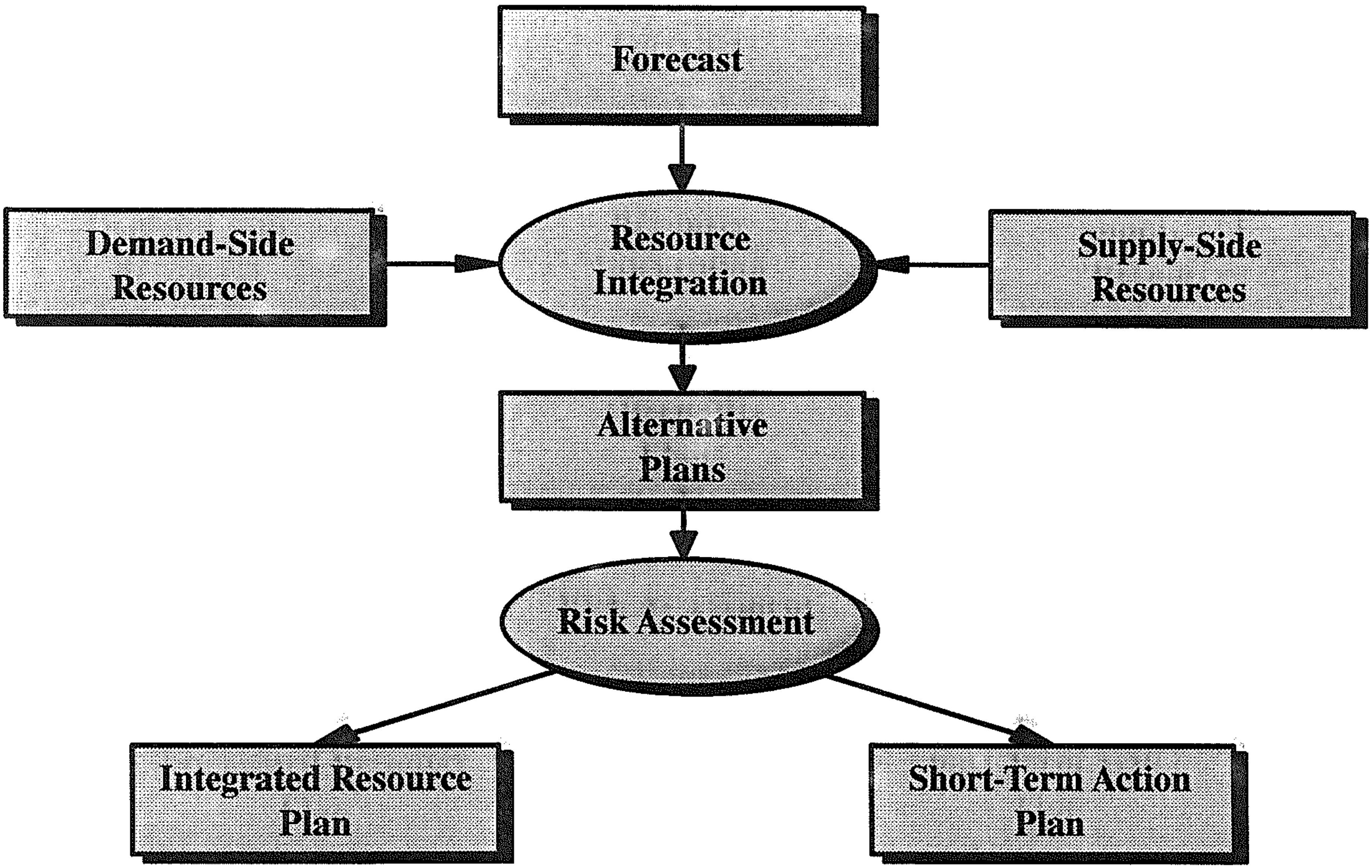
The Objective of Duke's IRP is to ...

Develop a plan which minimizes long run total costs consistent with the availability of an adequate and reliable supply of electricity with consideration of environmental impacts, energy efficiency and uncertainties.

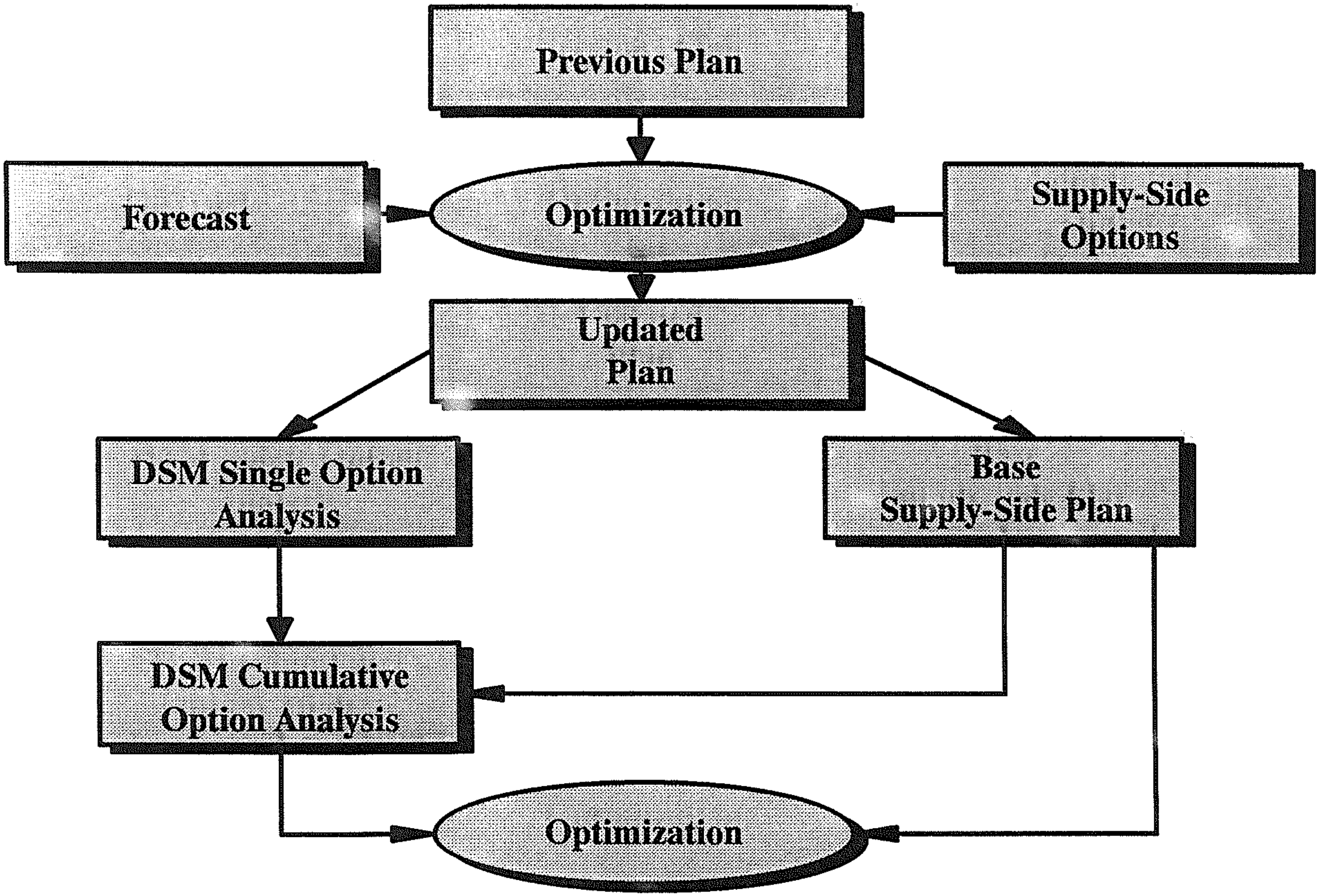
All Resource Options are Considered



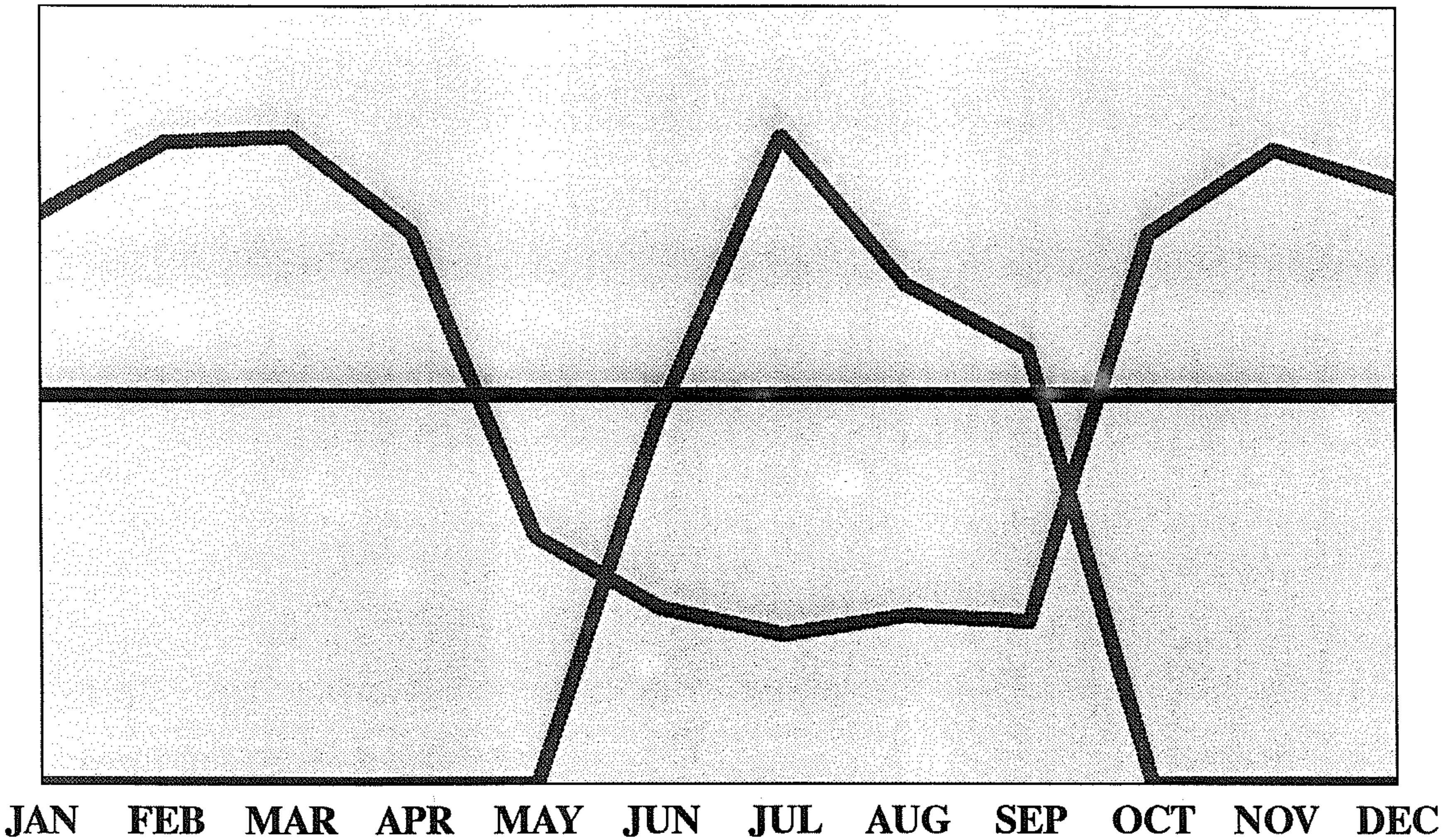
IRP Process Overview



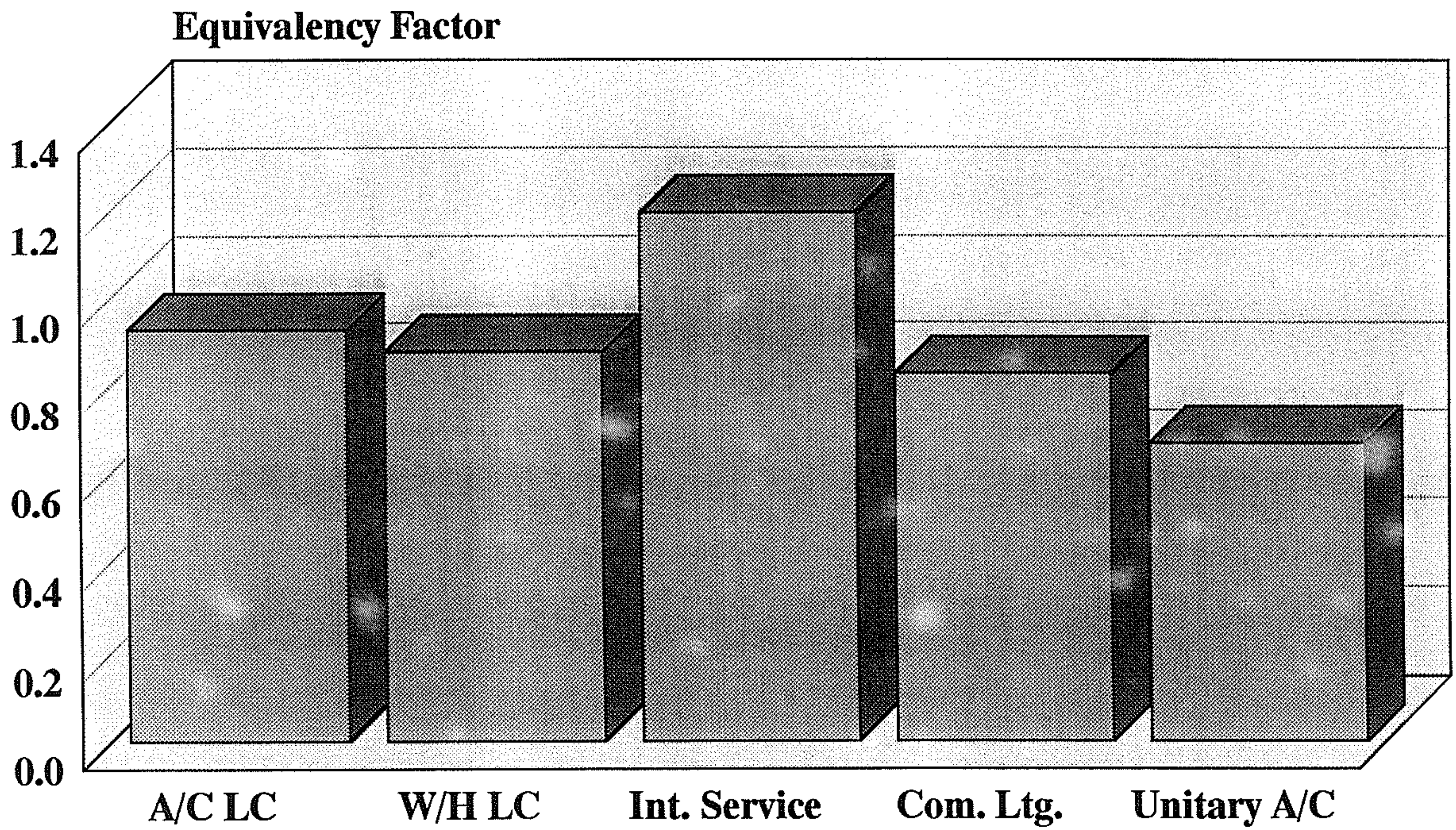
Resource Integration



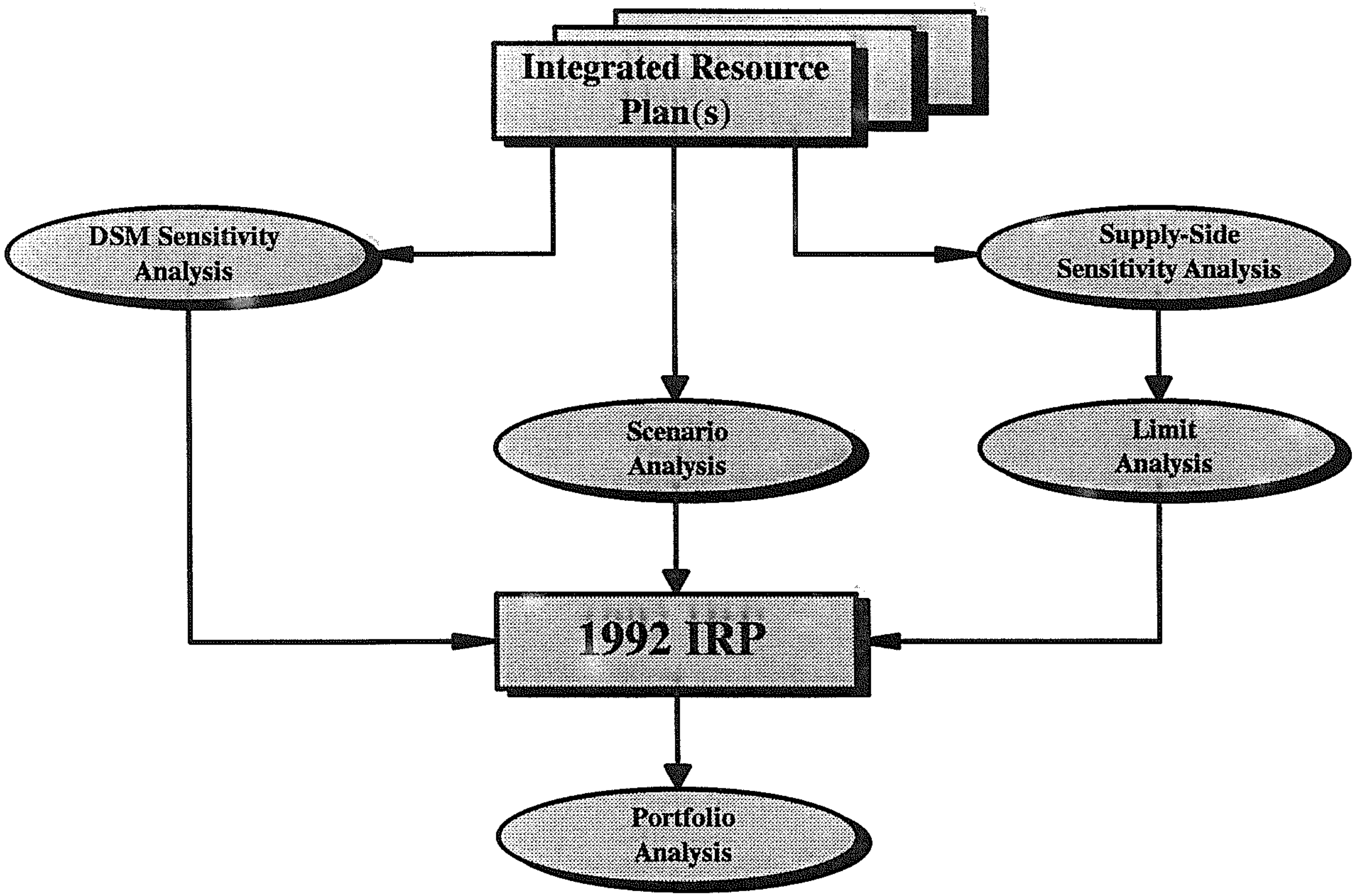
DSM Resources Have Varying Impacts on System Load Shape



DSM Load Shape Impact Determines Equivalency



Risk Assessment

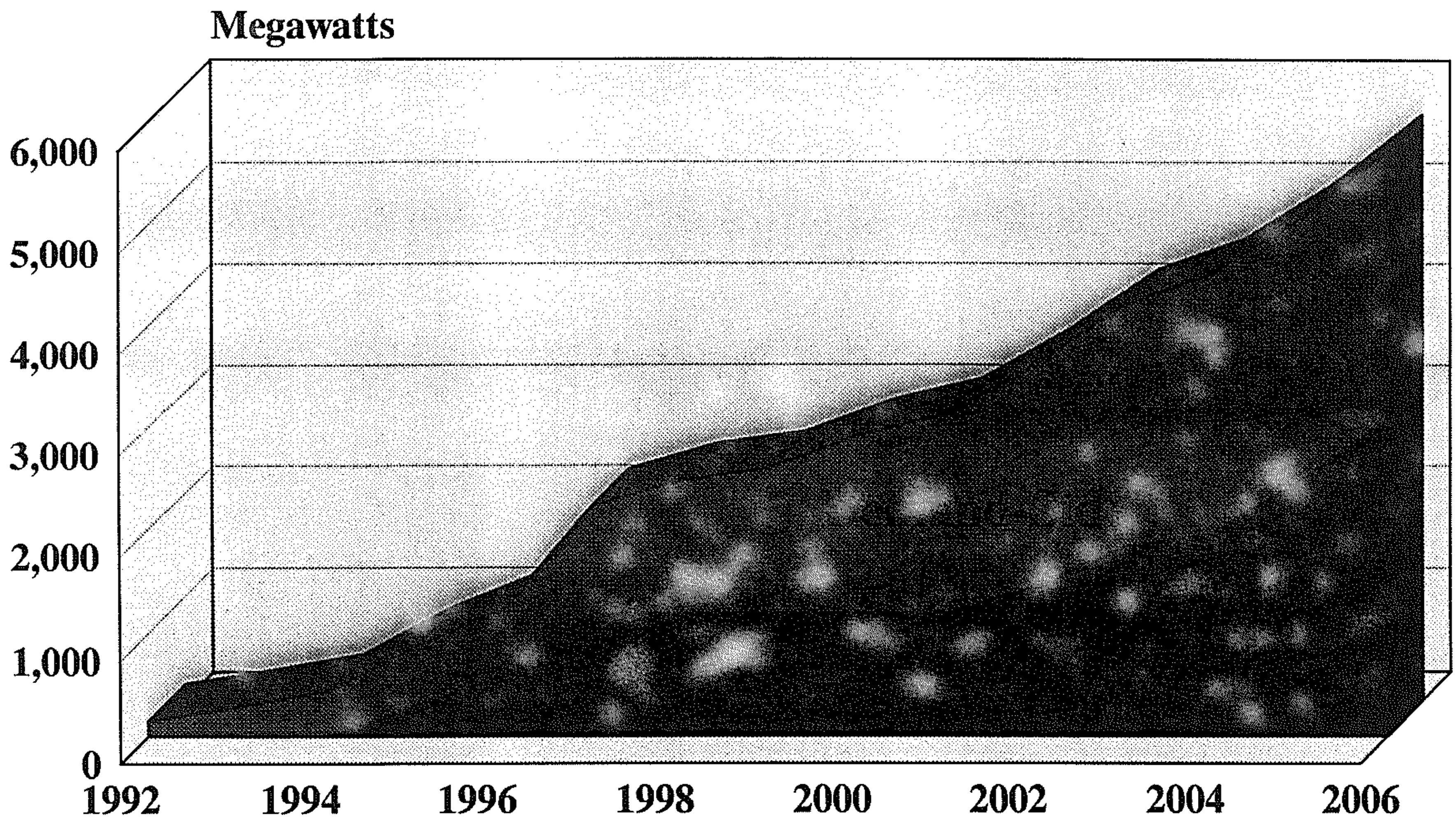


Duke's 1992 IRP

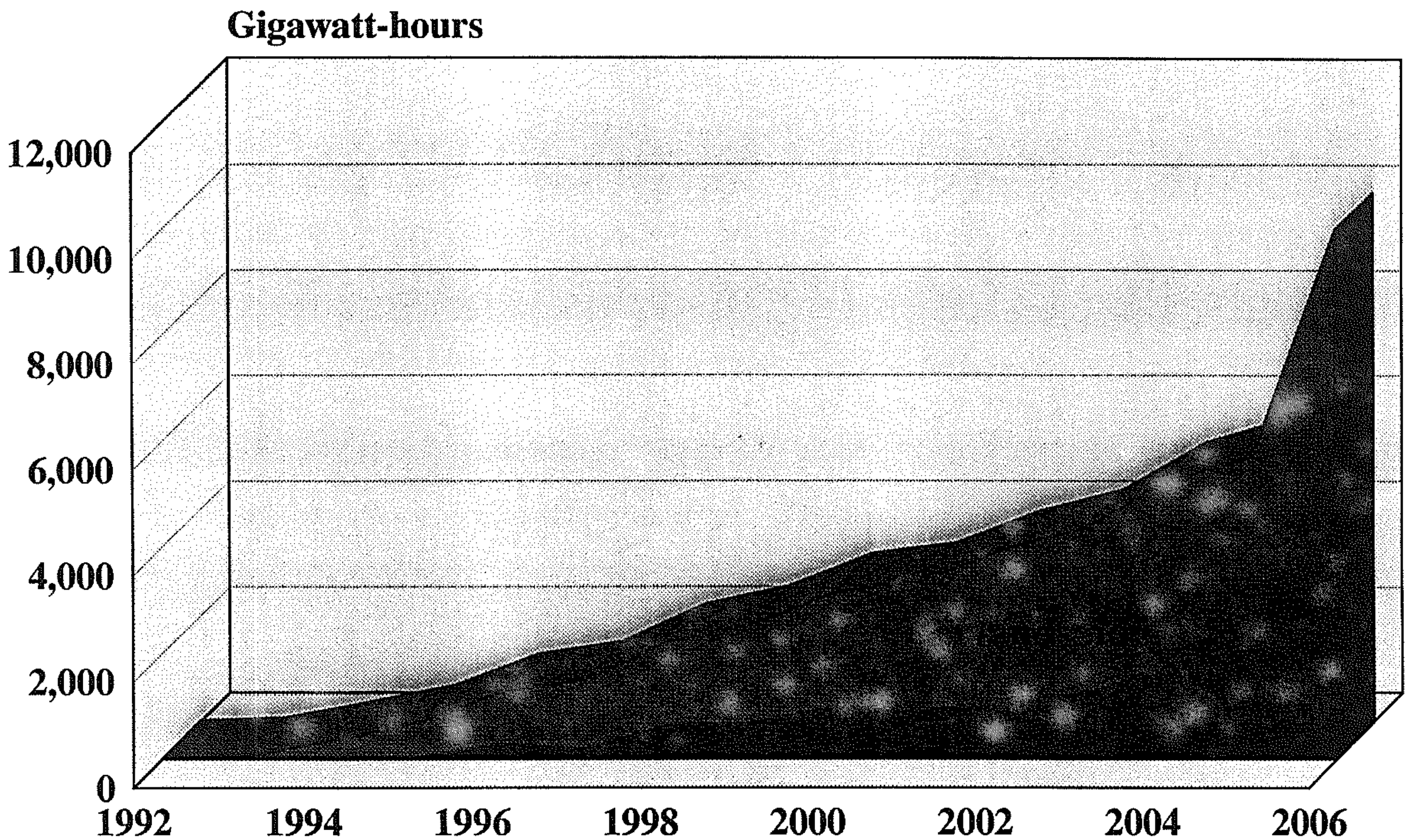
Capacity Additions (MW's)

Year	CT's	Coal	DSM
1992			149
1993			140
1994			154
1995	296		140
1996	296		42
1997	592		424
1998			248
1999			118
2000			319
2001			208
2002	256		236
2003	384		209
2004	128		179
2005	512		29
2006		600	78

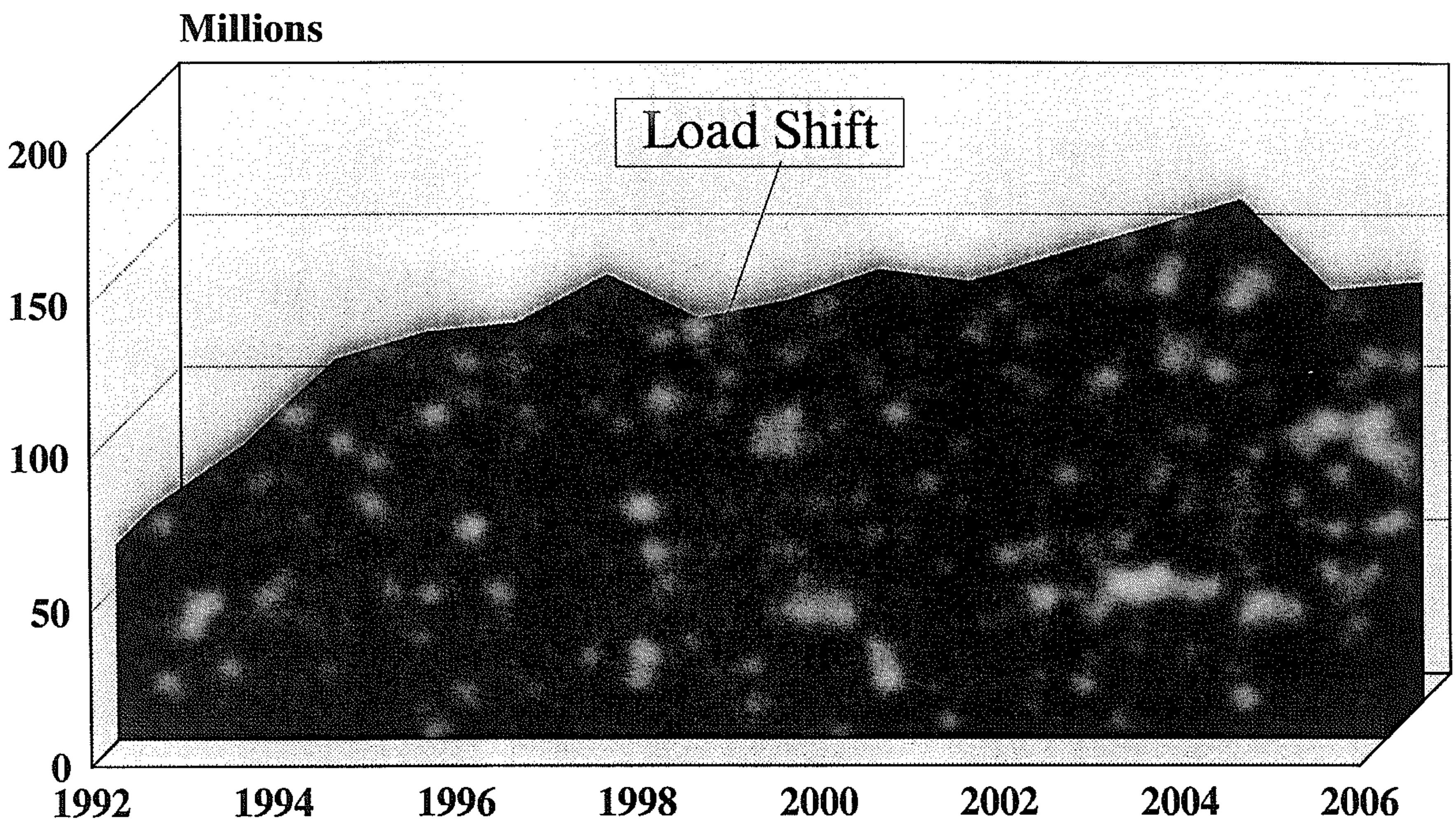
DSM Accounts for 47% of Capacity Resource Additions

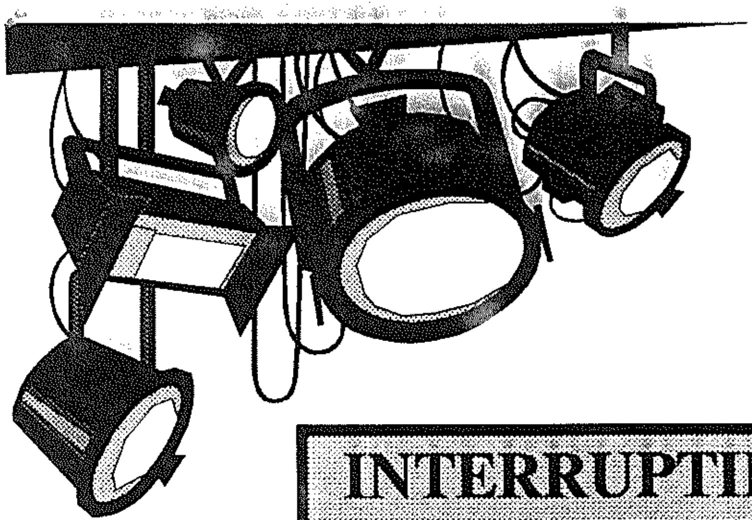


DSM Accounts for 64% of Energy Resource Additions



DSM Annual Expenditures





DSM Programs

INTERRUPTIBLE

A/C Load Control
W/H Load Control
Standby Generator
Interruptible Service

LOAD SHIFT

Off-Peak W/H

ENERGY EFFICIENCY

Residential Heat Pumps
Central Air-Conditioning
Freezers
Refrigerators
W/H Blankets
Insulation
HVAC Tune Up
Chillers
Unitary Air-Conditioners
C/I Lighting
Motor Systems

3.0 PROCESS OVERVIEW

3.1 Introduction

Duke Power's integrated planning process is complex and involves an array of computer models and human resources. Integrated planning has been performed by Duke for many years with continual changes and improvements. The Integrated Resource Plan (IRP) regulations in both North and South Carolina have resulted in a formalization of the process. This section will describe the overall integrated planning process as it was carried out in the preparation of this IRP filing. The sections in this document devoted to Forecasting, Demand-Side Resources, Supply-Side Resources, Purchased Resources, Integration and Risk Assessment each have a Process Overview which links it to other sections and describes the part it plays in the planning process.

3.2 The Team Approach

The integrated planning process uses three teams, representing the three major functional areas (Demand-Side, Supply-Side, and Integration) involved in the planning process. It is the responsibility of these teams to assure the consistency and reliability of data and assumptions, review and refine modeling methods used and examine the results. Each team includes representatives from the three functional areas, plus Purchased Resources, to assure consistency and continuity. These teams and their primary focus are:

Demand-Side Team - This team identifies and develops information and guidelines for energy efficient, load shift, interruptible, and environmental resources. All option development, data collection, and analyses for these options are reviewed by this team.

Supply-Side Team - This team develops guidelines for creating a menu of generation options available to the Duke system. In addition, this team has the responsibility for supply-side costs, schedules, performance data and screening analyses for these generation options.

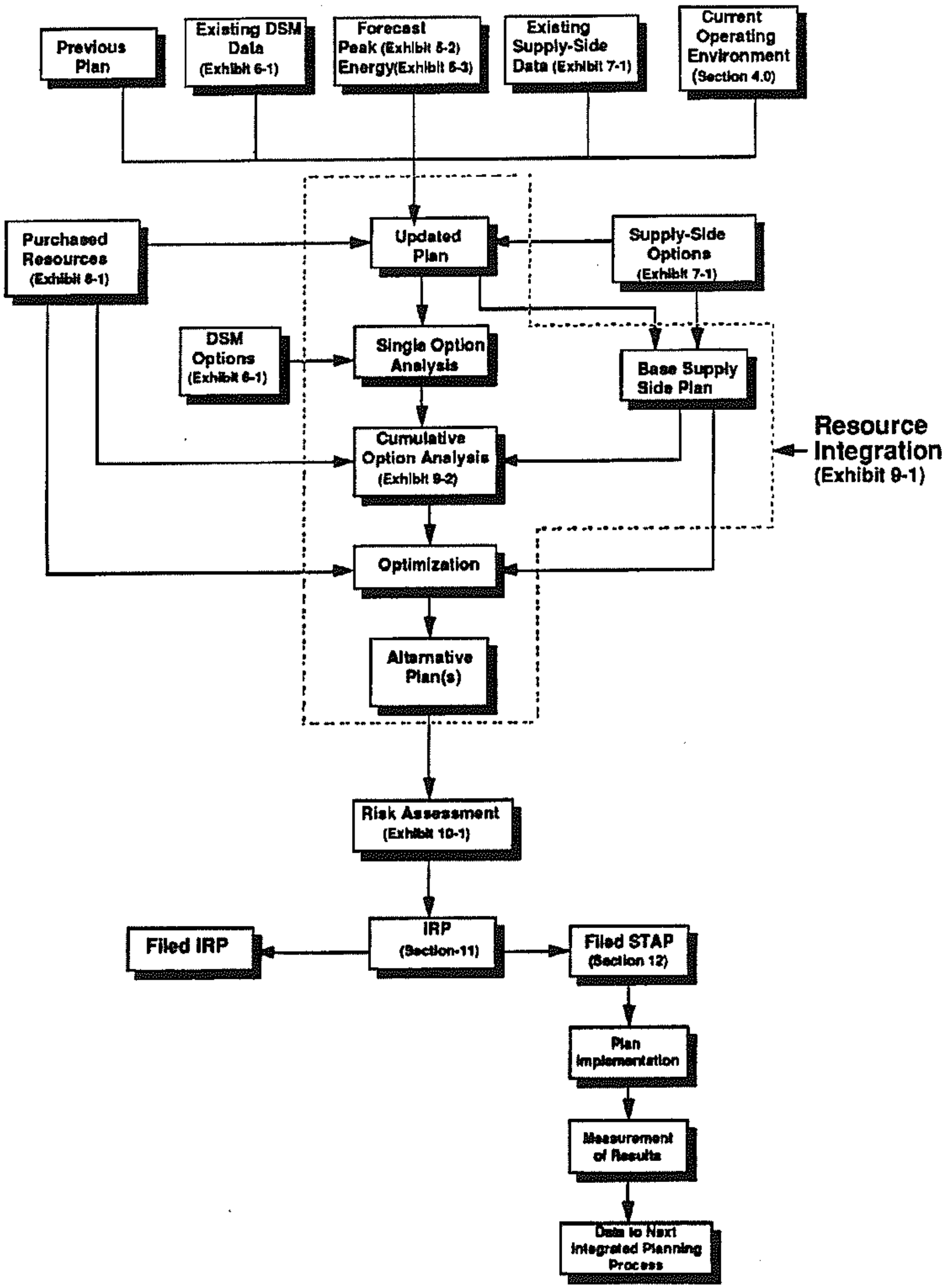
Integration Team - This team has the responsibility of combining information developed from demand-side resources and supply-side resources with information on purchased resources to produce an integrated resource plan.

The Integrated Resource Planning Advisory Panel, which is described in Section 2.3.6 is kept informed throughout the integrated planning process. The panel members are given the opportunity to comment and make recommendations on all aspects of the process.

3.3 The Integrated Planning Process

Exhibit 3-1 shows a flow-chart overview of the integrated planning process. Included are exhibit number references to more detailed process overview charts in the other sections.

Exhibit 3-1: INTEGRATED PLANNING PROCESS



The development of a peak and energy forecast for Duke's service area is considered as the starting point for the integrated planning process. This forecast, which is completed in the spring of each year, begins with the development of the service area economic model

(Exhibit 5-1). Economic data from government and private organizations are utilized to produce four groups of economic indicators:

- Inflation adjusted gross regional product
- Inflation adjusted total and disposable personal income
- Employment
- Inflation adjusted price of electricity

These indicators serve as the primary inputs into the Peak Demand Models (Exhibit 5-2) which produce winter and summer peaks and the Energy Models (Exhibit 5-3) which produce residential, general service and industrial energy requirements.

The identification and analysis of DSM options, as described in Demand-Side Resources (6.0) and supply-side options, as described in Supply-Side Resources (7.0), occur at approximately the same time. These options are utilized by the Resource Integration process.

DSM options can take the form of load shift, interruptible, environmental and energy efficiency. The options can come from the review of technologies and the revision of existing programs. A wide array of resources, as shown in Exhibit 6-1, are utilized in developing new DSM options. A computer model (DSManager) is used to review and optimize the various options before passing them to Resource Integration. Some options are piloted in order to obtain additional information or are held for future consideration.

Supply-side options also originate from the review of new and existing technologies. The options that are viable in Duke's service area are evaluated based on: the amount of time to bring into operation; the cost to build, operate and maintain the option; and operating characteristics. Based on these factors, a screening curve technique is used to determine the present worth of revenue requirements for each option without consideration to their interactions with the existing generation system. Options selected by this analysis are then passed to Resource Integration.

Purchased Resources are evaluated throughout the year as purchased resource options become available. The value of an option will be determined by economic and technical viability screening. Operating characteristics and the cost of integrating the option into Duke's system is then evaluated and a net economic benefit calculated. Contract negotiations are initiated on options with positive net economic benefit. Those options successfully negotiated are incorporated into Resource Integration.

Resource Integration consists primarily of these five processes:

Updated Plan: The previous integrated resource plan is updated by incorporating the new peak and energy forecasts, DSM, purchased power and system operating information. This information is optimized, resulting in an Updated Plan.

Base Supply Side Plan: Supply-Side Options are input into an optimization planning model (PROVIEW) to determine an optimal Base Supply-Side Plan. This plan is used to update supply-side information for use in the Cumulative Option Analysis and Optimization.

Single Option Analysis: DSM options are compared one at a time against the Updated Plan to develop an economic ranking for Cumulative Option Analysis.

Cumulative Option Analysis: The Single Option Analysis results are used to analyze the DSM options cumulatively by adding one option at a time in ranked order. The production and capacity impacts along with the financial data associated with the option result in the computation of a benefit/cost ratio. These results are then used in the development of alternative plans.

Optimization: The final step in the integration process is to optimize: the benefit/cost ratios from Cumulative Option Analysis; the supply-side technologies from the Base Supply-Side Plan; and any additional purchase agreements into one or more alternative plans. These alternative plans are then used in Risk Assessment.

Risk Assessment, as shown in Exhibit 10-1, consists of the combination of four analytical techniques:

Sensitivity Analysis: The determination of the effect (sensitivity) of changing one key DSM or Supply-Side assumption in the alternative plan(s). Many key assumptions are changed, one at a time, during Sensitivity Analysis with different models used depending on the key assumption changed.

Limit Analysis: The use of multiple combinations of key planning assumptions in order to determine a range of possible future outcomes. The plan which shows the lowest cost over this wide range of possible future outcomes is used in development of the IRP. (See Exhibit 10-2)

Scenario Analysis: Several different expansion plans are constructed and reviewed with certain aspects of the scenarios reviewed in detail. Scenarios are developed to analyze the interaction between various levels of achievement in DSM resources and the resulting supply-side expansion plan. Each of the plans are then compared to determine the capacity and energy mix of demand and supply options, the average cost to provide energy to meet customer needs and the impact on air emissions.

Portfolio Analysis: Determines if the resources included in the IRP have a significant impact on the cost of electricity as compared to those costs used to develop the forecast. This "closes the loop" on the planning process. (See Exhibit 10-3)

This Plan and its associated Short-Term Action Plan are then filed with the North Carolina Utilities Commission and the Public Service Commission of South Carolina. DSM programs are evaluated and costs accumulated to determine the effectiveness of the programs. This information becomes part of subsequent integrated planning processes.

4.0 CURRENT OPERATING ENVIRONMENT

4.1 Introduction

This section describes the current operating resources and customer trends.

Customers of the future will differ in many ways from customers of today. The characteristics of today's customers and the probable characteristics of future customers must be examined before options to meet their needs can be developed.

A plan for the future cannot be made without first evaluating generation, transmission and distribution resources that are currently available and those that are expected to be available throughout the planning period. Both internal and external factors limiting the future availability of these resources must be considered. Firm commitments for the addition of generation, transmission and distribution resources, as well as firm commitments for power purchases and sales with entities outside Duke's service area, must be taken into account.

This section will provide a better understanding of today's customer and what future customers are likely to want and need. In addition, Duke's available and scheduled resources will be described.

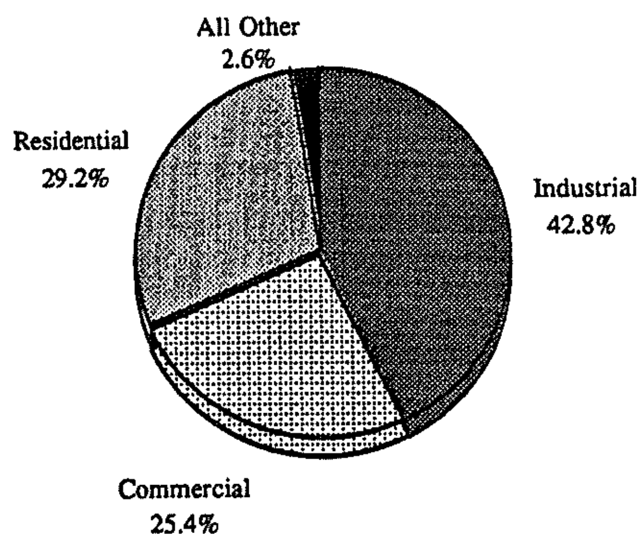
4.2 Customer Overview

4.2.1 Current and Short-Term Customer Trends

A graph showing the percentage of Duke sales by customer class in 1991 is shown on Exhibit 4-1.

The most prominent customer trend in the Duke service area is the declining ratio of energy sales to the industrial class of customers. Energy sales to the industrial class comprise approximately 43 percent of total energy sales. Within this class of customers the major user of electricity is the textile industry. Textile industry energy sales make up 43 percent of total industrial sales. This share has been declining as other industries have moved into the service area. Industries which have experienced growth include non-electrical machinery, rubber and plastics, paper and food products. During the next few years the textile's share of total energy sales is expected to decline.

Exhibit 4-1: PERCENT KWH SALES BY CUSTOMER CLASS - 1991



The fastest growing group of customers is the commercial or general service customer class. As Charlotte has become a major banking center in the nation, many financial and professional business services have moved in Duke's service area. In addition, many industries have located new plants in the area, and commercial support businesses soon followed. Although growth in the commercial class of customers has slowed due to the recession, growth of energy sales to this customer class should lead that of any other customer class.

The residential customer class is influenced by demographic factors. The predominant demographic factor in this class is the aging of the population as "baby-boomers" grow older. As will be discussed later, the generation following the "baby-boomers" will be smaller in number. It is also widely accepted that the aging "baby-boomers" will not have the buying power of their counter-parts one generation ago. As a consequence, the rate of new housing construction is not expected to grow as quickly as in the 1980s which implies the rate of growth of energy sales to the residential class should be the slowest of all classes.

4.2.2 Demand-Side Program Implications

Both the industrial and commercial classes are involved in what could be termed "productivity improvement" processes. Part of productivity improvement involves decreasing costs of operation. This implies that the most attractive demand-side management programs for these customers could be those offering the quickest return on their investment.

In the residential class, programs that enhance convenience at a reasonable cost should be most attractive. Also, since the older "baby-boomers" will have reduced buying power, this class of customers will be attracted to programs offering the quickest return on their investment.

4.2.3 Long-Term Observations

Overall, the expectation for the long-term is that our region will experience slower growth than it has historically. The first reason for this is an expected slower movement of manufacturing industries into the service area due to more regional competition and an increasing regional wage rate relative to the nation.

Second, the "baby-boomers" are aging. During the early 1980s this segment of society postponed purchasing "big ticket" items due to high interest rates. When the recovery occurred during the middle 1980s, this segment entered the housing and all consumer markets with a fury. The result was one of the longest peace-time recoveries in the history of the nation. This recovery started to stagger in 1989 and the expectation for the 1990s is that the group replacing the "baby-boomers" for new housing will not have neither the numbers nor the buying power to make the economic impact of the "baby-boomers". This decline in the growth of housing needs will lead to slower economic growth.

The third reason for slower growth during the 1990s is the relatively high debt levels of consumers, businesses and government. During the long-term horizon, these three will be reducing their debt which will lead to a reduction in the level of growth through decreased consumption and investment. Prior consumption and investment expenditures will be replaced by debt-retirement. These historically high debt levels will not be reduced instantly. This higher debt will lead to higher-than-natural real interest rates, which will tend to keep consumers and businesses from borrowing money. A comparison of forecasted service area and national growth indicators for the period 1990-2005 is shown on Exhibit 4-2.

Exhibit 4-2: NATIONAL VS. SERVICE AREA GROWTH INDICATORS 1900-2005

	Service Area	National
Real Gross Product	2.5%	2.4%
Real Personal Income	2.9%	2.2%
Employment	1.8%	1.4%

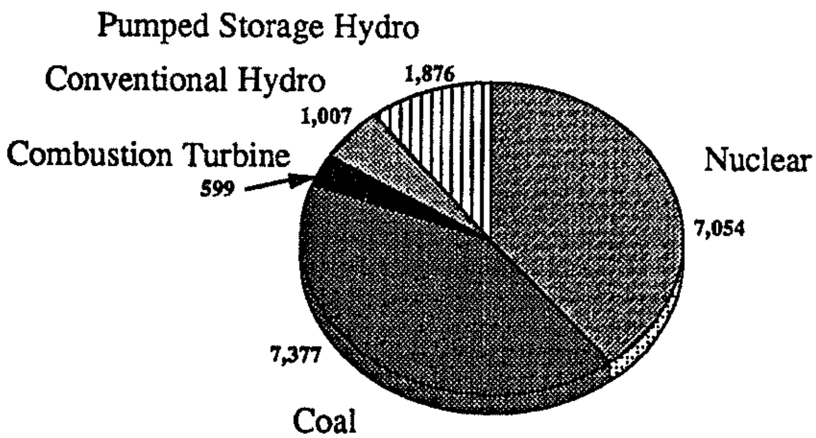
4.3 Existing Resources

4.3.1 Generation Resources

Generating Capacity

Duke's total generating capacity (excluding Nantahala Power and Light) for 1992 is 17,913[1] Megawatts (MW). This capacity is the amount of electricity available from all units under adverse operating conditions, normally due to lost efficiency arising from cooling requirements during hot summer periods. This capacity is shown by type of generation in Exhibit 4-3.

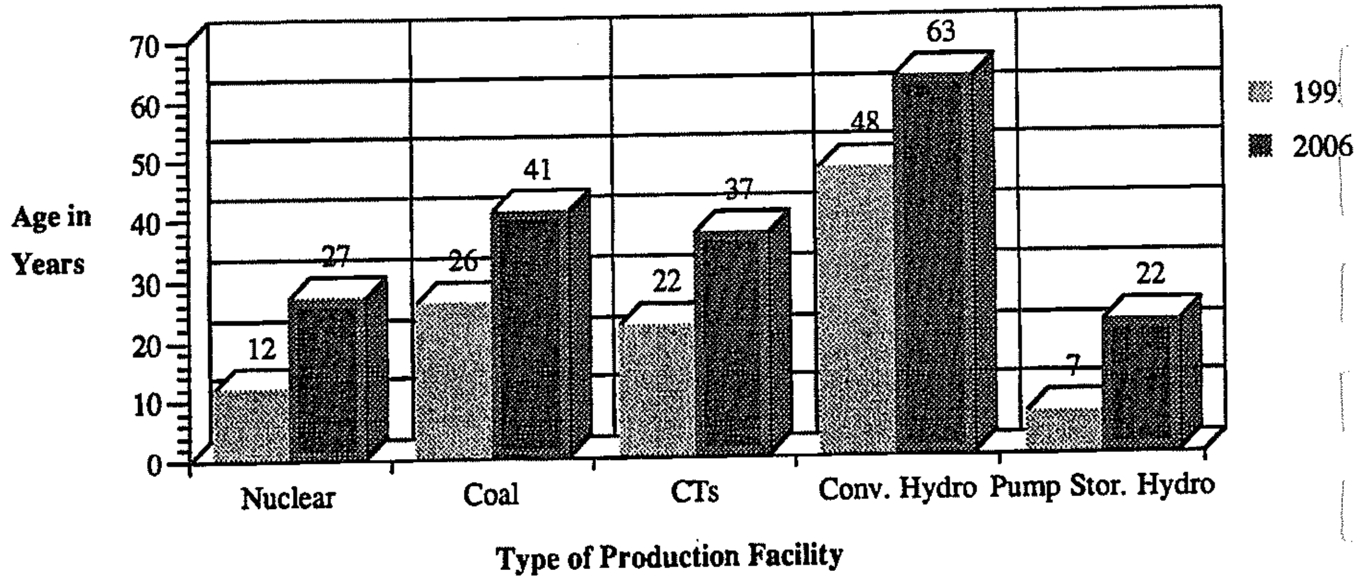
Exhibit 4-3: DUKE POWER 1992 GENERATING CAPACITY IN MW



Appendix IV-1 through Appendix IV-3 show a detailed list of Duke's generating resources expected to be available for the 1992 Summer Peak. The weighted-average age of Duke's production facilities, by type of facility for 1992 and 2006 is shown in Exhibit 4-4.

[1] Of the 7,054 MW of Nuclear Capacity, 1,975.75 MW is owned by certain municipal and cooperative organizations in both North and South Carolina who purchased portions of the Catawba Nuclear Station. These organizations are located in Duke's service area and are partial-requirements customers of Duke. Therefore, their ownership of Catawba is treated as Duke's generating capacity for planning purposes.

Exhibit 4-4: WEIGHTED AVERAGE AGE OF DUKE'S GENERATION FACILITIES



Note 1: Does not include future resources.

Note 2: Based on the sum of MW capacity for each station times its age and then divided by the total MW capacity.

This IRP was developed assuming that Duke's generation capacity will continue to be available beyond 2006, and that operating capabilities will be the same as at present. There are no plans reflected in this IRP for the replacement of existing generation through 2006. However, subsequent studies may indicate such a need.

Resource Replacement

There is a point in the life of a generating unit where it is more cost-effective to replace the unit than to maintain it. Duke is in the process of examining existing generation capability to determine which units or stations, if any, can be economically upgraded and which units or stations, if any, should be replaced. Consideration is being given to the ability of the units to operate economically and reliably. Additionally, Duke is evaluating the environmental compliance of continued operation of each unit and station. Additional information should be available for inclusion in the Short Term Action Plan which will be filed in April 1993.

Clean Air Act Compliance

The Clean Air Act Amendments of 1990 are mainly directed at existing emission sources. Their primary effect will be on Duke's existing eight fossil stations. A summary of the three key portions of the Act relevant to Duke is shown below.

- Title I provides a means to bring areas that are exceeding the National Air Quality Standards (NAAQS) into compliance and maintain compliance. If an area is consistently exceeding the NAAQS for a particular emission then that area is deemed "Non Attainment". The Carolinas have problems meeting the NAAQS for only two emissions, Ozone and Carbon Monoxide. In the Duke Service area nine counties have been designated Non Attainment for Ozone:

  - Mecklenburg
  - Gaston
  - Davidson
  - A portion of Davie
  - Cherokee
  - Forsyth
  - Durham
  - Guilford
  - Wake (A portion is in Duke's service area)

  The states are to submit a plan to the EPA by November 1992 to bring these areas back into attainment. Included in the plan will be Enhanced Inspection and Maintenance for automobiles, and control technology recommendations for major stationary sources of Volatile Organic Compounds (VOCs) and Nitrogen Oxides (NOx). Plant Allen and Riverbend Steam Station, located in Gaston County, are the only Duke fossil plants located in Non Attainment areas. They may require some type of NOx control by 1996 depending on the state attainment plan.

- Title III increases the number of regulated toxic emissions from seven to 189. However, toxic emissions from electric utility fossil generating stations are being studied by the EPA for three years to determine if they need to be regulated. Mercury emissions are being addressed separately in a four year study. Duke is following the development and results of these studies to see how they may potentially impact the system.

- Title IV addresses the amount of Sulfur Dioxide (SO_2) and NOx that can be released from fossil generation units. The goal is a nationwide reduction of 10 million tons of SO_2 and two to four million tons of NOx. To accomplish this goal the following operation restrictions are being implemented:

  SO_2 Control

  Phase I: Starting in 1995 all Electric Steam Generating Units are required to average below 2.5 lbs. of SO_2/MMBTU. All of Duke's units already meet the Phase I requirements and will be subject to Phase II requirements.

  Phase II: Starting in 2000 Duke will have to meet an annual emissions cap of 192,000 tons based on an emissions rate of 1.2 lbs. of SO_2/MMBTU.

  Duke is taking advantage of the interim time period to develop a strategy to meet Phase II requirements. Several compliance options that are being considered are: retire and rebuild, lower sulfur coal, natural gas conversion and SO_2 control technologies; and purchasing SO_2 allowances. Duke has the flexibility of time and multiple compliance options with which to develop and implement a sound, cost-effective compliance strategy by the year 2000. A further update on Duke's progress in developing this strategy will be provided in the future Short Term Action Plans.

NOx Control

Emission limits for NOx controls are being determined by boiler type. The limit for all of Duke's boilers except Belews Creek is .45 lbs. of NOx/MMBTU. This limit may be lowered in 1997 based upon Low NOx burner technology development and national NOx reduction goals. The limit for Belews Creek's type boiler is to be determined in January of 1997. All of Duke's units are subject to Phase II and are required to meet the NOx emission limits starting in 2000. An initial strategy for compliance is under development and will be adjusted as the regulated emission limits are finalized.

Summary

Duke's historical use of washed low sulfur coal (1.5 lbs. of SO_2/MMBTU), aggressive demand side programs and reliance on clean nuclear generation has kept system-wide SO_2, NOx, VOC, and toxin emissions to a very low level when compared to a national average. Regulations are still being developed and finalized and Duke is following developments closely to assure a cost effective and environmentally sound Clean Air Act Compliance strategy.

Aggressive Demand-Side Management that Duke is pursuing is intended to offset demand and reduce system generation requirements. DSM efficiency programs may entitle Duke to claim part of the 300,000 ton SO_2 set-aside for utility conservation programs and renewable resources. This allowance, established by the Clean Air Acts, will be administered by the Environmental Protection Agency (EPA). Allowances will be awarded to utilities on a first-come first-served basis and Duke hopes to qualify for and claim allowances for energy conservation programs.

Steam Generators

Duke's current situation with respect to Stress Corrosion Cracking (SCC) at its McGuire and Catawba steam generators is described in Section 2.3.5. Duke has formed a project team to begin preparations to purchase and install new steam generators. While the final decision to replace and the order of replacement has not yet been made, it is necessary to start this process well in advance due to long procurement lead times. Based on present manufacturing capabilities, the earliest replacement on the first unit could occur in 1996.

This planning cycle incorporates each unit's availability loss during the steam generator replacement and accordingly accounts for replacement of that generation. For planning purposes, a six-month outage for each unit was used.

4.3.2 Purchased Resources

Duke Power has available 486 MW of capacity in purchased power for the year 1992. This capacity is made up of:

- 238 MW from Southeastern Power Administration (SEPA)

- 200 MW from Nantahala Power and Light purchased from Tennessee Valley Authority (TVA) [Scheduled to end in December 1994]
- 48 MW of firm capacity from Non-Utility Generators (NUGS)

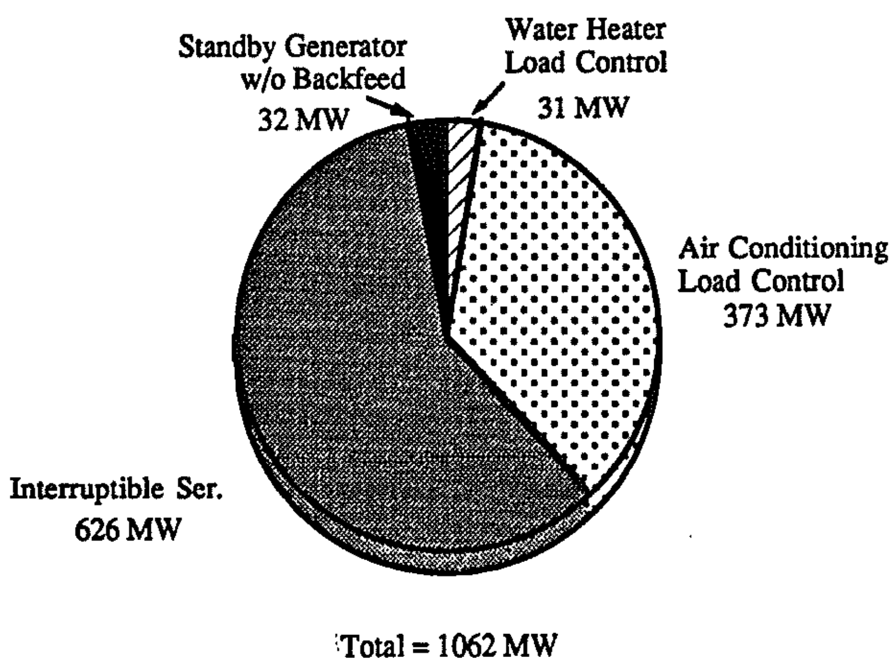
Note: In January 1992, Duke revised the amount of firm purchased power capacity available from Non-Utility Generators under contract to sell power to Duke from 48 MW to 55 MW, incorporating new contracts and reflecting historical experience with existing contracts. The 7 MW increase in purchased power capacity will not materially affect the IRP.

Negotiations and investigations continue on additional purchased power, with none committed at the time of the report.

4.3.3 Interruptible Programs

Interruptible Programs temporarily suspend full or partial capacity service to a customer or end-use. Capacity is purchased from customers in the form of load removal (suspended service) for a period of time. Exhibit 4-5 shows the amount of Interruptible Programs available to Duke as of December 31, 1991. The MW values shown are those available during the summer period and consist of the diversified customer's load at time of Duke's system peak plus transmission and distribution line losses.

Exhibit 4-5: INTERRUPTIBLE PROGRAMS REPORTED MWs AVAILABLE DECEMBER 31, 1991



4.4 Scheduled Resources

Lincoln Combustion Turbine Station (LCTS)

On December 3, 1991, Duke filed an update to the 1991 Short Term Action Plan regarding the impact of IRP analyses on the Lincoln Combustion Turbine Station (LCTS). The current analysis continues to indicate requirements for additional peaking resources. The near-term resource mix is combustion turbines and DSM resources. Supply-side peaking capacity, in the form of CTs, is important to the effective operation of the balance of the Duke system.

The December 1991 update to the 1991 Short Term Action Plan changed the construction schedule for combustion turbine units at the LCTS to four units in 1995, four units in 1996, and the remaining eight units in 1997. This update was a result of this IRP process. This change is due to economic conditions and higher than anticipated market penetration of Demand-Side programs. The corresponding project cost is $537,470,000. This cost exceeds the upper range of costs presented in Duke Power's NCUC Rule R8-61(b) information, subsection 9.1.1, by approximately 3.8%. While the increase in project cost is attributable only to the inflationary effect of the schedule change, the increase is less than the full impact of the assumed inflation rate of 5% per year. This limited increase results from Duke's success in securing equipment contracts at a lower cost than earlier estimates.

Duke obtained the Certificate of Convenience and Necessity for the project in March 1991. Engineering for the Lincoln project is scheduled for completion at the end of the first quarter of 1992. Construction has not begun and no equipment has been released for fabrication. Duke is proceeding to obtain required state and local permits. Listed below are the state and federal permits required for the LCTS and their status:

- 404 Wetlands Permit (Federal) - Application to be filed
- 401 Water Quality Certification (State) - Application has been submitted
- 404 Dredge and Fill Permit (Federal) - Permit received 10/21/91
- National Pollutant Discharge Elimination System Permit (State) - Application has been submitted
- Air Quality Permit (State) - Permit received 12/20/91 and is currently being contested
- Erosion and Sediment Control Permit (State) - Permit received 12/3/91
- Solid Waste (Demolition Landfill) Permit (State) - Application to be filed
- Driveway Connection Permit (State) - Permit received 8/12/91
- Drinking Water Permit (State) - Application to be filed

Plant Modernization Schedule

Duke Power is currently pursuing a maintenance and modernization program for several older coal fired units. This Plant Modernization Program (PMP) is expected to increase both the reliability and availability of these units. The repairs and equipment replacements were unit-specific, but consisted of new control systems, turbine rotor and generator field replacements, boiler tube replacements, feedwater heater replacements, precipitator repairs, fuel handling and pulverizing system upgrades, and valve and piping repairs. A significant amount of work has been completed and materials have been procured for the remaining PMP units. In addition, a substantial amount of the dollars budgeted to them have been spent. Exhibit 4-6 provides the PMP schedule used in the integrated planning process.

Exhibit 4-6: PLANT MODERNIZATION PROGRAM SCHEDULE

Station	Unit	Capacity (MW)	Completion Date
Buck	3	70	Summer 1993
Buck	4	38	Summer 1994
Cliffside	1	38	Summer 1994
Cliffside	2	38	Winter 1993/94
Cliffside	3	61	Winter 1991/92[1]
Riverbend	6	133	Winter 1991/92[1]
Riverbend	7	133	Winter 1992/93

[1] The work on these units has now been completed.

With no base load generation additions planned until 2006, Duke's existing system will be required to run at increasing capacity factors to meet growing capacity and energy demands. Restoring the availability and reliability of these older units is important to Duke's ability to meet these needs.

There are no current plans to extend PMP to additional stations or units. However, the overall system, including PMP units, will be subject to generation replacement studies.

4.5 System Betterment

From its beginning, Duke has been faced with the need to add new or upgrade existing transmission and distribution facilities. The primary driver for these system changes has been the expanding customer needs of the Duke service area. Duke has pursued economical and efficient designs to ensure service reliability and needed operational flexibility. Along with capital, maintenance and other operating costs, the cost of losses associated with equipment and conductors have been considered when making system changes.

Duke has developed a comprehensive 'Guide for Evaluation of Transmission and Distribution Losses'. This guide provides a uniform, aligned and integrated method to evaluate the cost of both capacity and energy losses associated with a system facility over its operating life. Duke has not maintained records on the benefits which have accrued due to reduced capacity and energy losses occasioned by its system engineering and operating decisions. However, Duke is considering the establishment of procedures for collecting data in order to document the benefits derived from system betterment projects.

Examples of betterment projects involving evaluation of savings due to reduced losses include:

Purchasing Transformers

When Duke requests bids for distribution transformers, the vendors are supplied with the value to Duke of no-load losses and load losses (commonly called A & B factors in the industry). The vendor then quotes a price based on the total owning cost of the transformer assuming a thirty year life. To date, even though amorphous core transformers inherently have low loss characteristics, no vendor has quoted amorphous core transformers that have the lowest owning cost. The purchase of other system transformers is handled similarly.

Reconductoring Lines

When loading requires reconductoring a line, the evaluation for selecting the most effective conductor size is based on a number of technical factors including line losses.

Generating Plant Auxiliary Equipment

There are equipment changes which, if made, can result in small improvements (less than 1 MW) in plant efficiency. Several variable speed drives which have been evaluated result in loss savings and have potential to improve overall plant efficiency.

Voltage Conversions

Several 4 kV stations are being evaluated for conversion to a higher voltage. While some of these are under consideration for reasons of safety and maintenance, the value of loss savings may determine the decision in others.

4.5.1 Transmission Additions

The major transmission additions and increases over the next five years are listed in Exhibit 4-7. Additional projects are planned after the five year window, however their schedules are not firm. These projects have been tested with least cost criteria based upon lowest present worth revenue requirements. Several of the projects in the next five years are 500-230 kV transformer capacity increases which will serve to maintain or increase the reliability and flexibility of the bulk transmission network as well as maintain or increase Duke interconnection capabilities.

Exhibit 4-7: SCHEDULED TRANSMISSION ADDITIONS AND INCREASES

Project	Location	Capacity	Scheduled Completion Date	Notes
Oconee 500-230 kV Transformer Capacity Increase	Seneca, SC	1500 MVA	Fall 1992	Increase Capacity By 500 MVA
Stamey Tie 230-100 kV Transformer Capacity Increase	Statesville, NC	1200 MVA	Fall 1992	Increase Capacity By 400 MVA
Rural Hall 230-100 kV Transformer Capacity Increase	Rural Hall, NC	1100 MVA	Fall 1992	Increase Capacity By 100 MVA
Newport 500-230 kV Transformer Capacity Increase	Newport, SC	1000 MVA	Spring 1993	Increase Capacity By 250 MVA
East Durham Tie Station 230-100kV	Durham, NC	700 MVA	Spring 1993	Add 230-100 kV Tie Station
Tiger Tie 230-100-44 kV Transformer Capacity Increase	Duncan, SC	800 MVA	Fall 1993	Increase Capacity By 300 MVA
Antioch Tie Station 500-230 kV	N. Wilkesboro, NC	1500 MVA	Fall 1994	Add 500-230 kV Tie Station
CP&L 230 kV Interconnection At East Durham Tie	Durham, NC	700 MVA	Fall 1994	CP&L Will Fold In Their Method To Roxboro Line
Lincoln County(1) 230 kV Switchyard	Lincolnton, NC	----	Fall 1994	Switchyard For CT Plant

(1)Pending Lincoln Combustion Turbine Station.

4.6 Bulk Power Sales

This integrated planning process incorporates a six year, 400 MW bulk power sales agreement between Duke and Carolina Power and Light (CP&L). The delivery to CP&L was scheduled to begin in 1992. This proposed agreement was accepted for filing by the Federal Energy Regulatory Commission (FERC) in March of 1989. Following the completion of the 1992 Integrated Resource Plan, the sale to CP&L was delayed and is now scheduled to begin in July 1993 and be completed in June 1999.

4.7 Summary

As shown throughout the preceding discussion of its operating environment, Duke continually makes aggressive evaluation of all key factors in its operating environment, both on the supply and the demand-side. Additionally, Duke has also made a determined effort -- not only to meet the currently mandated environmental standards -- but to assess the impact of future standards before they are imposed.

Duke's assessment of all the key factors of its operating environment is carefully applied to both the supply and demand side of its Integrated Resource Plan and is reflected in every step of the modeling process.

The ability of Duke to anticipate and aggressively react to both the opportunities and challenges in its operating environment has been a key factor in its ability to meet the demands of its customers with reliable power at the lowest reasonable cost.

5.0 FORECAST

5.1 Introduction

Duke Power Company produces a 15-year forecast typically during the spring of each year to help determine the future capacity needs, energy needs and the resulting financial requirements. The forecast projects the peak demand for both the summer and winter seasons and annual energy for the service area. The forecast of both the peak demands and energy are provided by major customer classes.

The primary forecasting technique used at Duke for the forecast of peak demand and energy is econometric forecasting analysis. Duke has received historical and forecasted national information from Wharton Econometric Forecasting Associates (WEFA) to produce a service area economic forecast. This service area forecast then serves as an input to the most likely peak demand and energy forecasts.

This forecast serves as a primary input into Resource Integration. Four other forecast scenarios are produced, two "high" and two "low", which address the risk and uncertainty of forecasting. These scenarios will be discussed in Section 5.3.3.

5.2 Process Overview

The Duke Power Service Area Economic Model

The starting point for the Duke forecast is the service area economic model. Beginning with the 1991 forecast, Duke started projecting a new economic concept. Duke has projected gross regional product (GRP) as the measure of economic activity. GRP is the regional counterpart to the gross national product and measures the production of all goods and services within the Duke service area. The projections of gross regional product are made by the standard industrial classification (SIC) level. The major reason for changing to the projection of gross regional product was to have a true measure of total production for the service area and to have better measures of production at the SIC level particularly in the manufacturing sector which makes up an unusually large percentage of Duke's customer base.

The primary products of this model -- employment, personal income, and gross regional product -- are used in the development of the sales and peak models. The flow chart (Exhibit 5-1) demonstrates how the service area economic model progresses.

Service area economic model forecasts are based on historical and forecasted macroeconomic and regional economic data from Wharton Econometric Forecasting Associates (WEFA) and service area historical data from the Bureau of Labor Statistics (BLS) and the Bureau of Economic Analysis (BEA). Through econometric analysis, historical relationships are developed mainly between the service area historical data and macroeconomic/regional data. Forecasted macroeconomic and regional data from WEFA are used to project the service area economic data. (However, feedback exists within the service area economic model between the service area manufacturing employee-hours and service area gross regional product. Thus, the projections of employee-hours depends on the projections of gross regional product and the projections of gross regional product via manufacturing wages depend on manufacturing employee-hours. This feedback will be discussed further in the supplement to this 1992 IRP entitled "Forecasting Equations.")

The service area economic model consists of 133 equations. The economic model serves as the primary input to the demand and energy forecast. Much detail is needed to accurately reflect and forecast the service area economy and have economic projections for future end-use modelling needs. From this model are derived three categories of indicators of the economic health of the service area: (real or inflation-adjusted) gross regional product; real total and disposable personal income; and employment. The service area gross regional product components serve as critical inputs for part of the forecasts of the peak, general service energy, and industrial energy. (The service area income forecast is an input for part of the peak, residential energy, and general service energy forecasts. Parts of the employment forecast serve as an input to certain segments of the general service energy forecast.) (See Exhibits 5-2 and 5-3).

Exhibit 5-1: DUKE SERVICE AREA ECONOMY PROCESS

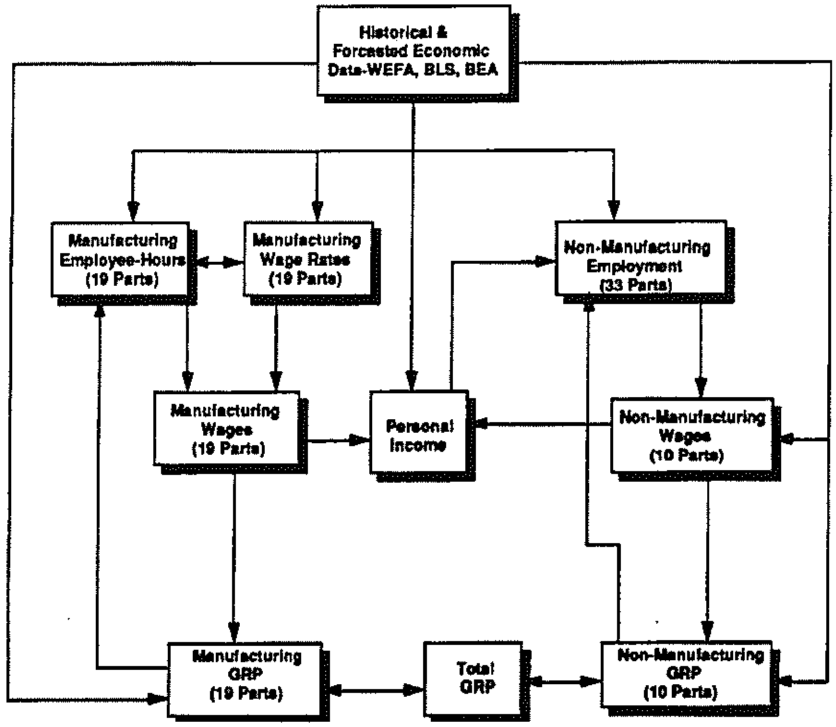


Exhibit 5-2: PEAK DEMAND MODELS PROCESS

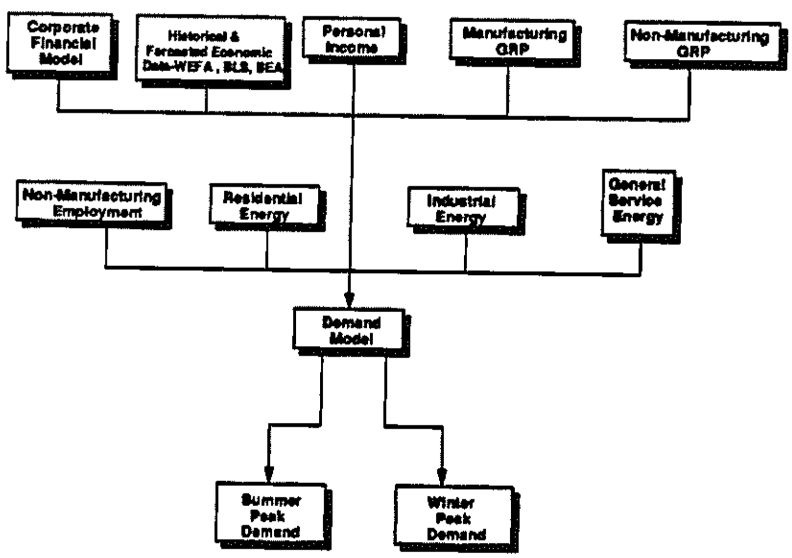
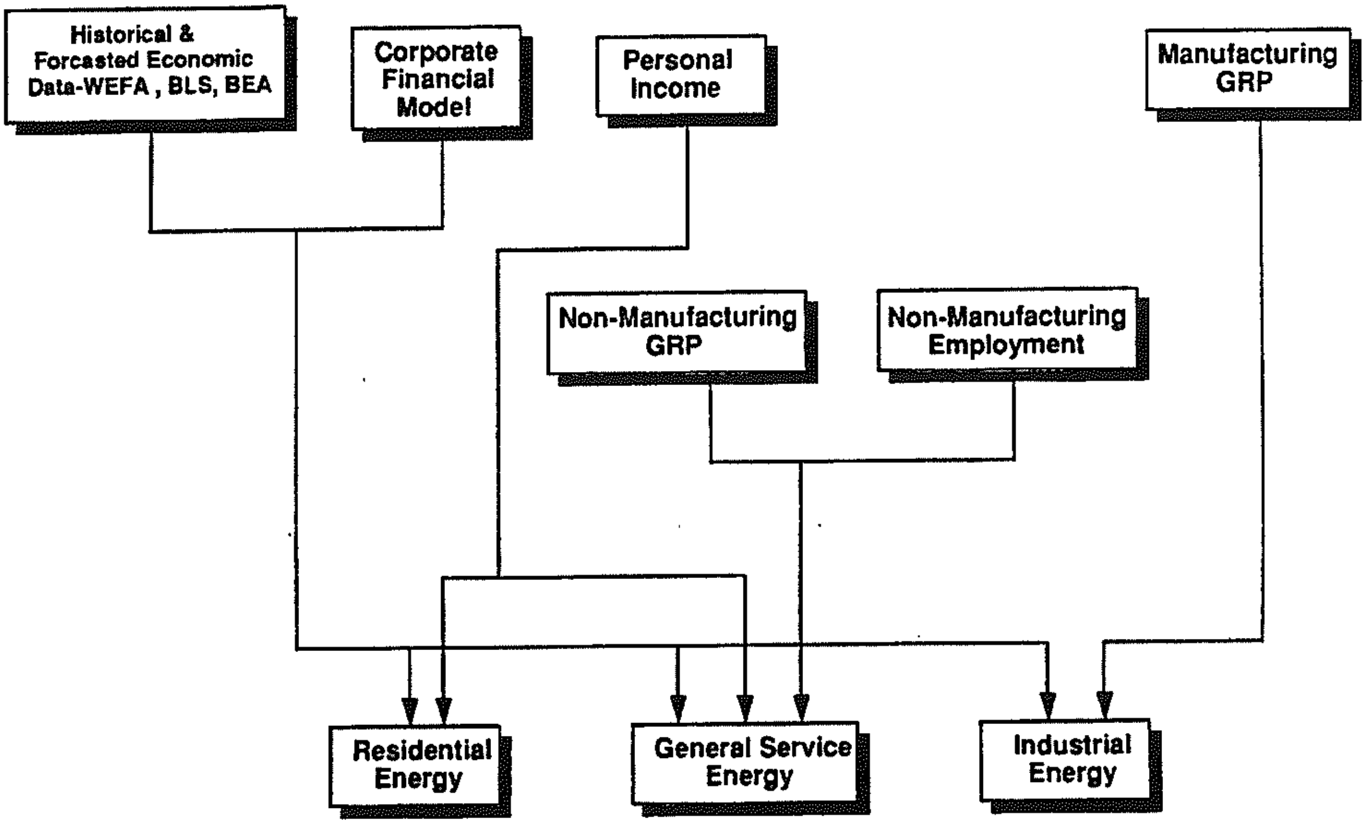


Exhibit 5-3: ENERGY MODELS PROCESS



The peak demand and energy models also incorporate projections of the real price of electricity which is produced by the corporate financial model.

Peak Demand Models

Results from the service area economic model are utilized to derive both the summer and winter peak demands. (See Exhibit 5-2). Other factors used in developing the summer and winter peak demand models and resulting forecasts include air conditioning, electric heating, and electric water heating appliance saturations, number of customers from the energy models, and temperature. The details of this model will be discussed in section 5.3.

Residential Energy Model

Certain results of the service area economic model, primarily real disposable personal income, are incorporated into the residential energy model. (See Exhibit 5-3). Other factors used in developing the residential energy models include service area population, real mortgage interest rates, fuel prices, appliance saturations, and temperature. This model produces projections of energy and the number of residential customers by various types. The details of this model is discussed in the supplement to this 1992 IRP entitled "Forecasting Equations."

General Service Energy Model

This class of customers include everything that is neither a residence nor a manufacturing industrial operation. Therefore, this customer class includes such things as offices, restaurants, churches, and even billboards. Some of the outputs of the service area economic model, primarily real total and disposable income and components of real gross regional product, operate as inputs to the general service energy model. Other inputs include service area population, certain sectors of non-manufacturing employment, fuel prices, the prime interest rate, and temperature. Output from this model include projections of energy and the number of general service customers by various types. The details of this model is discussed in the supplement to this 1992 IRP entitled "Forecasting Equations."

Industrial Energy Model

Industrial energy has as its primary input the components of manufacturing gross regional product from the service area economic model. Other inputs include fuel prices and temperature. The output from this model is energy by two digit SIC for the manufacturing industries. The details of this model are discussed in the supplement to this 1992 IRP entitled "Forecasting Equations."

External Evaluation

As in any forecasting process a model by itself is inadequate without the use of judgment, external views and external information. That is, an equation by itself is a useful tool for forecasting, but the forecaster must consider all available information, not just the information contained within the equation. In an endeavor to make the most reliable forecast possible, Duke considers various sources of external information to make sound judgments concerning the validity of the forecast and assumptions.

The modelling approach of the peak demand and energy forecasts used have been reviewed over the years by Chase Econometrics (later WEFA) and by Kenneth H. Robertson of ICF, Inc. The consultants confirmed this modelling approach for peak demand and energy. Chase Econometrics/WEFA and Mr. Robertson have also confirmed the service area economic model as being reasonable. Other sources of outside information for the service area economic, peak demand and energy models include the National Association of Business Economists (NABE), the Edison Electric Institute (EEI) Economics Committee, various professional magazines and newspapers from the service area.

5.3 Forecast Results

5.3.1 Aggregate Forecast Results

Duke Power Company completed the current long-term forecast of peak demands and energy for the period 1991 through 2005 during May, 1991. This forecast can be seen in Exhibit 5-4.

Exhibit 5-4: PEAK DEMAND AND ENERGY FORECAST

	Summer (MW)	Winter[1] (MW)	Territorial Energy[2] (GWH)
1991	14,522	14,285	76,609
1992	14,852	14,694	78,761
1993	15,169	14,952	80,226
1994	15,549	15,317	82,046
1995	15,990	15,731	84,385
1996	16,383	16,133	86,661
1997	16,798	16,520	89,177
1998	17,248	16,943	91,406
1999	17,724	17,374	93,982
2000	18,069	17,794	96,410
2001	18,519	18,173	98,818
2002	18,949	18,573	101,062
2003	19,429	18,967	103,464
2004	19,772	19,334	105,774
2005	20,185	19,731	107,903
2006[3]	20,590		110,156

[1] The summer peak demand is for the calendar year indicated. The winter peak demand is for the winter following the summer peak demand.
[2] Territorial energy is the total energy consumed within the service area.
[3] 2006 is not part of the official Forecast, but is used in the Integration Process.

The summer peak demand grows at a 2.4 percent annual growth rate. This rate compares with a 3.1 percent growth during the 1978-1990 time period for the temperature corrected summer peak demand. The winter peak demand grows at a 2.7 percent growth rate during the forecast horizon. This rate compares with a 3.1 percent growth during the 1978-1990 time period for the temperature corrected winter peak demand. Even though the winter peak growth rate exceeds that of the summer, Duke expects to remain summer peaking. Energy is projected to grow at a 2.4 percent rate for the forecast period. This rate of growth compares with a 2.8 percent rate of growth during the 1978-1990 time period. The slower rates of growth for the peak demands and energy over the forecast period are due to the overall slower economic growth during this forecast period.

5.3.2 Specific Forecast Results

Exhibit 5-5 shows the historical and forecasted summer peak demand percentage growth by customer class.

Exhibit 5-5: PEAK DEMAND ANNUAL GROWTH RATES

YEAR RANGE	RESIDENTIAL	GENERAL SERVICE	INDUSTRIAL
1980-1990	2.8%	4.7%	2.0%
1990-2005	2.5%	3.0%	1.6%

Residential peak demand is expected to increase 2.5 percent per year during the forecast period. Since 1980, the historical growth rate has averaged 2.8 percent per year. The decline in the growth rate is primarily due to increased insulation usage and increased growth in heat pump utilization.

The general service sector is the fastest growing customer class in the Duke service area. The customer class consists of all customers who are not residential nor industrial, and includes everything from high-rise office buildings to billboards. The peak demand in this class grew historically at 4.7 percent per year between 1980 and 1990. The peak demand is expected to grow in this class at 3.0 percent per year from 1990 through 2005. This lower growth rate is due to the slower projected economic and population growth in the service area over the forecast period.

The peak demand industrial class of customers grew at 2.0 percent per year from 1980 through 1990. It is expected that growth will be 1.6 percent per year from 1990 through 2005. Growth is slower in the forecast period because of a slower growth in the industries moving into the service area and due to a overall slower projected economic growth in the service area. It is expected during the forecast period that the peak demand for the textile customers will constitute a smaller share of the total industrial peak demand, while the other industrial category will have an increasing share.

Exhibit 5-6 shows the historical and forecasted energy percentage growth by customer class.

Exhibit 5-6: ENERGY AVERAGE ANNUAL GROWTH RATES

YEAR RANGE	RESIDENTIAL	GENERAL SERVICE	TEXTILES	OTHER INDUSTRIAL	TOTAL ENERGY
1980 - 1990	2.3%	4.8%	0.9%	4.1%	3.0%
1990 - 2005	2.0%	3.2%	1.2%	2.7%	2.4%

Residential energy requirements are projected to increase 2.0 percent per year during the forecast period. Since 1980, the historical growth rate has averaged 2.3 percent. The major trend in the residential class is that electric heating customer's kilowatt-hour per customer (KPC) consumption has declined 333 KPC each year on average since 1980. This decline is due to increased insulation usage and growth in heat pump utilization in lieu of resistance heating. This decline has occurred even though there have been increases in the size of the average dwelling unit and an increase in the saturation of air conditioners.

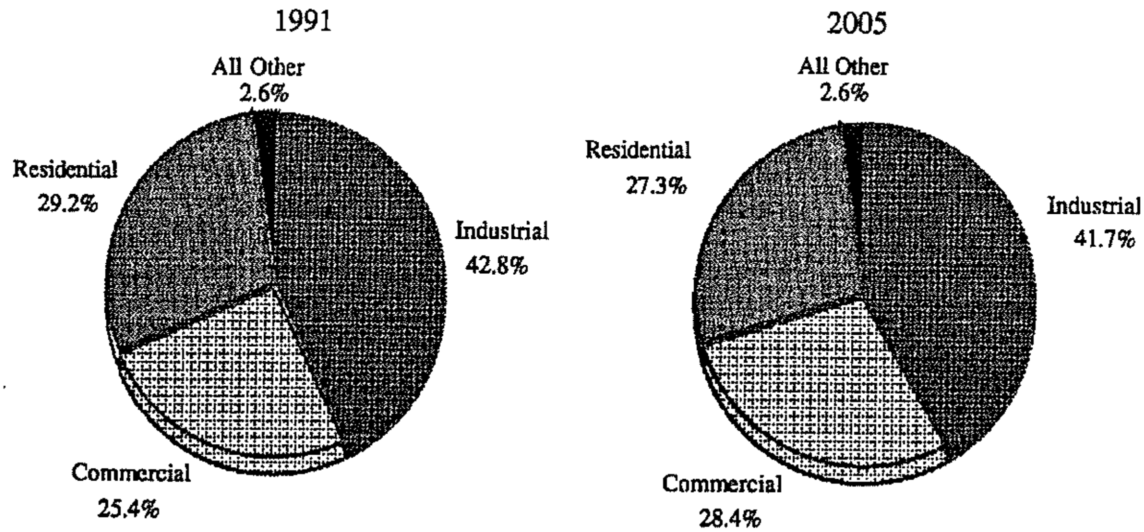
The general service sector is the fastest growing customer class in the Duke service area. Historical growth from 1980 through 1990 increased at an average annual rate of 4.8 percent. The growth over the forecast period is projected to be 3.2 percent. This lower growth rate is due to the slower projected economic growth and population growth in the service area over the forecast period.

The growth in this sector reflects the continuing change in the service area economy to an increasing commercial employment base. The commercial share of the service area employment has increased from 66 percent in 1980 to 72 percent in 1990. A more productive, capital intensive industrial sector along with the emergence of Charlotte as a major banking center has contributed to this shift.

The Duke service area has an unusually large concentration of industrial customers. Industrial energy currently represents 43 percent of total energy. Nationally this share is approximately 30 percent. Industrial energy is expected to grow at approximately 2.1 percent per year from 1990 through 2005. This rate compares with a 3.0 percent growth from 1980 through 1990. The lower growth in the forecast period is due to an overall slower projected economic growth in the forecast horizon based mainly on a decreased in-migration of industry into the service area.

Textile sales, which presently constitutes 43 percent of all industrial sales, will increase at a relatively low 1.2 percent annual rate which is consistent with the historical rate of 0.9 percent. Energy sales to industrial customers excluding textiles are larger contributors to growth than the textile industry. The projection for this class of customers is for 2.7 percent from 1990 through 2005 which compares to an historical growth rate of 4.1 percent from 1980 through 1990. Major contributors to this growth in the other industrial category include food products, paper, and rubber and plastics. Exhibit 5-7 shows the percentage share of KWH sales by customer class for 1991 and 2005.

Exhibit 5-7: PERCENT KWH SALES BY CUSTOMER CLASS - 1991 AND 2005



5.3.3 Uncertainty and Risk

To assist in the sensitivity analysis -- discussed in Risk Assessment (10.0) -- four different projections are generated for system peak demand. Two of the forecasts are higher than the base forecast, and two scenarios are lower. These forecasts were based on an 80 percent confidence factor that the future would occur within the range defined by the high and low forecast.

These different scenarios are derived by assuming the percent growths of the peak demand and energy follow a normal distribution. The percent growth deviations from the base forecast are based on deviations from the different scenarios of WEFA's national forecast.

5.4 End-Use Forecasting

5.4.1 Definitions and Comparisons

Currently, the forecasting tool is econometric forecasting analysis which is based on the statistical estimation of economic relationships. Alternatively, end-use forecasting analysis is a forecasting technique based on engineering relationships. The end-use technique attempts to quantify the relationship of electricity usage by appliance, e.g., motor drives in the industrial sector to engineering concepts, such as efficiency standards. The forecast of usage by appliance then depends on the projected values of these engineering concepts. Then, the forecast of total usage by class is the summation of electricity usage by all appliances within that particular customer class.

As discussed in Appendix II-2 Duke has adopted end-use methodology into the forecasting process to account for demand-side management potential and achievements, to incorporate factors affecting electricity usage, and to incorporate end-use trends.

Duke believes that the econometric forecasting technique will give a more reliable forecast in the short-term by customer classes. But, the end-use forecasting technique adds value by producing forecasts by end-use appliances and by revealing long-term trends of changing efficiency standards and DSM activity. The largest challenge to utilizing the end-use techniques in the short-term is the unavailability of necessary end-use data for the service area. Duke is collecting as much end-use data as possible to improve its end-use forecasting ability.

The econometric forecast from this process assumes that the rate of change in efficency standards and in DSM activities remain the same as has occurred historically. The end-use forecasting technique can reflect projected changes in efficiency standards and DSM activities which cannot be reflected by econometric forecasting techniques. So, the econometric forecast is a "baseline" forecast. The end-use forecast will be used to make adjustments in the econometric forecast.

5.4.2 Preliminary Actions

Duke is evolving to a "hybrid" econometric/end-use forecasting process. Significant accomplishments have been made towards the evolution to this hybrid process. The peak demand model was changed from a single equation for each season to equations for each major customer class, i.e., residential, general service, textiles, industrial excluding textiles. This change was made to better understand the impacts of each customer class on total system peak demand and to assist in the alignment of the econometric and end-use efforts. To better understand the commercial class and to assist in the alignment of the two forecasting processes, a new approach was used in the 1991 forecast in the general service energy model. The approach is based on using SIC codes to group energy sales into 12 different groups. The model used in previous forecasts had two groups based on broad customer classifications. These 12 groups are offices, transportation, retail trade, education, wholesale trade, restaurants, food stores, hotels, churches, amusement, medical, and miscellaneous.

5.4.3 Initial Accomplishments of End-Use Techniques

The initial emphasis in end-use techniques concerned the forecast of load shapes by end-use. The results of these forecasts could be applied directly into the models used to screen and evaluate demand side options. Conversely, end-use energy forecasts could show only the impacts on total annual energy of DSM programs and options, and these forecasts alone could imply little about the reduction in capacity requirements.

Residential End-Use

The primary focus of work to date has been on forecasting residential end-use load shapes. A conditional demand analysis model was developed which would generate end-use load-shapes based on household and structure characteristics. Load shapes were generated for the following appliances: heat pumps, central air conditioning excluding heat pumps, electric resistance heating, window air conditioning, electric water heaters, freezers, electric clothes dryers, and other electricity usage.

Load shape forecasts of these appliances were produced for the forecast period. The summation of these appliance forecasts produced a total residential energy and demand forecast. The energy forecasts appeared reasonable when compared with the residential econometric energy forecast. However, the load shape forecasts appeared unreasonable due to a lack of service area specific data. Work is proceeding on the load shape forecast and planned enhancements are discussed in the Short-Term Action Plan (12.0).

Commercial End-Use

A study of DSM in the commercial class began by developing commercial building load shape profiles. Hourly load data was collected on a sample of commercial customers through load research information. A survey of each commercial sample customer's location gave information which allowed Duke to categorize these customers into building types. Hourly profiles were developed for six of these building types (offices, retail trade, education, food stores, medical, and restaurants). The intent is to use these load profiles in the evaluation of DSM programs and options for the commercial customers.

Industrial End-Use

It was decided to delay any development on the industrial end-use process pending the availability of the EPRI industrial end-use modelling software INFORM. A test version of this software was received in February, 1992.

6.0 DEMAND-SIDE RESOURCES

6.1 Introduction

The purpose of this section is to describe Duke's comprehensive approach to the identification and development of DSM options from available "technologies" (end-use equipment, concepts of demand/energy savings, etc) and the optimization of these options. Not only are new options analyzed, but existing programs are reviewed for possible revision and to ensure they maintain their cost-effectiveness. New options and revised programs are then included in the planning process. Only at the end of the planning process are viable options considered programs for implementation in the Duke service area.

To meet its customers' growing need for electric energy, Duke selects a mix of demand-side resources, supply-side resources and purchase resources. Demand-side resources consist of existing demand-side management (DSM) programs and DSM options (potential programs) that impact forecasted system capacity and energy consumption. Resources may be energy efficient, load shift, interruptible or environmental.

Energy efficient resources reduce the customer's demand and energy consumption throughout the operating times of the resource. Load shift resources "shift" the operational periods of a resource from "on peak" periods to "off peak". This "shift" reduces capacity needs while energy requirements are generally unaffected. Interruptible resources remove customer's capacity needs from Duke's system when necessary to meet total system capacity requirements. The customer's total energy usage is only minimally affected. Environmental resources address Duke's desire to aid customers in meeting environmental requirements as efficiently as possible.

The majority of Duke's past DSM accomplishments are the result of interruptible programs. Energy efficiency options comprise the majority of new options considered in the current process. Additional new options considered and outlined in this section are environmental and interruptible.

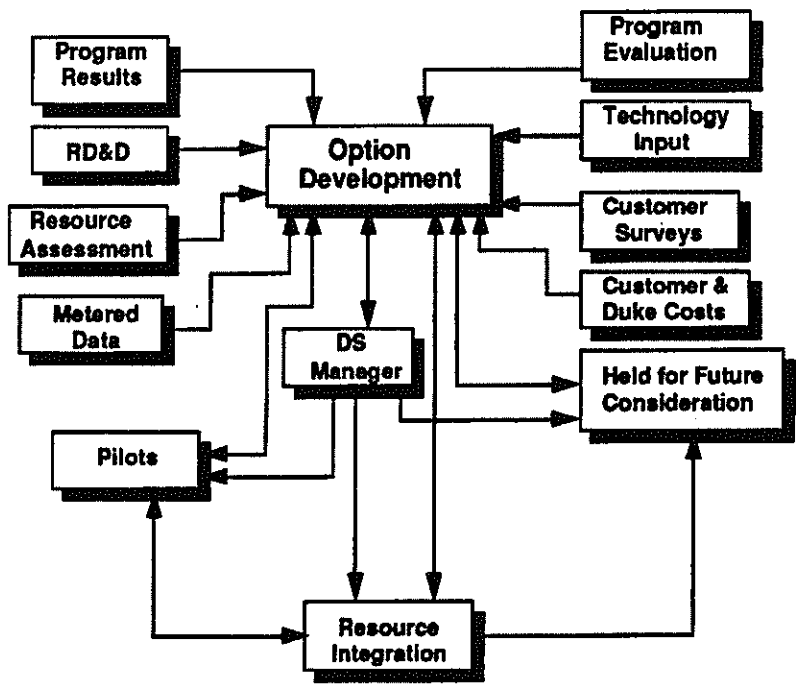
The development of DSM options require support activities to provide input for the process. Pilot projects, for example, are used to resolve any uncertainties associated with the implementation of DSM options. Duke has also embarked on a DSM total resource assessment effort to quantify DSM maximum potentials in the Duke service area. Once potentials are identified, DSM options can be developed to harness those potentials. Although the DSM assessment provided no input during this integrated planning process, it will provide valuable input for future option development. Similarly, a residential and commercial end-use metering project has begun to return data for subsequent use. End-use metering will assist the development of DSM options by providing load shape data. Data from end-use metering available in late 1991 will play an increasing role in future IRPs. Finally, technology Research, Development, and Demonstration (RD&D) provides a mechanism by which emerging issues and technologies can be analyzed for feasibility. Also, RD&D will verify or develop the technical input data needed for these issues and technologies.

As DSM programs continue to play a larger role in meeting customer needs and future capacity requirements, the identification, selection and development of new options as well as improving existing programs will be critical to the integrated planning process.

6.2 Process Overview

Demand-Side option development normally begins with a "technology" (process concept, new/improved end-use equipment, etc.) review, or an existing program review. Existing programs are either included in the Updated Plan with no changes or revised and treated as new options. Technologies are selected that can effectively accomplish DSM objectives, such as load shift, interruptible, environmental and energy efficiency. A wide array of resources are used to identify and develop new DSM options from these technologies. Computer software that models customer energy characteristics is coupled with customer survey results, utility experience and other inputs to formulate options that could become successful DSM programs. The demand-side process diagram is shown in Exhibit 6-1.

Exhibit 6-1: DEMAND-SIDE PROCESS DIAGRAM



Developing a specific option or revising an existing program requires the incorporation of analyses of end-use and total load shapes with extensive market research. The end-use and total load shapes are used to estimate demand and energy impacts. The required research for each option estimates market size, costs, customer demographics, free rider levels and potential option barriers and constraints. Free rider levels are used to identify customers who would have implemented the desired response of a DSM program or option even if Duke had not implemented such DSM program or option. Demand and energy impacts for free riders are incorporated in the forecast. Methods for research include customer surveys, focus groups and other customer research tools. Much of the experience gained from previous DSM programs offered to customers, plus other utilities' experiences, are used to develop options. This preliminary screening of selected technologies for possible development into specific DSM options is based on the following criteria:

- Technological feasibility

- Ability to accomplish demand reduction, load shift, energy efficiency or environmental needs
- Customer acceptance and market potential
- Availability of sufficient technical and other data for analysis

Options under review that do not meet any of these criteria may be sent to pilot or held for future consideration.

Existing programs are reviewed regularly. A program evaluation procedure is being developed to serve as the program review in future processes. If review of an existing program shows the need to reanalyze the program due to a change in cost, customer penetration or demand and energy impact estimates, the program is revised and screened using the same guidelines as a new option and becomes another option in the process. Another aid in this review is a DSM program cost tracking procedure that has been implemented by Duke to identify any and all costs associated with an existing DSM program. Although information from this procedure was not available for this planning process, cost tracking has been implemented and will be used in future processes. Existing programs that are not revised are included in the Updated Plan in Resource Integration with no changes in projected accomplishments.

New DSM options that successfully meet the preliminary screening criteria are then considered resource options in Resource Integration. Each option is categorized as energy efficient, load shift, interruptible or environmental. Before submitting options to Resource Integration, Duke uses EPRI's DSManager for an initial review and optimization. DSManager provides an indication of the relative effectiveness of the DSM options or revised programs for optimization. Interruptible options are not screened with DSManager. DSManager does not lend itself to the analysis of interruptible options with negligible energy impacts. More information on the operation of DSManager can be found in Appendix VI-1.

Based on results from DSManager, an option may be passed to the integration process, placed in pilot, returned to the option development step for revisions and screening in DSManager, or a combination of these. Options that are not eventually piloted or passed to the integration process are held for future consideration. Economic results of DSManager are not used as an indicator for holding an option for future consideration. Uncertainties and risks that require further investigation and analysis are reasons an option may not be passed to integration or piloted.

For DSManager screening purposes, an option may consist of different cases that reflect varying costs, incentives and/or customer penetrations. In most instances, only the most effective case is passed to the integration process. However, multiple cases may be passed to integration to determine which case or combination of cases creates the most effective option.

A pilot may take as long as two to three years to address the uncertainties or other concerns being targeted. If the pilot results indicate no change from the method and inputs that were used in the option's original evaluation, the pilot will be reinstated in the next annual planning process as appropriate. The piloted option may also be reviewed aperiodically to verify that system changes (such as forecast, capacity credits or system marginal costs) do not dilute its value. If pilot results show a need for changes, the option is passed back to the beginning of option development for inclusion in a subsequent planning process.

Those options held for future consideration are returned to option development to be reanalyzed in the future when changes in technologies, forecasts, and/or other data become available to make them viable options.

6.3 Demand-Side Options/Programs

6.3.1 Programs and Options for Resource Integration

Listed below are the existing programs and new options reviewed for the integrated planning process. The Results section lists those that were forwarded to resource integration.

The existing programs that were reviewed for the process are listed in Exhibit 6-2. Their estimated accomplishments through 1991 plus their projected accomplishments are included in the Updated Plan and listed in Section 6.4 in Exhibit 6-6. Since these accomplishments were estimated in the first quarter of 1991, the accomplishments through 1991 used in this process will be slightly different from the reported accomplishments shown in the Short-Term Action Plan in Exhibit 12-2.

Exhibit 6-2: EXISTING PROGRAMS

Residential Load Control - Air Conditioning
Residential Load Control - Water Heating
Residential Controlled Off Peak Water Heating
High Efficiency Heat Pump Payment
High Efficiency Central Air Conditioning Payment
Residential Add-On (Dual Fuel) Heat Pump
High Efficiency Freezer Payment
High Efficiency Refrigerator Payment
Residential Insulation - New Residences (2% Discount)
Residential Insulation Loan
Interruptible Service
Standby Generator Without Backfeed

Some existing programs were revised for the 1991 process. For those existing programs not revised, their projected accomplishments used in the Updated Plan were unchanged from the accomplishments used in the previous plan. The Updated Plan included no additional customers for revised existing programs. Estimates of additional customers for these programs were established and then analyzed in the process as new options against the Updated Plan.

The new DSM options that were reviewed and analyzed for inclusion in the integration portion of this cycle are listed in Exhibit 6-3.

Exhibit 6-3: NEW DEMAND-SIDE OPTIONS

Energy Efficient Options

Residential Water Heater Insulating Blanket
Residential High Efficiency Lighting
Residential HVAC Tune-Up
High Efficiency Central Chillers for Air Conditioning
High Efficiency Unitary Equipment for Air Conditioning
Non-Residential High Efficiency Indoor Lighting
Motor Systems

Interruptible Options

Standby Generator with Backfeed
Standby Generator - Capacity Improvement
Standby Generator - Category C

Environmental Options

Metal Finishing - Recover Plating Solutions
Textile - Reduction of Waste-Water Effluent

DSM options that have been analyzed in previous integrated planning processes and are being piloted before they can become programs are listed in Exhibit 6-4. These options will be included in future integrated planning processes after the pilot is completed (See Appendix VI-3 for details about these pilots).

Exhibit 6-4: PILOTED DSM OPTIONS NOT IN PLANNING PROCESS

Residential High Efficiency Ground Coupled Heat Pump
Non-Residential Air Conditioning Load Shift (Cool Storage)
Industrial High Efficiency Dust Collection
Non-Residential Heat Treating Load Shift
Non-Residential Air Conditioning Load Control

6.3.2 Program/Option Descriptions

A brief description of each existing program and new option is given below. Copies of DSM programs and/or rate schedules referenced in these descriptions can be found in Appendix VI-2. Detailed data about each existing program and new option can be found in Appendix VI-4.

Residential High Efficiency Heat Pump Payment

This existing program offers payments to new and existing residential customers who purchase high efficiency heat pumps in accordance with Duke's High Efficiency Heat Pump and Central Air Conditioning Payment Program. By offering a payment to the customer, Duke helps offset the higher purchase cost of more efficient equipment. The installation of high efficiency heat pumps benefits Duke's customers by reducing their overall energy bills.

This program was piloted in two locations in Duke's service area. The availability of the payment for high efficiency heat pumps resulted in a 1.49 SEER increase over a control group during the pilot period. A system-wide program began in July 1991.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Residential High Efficiency Central Air Conditioning Payment

This existing program offers a payment to new and existing residential customers who purchase high efficiency central air conditioners in accordance with Duke's High Efficiency Heat Pump And Central Air Conditioning Payment Program. By offering a payment to the customer, Duke helps offset the higher purchase cost while meeting customers' needs for more efficient cooling equipment. Central air conditioning is the home appliance that makes the largest contribution to Duke's summer peak demand. The installation of high efficiency equipment will benefit Duke's customers by reducing their cooling energy costs.

This program was piloted in two locations in Duke's service area. The availability of the payment on high efficiency central air conditioners resulted in a 1.4 SEER increase during the pilot period. A system-wide program began in July 1991.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Residential Add-On (Dual Fuel) Heat Pump

This existing program targets current fossil fuel heating customers who are adding or replacing central air conditioners in accordance with Duke's Residential Add-On (Dual Fuel) Heat Pump Program. Dual fuel heat pumps are heat pumps which utilize a fossil fuel system instead of electric resistance heat as a supplemental source. Dual fuel heat pumps operate like other heat pumps until the heating demand exceeds the capacity of the compressor. At that point, the compressor shuts off and the fossil system operates exclusively, having no impact on Duke's winter system peak. The customer benefits by installing a high efficiency heat pump which not only operates at much greater efficiency than a fossil furnace during moderate weather, but also provides the customer with high efficiency air conditioning. The higher efficiency system results in lower heating and cooling energy bills for the customer.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Residential High Efficiency Freezer Payment

This existing program offers payments to residential customers who purchase high efficiency freezers in accordance with Duke's High Efficiency Freezer And Refrigerator Payment Program. By offering a payment, Duke helps offset the higher purchase cost and thus encourages customers to obtain more efficient appliances. While freezers have very small individual impacts, approximately 45 percent of Duke's residential customers have freezers. Higher efficiency freezers benefit customers by reducing their total energy bill. This program was implemented across the Duke Power system on June 1, 1991.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Residential High Efficiency Refrigerator Payment

This existing program offers payments to residential customers who purchase high efficiency refrigerators in accordance with Duke's High Efficiency Freezer And Refrigerator Payment Program. By offering a payment, Duke helps offset the higher purchase cost and thus encourages customers to obtain more efficient appliances. Refrigerators have very small individual demand impacts. However, due to the near total market penetration of this appliance, the program's total demand could be significant. High efficiency refrigerators use less energy than standard models and result in lower energy bills for customers. This program was implemented across the Duke Power system on June 1, 1991.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Residential Insulation - New Residences (2% Discount)

The target market for this existing program is new residential single family and multi-family structures that qualify for the RC rate schedule's 2 percent rate discount by meeting all requirements stated in section II of the rate and are therefore considered a Maximum Value Home (MAX). The customer should receive lower energy bills and overall improved comfort due to the required higher levels of insulation and a high efficiency heat pump.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Residential Insulation Loan

This existing program encourages the upgrading of insulation levels in the residential market by making low interest loans available to the customer through Duke's Residential Insulation Loan Program. The target market for this program is all existing residential structures that need thermal integrity improvements. Improved insulation levels benefit customers by lowering their heating and cooling costs and improving their overall comfort levels.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Residential Water Heater Insulating Blanket

This new option provides insulating blankets at no charge to residential customers whose electric water heaters are located in unconditioned areas. These blankets reduce the standby heat loss of water heaters, thus reducing customers' water heating energy consumption. The market penetration for electric water heaters is 84 percent in the Duke service area with approximately half of the devices located in unconditioned areas.

This option was forwarded to the Resource Integration, and will be implemented as a pilot project in 1992.

A detailed description of the pilot project can be found in Appendix VI-3.

Residential High Efficiency Lighting

The new option promotes the use of compact fluorescent lamps which have a substantially longer life and use approximately 75 percent less electricity than standard incandescent bulbs. The residential customer would receive by direct mail a description of the compact fluorescent bulbs and the associated energy saving. The customer may purchase up to three bulbs at a cost less than retail from Duke. Follow-up surveys will be performed to determine customer acceptance of this relatively new product.

This option was originally reviewed in the 1989 planning process. Results indicated that this option should be held for future consideration. Being a very popular option nationally, it was again reviewed as a new option.

This option was not forwarded to the Resource Integration. Because of uncertainties about several of the inputs, this option was implemented as a pilot program in 1991.

A detailed description of the pilot project can be found in Appendix VI-3.

Residential HVAC Tune-Up

This new option is designed to improve the efficiency of existing residential heat pumps and central air conditioning systems by repairing leaks in the duct system, cleaning coils, and correcting refrigerant charge. These repairs benefit the customer by improving comfort and by increasing system efficiency which lowers energy usage. In the Duke service area, 59 percent of residential customers have either heat pumps or central air conditioning systems. The customer would receive direct mail describing the program and the associated costs, the majority of which will be paid by Duke.

This option was forwarded to the Resource Integration and will be implemented as a pilot program in 1992.

A detailed description of the pilot project can be found in Appendix VI-3.

High Efficiency Chillers for Air Conditioning

This new option targets both new and existing commercial and industrial customers to promote the use of high efficiency central chiller equipment that reduces cooling capacity and energy consumption needs. Electric chillers are commonly used for space conditioning in large commercial and industrial facilities.

Targeted customers will be offered a one time payment to offset the higher costs associated with the high efficiency equipment.

A central chiller option is important for several reasons: a wide range of high efficiency machines are available from a number of manufacturers; approximately 25 percent of the conditioned space in the Duke Power service area is cooled by chillers; and finally, the Clean Air Act's phaseout of CFC refrigerants (commonly used in chillers) will command attention and warrant response decisions by owners. As a result, many owners will accelerate their replacement decisions.

The option was forwarded to Resource Integration.

High Efficiency Unitary Equipment for Air Conditioning

This new option promotes high efficiency unitary air conditioning equipment that reduces cooling capacity and energy consumption needs for new and existing customers. Unitary air conditioners are the most common type of space conditioning equipment for commercial and industrial customers. Since major efficiency advances have been limited to smaller machines (less than 5.5 tons), the option concentrates on smaller, non-residential customers with less than 30 kilowatts of metered monthly demand.

Targeted customers will be offered a one time payment to offset the premium costs associated with the high efficiency equipment.

A unitary air conditioner option is important for several reasons: in Duke's service area, approximately 65 percent of the conditioned space is cooled by unitary equipment; over the past decade, strong efficiency advances have been made by manufacturers; and since most non-residential decisions are first cost driven, few high efficiency machines are now in service.

The option was forwarded to Resource Integration.

Non-Residential High Efficiency Indoor Lighting

A non-residential lighting option has been included in each planning process Duke has performed. In every case, the proposed option has not shown satisfactory screening results. A new approach was used which results in a more permanent form of lighting change -- total system replacement.

This new option promotes high efficiency lighting technologies that reduce lighting capacity and energy consumption needs. In this option, Duke offers a one time payment for each kilowatt of demand reduction that the customer can produce by using the high efficiency lighting technology.

Indoor lighting is a major energy component for non-residential facilities. Approximately 35 percent and eight percent of the total energy consumption of commercial and industrial facilities, respectively, is attributed to indoor lighting.

Given the diversity of the market, high efficiency lighting was segmented into six cases for more accurate screening, with each case represented as an individual option. Cases were segmented by new and existing customers and by energy use characteristics: electrically heated, fossil heated, and high usage facilities.

- Case A - Electric Heating - New Market
- Case B - Electric Heating - Existing Market
- Case C - Fossil Heating - New Market
- Case D - Fossil Heating - Existing Market
- Case E - OPT Schedule - New market
- Case F - OPT Schedule - Existing Market

OPT schedule is Duke's time-of-day rate schedule for non-residential customers and was used to identify high usage facilities.

Since market penetration of this option is such a key issue, a second set of case options was included. These options assumed a higher market penetration and were segmented only by energy use characteristics.

- Case G - High Scenario Lighting - Electric Heating
- Case H - High Scenario Lighting - Fossil Heating
- Case I - High Scenario Lighting - OPT Schedule

All cases of this new option were forwarded to Resource Integration. With the uncertainties associated with this option, it was implemented as a pilot program in 1991.

A detailed description of the pilot project can be found in Appendix VI-3.

Motor Systems

This new option targets new and existing industrial customers and promotes the use of energy efficient motors by offering a one time payment per horsepower (HP) of motor replacement. Three case scenarios were developed for the integration process to gauge the value of this option at different market penetration levels with necessary associated payments. Although this option targets industrial customers only, any implemented plan would include all non-residential customers.

	Case A	Case B	Case C
Market Penetration	20%	50%	80%
Payment Per HP	$6/HP	$12/HP	$25/HP

All cases of this new option were forwarded to Resource Integration. Due to the uncertainties associated with this option, it will be implemented as a pilot program in 1992.

A detailed description of the pilot project can be found in Appendix VI-3.

INTERRUPTIBLE PROGRAMS/OPTIONS

Residential Load Control - Air Conditioning

This existing program reduces system capacity requirements by interrupting service to participating residential customers' central air conditioning systems. Participating customers receive credits on their bills from July through October for allowing Duke to interrupt their A/C service when needed. Load control is currently available under rate Rider LC. The program is available to all residential customers with central air conditioners who are served by residential load control equipped substations.

The program was revised. Costs for installation (material and labor) and annual equipment maintenance were updated and applied to all new installations.

The program's estimated accomplishments through 1991 were forwarded to Resource Integration as an existing program for the Updated Plan. Revised future accomplishments were forwarded to Resource Integration as a new option.

Residential Load Control - Water Heating

This existing program reduces system capacity requirements by interrupting service to participating residential customers' water heating system. Participating customers receive a credit on their bill every month for allowing Duke to interrupt service to their water heater when needed. Load control is currently available under rate Rider LC. The program is available to all residential customers with electric water heaters who are served by residential load control equipped substations.

The program was revised. Costs for installation (material and labor) and annual equipment maintenance were updated and applied to all new installations.

The program's estimated accomplishments through 1991 were forwarded to Resource Integration as an existing program for the Updated Plan. Revised future accomplishments were forwarded to Resource Integration as a new option.

Interruptible Service (IS)

This existing program reduces system capacity requirements by purchasing capacity, in the form of load removal, from non-residential customers. Participating customers receive a monthly capacity credit on their bill for their agreement to interrupt their load to a specified contracted level at Duke's request. If a customer fails to comply, he is charged a penalty.

The program is currently available under rate Rider IS.

Due to this program's rapid growth, new customer participation has been temporarily suspended, pending further review to determine its effect on future capacity needs.

The integrated planning process evaluated the value of expanding participation by 500 MW at 100 MW per year in nine different five year periods.

- Case A - Starts the Additions in 1992
- Case B - Starts the Additions in 1993
- Case C - Starts the Additions in 1994
- Case D - Starts the Additions in 1995
- Case E - Starts the Additions in 1996
- Case F - Starts the Additions in 1998
- Case G - Starts the Additions in 2000
- Case H - Starts the Additions in 2003
- Case I - Starts the Additions in 2006

The program's estimated accomplishments through 1991 were forwarded to Resource Integration as an existing program for the Updated Plan. Revised future accomplishments were forwarded to Resource Integration as a new option.

Standby Generator Without Backfeed

This existing program reduces system capacity requirements by having customers with standby generators shift load from Duke's system to their generator. It does not operate in parallel with Duke's system. Therefore, it cannot "backfeed" (export) power onto the Duke system. Participating customers receive a monthly payment for capacity and/or energy, depending on the level of the customer's commitment. This program is available under rate Rider SG. The program is available to all non-residential customers.

The program was not revised for the 1992 IRP.

This program was forwarded to Resource Integration as an existing program for the Updated Plan.

Standby Generator with Backfeed

A standby generator with backfeed option has been included in each integrated planning process Duke has performed. After the 1989 process (as filed in the 1990 Short-Term Action Plan), a pilot project on this option was initiated in early 1990 to investigate concerns about the safety and operational feasibilities.

This new option targets customers who own on-site generation equipment and provides monthly bill credits to these customers for operating their equipment in parallel with Duke's system. The option targets customers who have generation capabilities greater than their facility load. This "excess" generation capacity is exported to the utility power delivery system. The customer's generator must continuously parallel the utility system to allow the export option. Only the incremental (export) capacity was evaluated, since it was assumed that customers qualifying for the option would participate in the existing standby program.

Four case options were reviewed:

- Case A - 500 KW/Customer Exported
- Case B - 1000 KW/Customer Exported
- Case C - 1500 KW/Customer Exported
- Case D - 2000 KW/Customer Exported

All cases of this new option were forwarded to Resource Integration. The pilot project was begun in 1990 to clarify the option's technical challenges: circuit stability, sizing and settings of operational equipment on the utility circuit, proper and safe fault duty protection, etc. The pilot was completed after the start of the Resource Integration process.

A detailed description of the pilot project and results can be found in Appendix VI-3.

Standby Generator - Capacity Improvement

This new option targets customers who participate in the existing Standby Generator Without Backfeed program. This option offers one-time payments to offset the costs for customers to better utilize their generator systems by adding additional facility load to their generators, upgrading their existing generator, or upgrading their existing switch gear.

Three case options were reviewed:

- Case A - $5,000 Payment/Customer
- Case B - $7,500 Payment/Customer
- Case C - $10,000 Payment/Customer

All cases of this new option were forwarded to Resource Integration.

Standby Generator - Category C

This new option is very similar to the Standby Generator with Backfeed option in that it targets customers who own on-site generation equipment, and it provides monthly bill credits to these customers for operating their equipment in parallel with Duke's system. The option only allows the customer's generator to generate capacity equal to the capacity needs of the facility and not to the total capability of the generator. Participants are not allowed to export excess generator capacity onto the utility system.

Since qualified (target) customers must meet several criteria, much uncertainty is associated with the potential market participation. Therefore, additional market research is necessary to quantify this customer participation question. Review of the results of this marketing research and an initial analysis by Resource Integration will determine the option's outcome.

The option was forwarded to Resource Integration.

LOAD SHIFT PROGRAMS/OPTIONS

Residential Controlled Off Peak Water Heating

This existing program shifts a participating customer's water heating usage to off peak periods as determined by Duke. The program is currently available in accordance with rate schedule WC. The program targets new and existing residential customers with electric water heaters located on distribution lines served by load control equipped substations.

Two case options were reviewed:

- Case A - WC submetered lower rate
- Case B - Flat monthly payment

In case A under rate schedule WC, the customer is billed at a lower rate for all water heating energy consumption in exchange for allowing Duke to control their water heater. Case A is the existing program with revised costs associated with the installation (material and labor) and maintenance of the special metering devices.

In Case B, Duke continues to control the customer's water heater, but the customer receives a predetermined monthly bill credit instead of a lower energy rate. Standard metering with a simple load control device is used in place of the special submetering equipment.

The program's estimated accomplishments through 1991 were forwarded to Resource Integration as an existing program for the Updated Plan. The revised future accomplishments for Case A and Case B were forwarded to Resource Integration as new options.

ENVIRONMENTAL PROGRAMS/OPTIONS

A discussion of the need for Duke's involvement in customers' environmental problems/solutions is in Appendix VI-6. Since some solutions have potential impacts on Duke's future capacity and energy requirements, it is appropriate that they be included in the integrated planning process before implementation.

Metal Finishing - Recover Plating Solutions

This new option targets metal plating and circuit board manufacturers because they have stringent federal pre-treatment standards for their discharge water. Duke would aid the customer in determining the most energy efficient method to meet this standard.

A review of EPRI literature, product literature and a consultant's report led to the conclusion that technologies designed to meet the federal standard have technical merit. Also, research should be performed on actual production equipment to quantify the energy impact, operating costs and environmental benefits before a formal option is developed.

The option was not forwarded to Resource Integration.

Textile - Reduction of Waste-Water Effluent

This new option deals with opportunities to improve the quality of waste-water discharge in the textile industry. Opportunities identified by a consultant in a recent research project include:

1. Concentrate waste-water from sizing operations and operations and recover polyvinyl alcohol
2. Reduce BOD level of waste-water
3. Remove color from dyeing effluent

4. Recover of caustic

Reverse osmosis, ultrafiltration, heat pump evaporation and ozonation are technologies which could be employed to improve the quality of textile waste-water.

A review of technology information, literature on textile applications and customer input led to the conclusion that it is premature to develop an option for integration. EPRI has tentative plans to perform research on this subject and Duke will seek active involvement in the project.

The option was not forwarded to Resource Integration.

6.4 Process Results

Results from the Demand-Side process consist of unchanged existing programs, revised existing programs and new options to be used in resource integration. Counting each case of multiple case options, Resource Integration received 12 existing programs for the Updated Plan and 37 revised programs and new options for the integration process. Capacity reduction accomplishments through 1991, projected capacity and energy reductions, and associated projected costs were forwarded to resource integration, and are listed in Appendix VI-5. The following exhibits show the same information for the years 1994, 2000, and 2006. Only the programs for the Updated Plan show estimated accomplishments through 1991. Costs listed in Exhibits 6-6 and 6-7, and in Appendix VI-5 are Duke's direct expenditures.

Existing programs and new options forwarded for use in the Resource Integration (9.0), with abbreviated names, are listed in Exhibit 6-5.

Existing programs that were forwarded for use in the Updated Plan in Resource Integration (9.0) are shown in Exhibit 6-6.

Revised existing programs and new options forwarded to Resource Integration (9.0) are shown in Exhibit 6-7.

The kilowatts (KW) in Exhibits 6-6 and 6-7 are the diversified customer's load at time of Duke's system peak plus transmission and distribution (T&D) line losses. The KW values for each year are cumulative, not incremental. The megawatt-hour (MWH) values are annual values and include T&D line losses. The direct expenditures are annual values. Values in parentheses are reductions.

EXHIBIT 6-5: PROGRAM AND OPTION NAMES - DISPOSITION

Program And Option Names	Abbreviated Name	Existing	Revised	New	Forwarded To Resource Integration		Type
					Updated Plan	New Option	
Residential Load Control - Water Heating	Res LC-W/H						
- Existing Program		XX			XX		I
- Revised Program			XX			XX	I
Residential Load Control - Air Conditioning	Res LC-A/C						
- Existing Program		XX			XX		I
- Revised Program			XX			XX	I
Residential Controlled Off Peak Water Heating							
- Existing Program	Res Off Peak W/H	XX			XX		LS
- WC submetered lower rate	Res Off Peak W/H-Submetered		XX			XX	LS
- Flat monthly payment	Res Off Peak W/H-Flat Pay		XX			XX	LS
High Efficiency Heat Pump Payment	HE Heat Pump-Res	XX			XX		EE
High Efficiency Central Air Conditioning Payment	HE Central A/C-Res	XX			XX		EE
Residential Add-On (Dual Fuel) Heat Pump	Res Duel Fuel HP	XX			XX		EE
High Efficiency Freezer Payment	HE Freezer-Res	XX			XX		EE
High Efficiency Refrigerator Payment	HE Refrig-Res	XX			XX		EE
Residential Insulation - New Residences (2% Discount)	Res Insulation New Resid	XX			XX		EE
Residential Insulation Loan	Res Insulation Loan	XX			XX		EE
Interruptible Service							
- Existing Program	IS	XX			XX		I
- Start the Additions in 1992	IS-Start in 1992		XX			XX	I
- Start the Additions in 1993	IS-Start in 1993		XX			XX	I
- Start the Additions in 1994	IS Start in 1994		XX			XX	I
- Start the Additions in 1995	IS Start in 1995		XX			XX	I
- Start the Additions in 1996	IS Start in 1996		XX			XX	I
- Start the Additions in 1998	IS Start in 1998		XX			XX	I
- Start the Additions in 2000	IS Start in 2000		XX			XX	I
- Start the Additions in 2003	IS Start in 2003		XX			XX	I
- Start the Additions in 2006	IS Start in 2006		XX			XX	I
Standby Generator Without Backfeed	SG W/O Backfeed	XX			XX		I
Residential Water Heater Insulating Blanket	Res W/H Blanket			XX		XX	EE
Residential HVAC Tune-Up	Res HVAC Tune-Up			XX		XX	EE
High Efficiency Chillers for Air Conditioning	HE Chillers for A/C			XX		XX	EE
High Efficiency Unitary Equipment for Air Conditioning	HE Unitary Equip for A/C			XX		XX	EE
Non-Residential High Efficiency Indoor Lighting							
- Electric Heating - Existing Market	Non-Res HE Ltg-El Htg-Existing			XX		XX	EE
- Electric Heating - New Market	Non-Res HE Ltg-El Htg-New			XX		XX	EE
- Fossil Heating - Existing Market	Non-Res HE Ltg-Fossil Htg-Existing			XX		XX	EE
- Fossil Heating - New Market	Non-Res HE Ltg-Fossil Htg-New			XX		XX	EE
- OPT Schedule - Existing Market	Non-Res HE Ltg-OPT-Existing			XX		XX	EE
- OPT Schedule - New Market	Non-Res HE Ltg-OPT-New			XX		XX	EE
- High Scenario Lighting - Electric Heating	Non-Res High-El Htg			XX		XX	EE
- High Scenario Lighting - Fossil Heating	Non-Res High-Fossil Htg			XX		XX	EE
- High Scenario Lighting - OPT Schedule	Non-Res High-OPT			XX		XX	EE
Motor Systems							
- 20% Penetration - $ 6 per Horsepower	Motor Systems-$ 6/HP			XX		XX	EE
- 50% Penetration - $12 per Horsepower	Motor Systems-$12/HP			XX		XX	EE
- 80% Penetration - $25 per Horsepower	Motor Systems-$25/HP			XX		XX	EE
Standby Generator With Backfeed							
- 500 KW/Customer Exported	SG W/Backfeed 500 KW/Cus			XX		XX	I
- 1000 KW/Customer Exported	SG W/Backfeed 1000 KW/Cus			XX		XX	I
- 1500 KW/Customer Exported	SG W/Backfeed 1500 KW/Cus			XX		XX	I
- 2000 KW/Customer Exported	SG W/Backfeed 2000 KW/Cus			XX		XX	I
Standby Generator - Capacity Improvement							
- $ 5,000 Payment/Customer	SG-CIP $ 5,000/Cus			XX		XX	I
- $ 7,500 Payment/Customer	SG-CIP $ 7,500/Cus			XX		XX	I
- $10,000 Payment/Customer	SG-CIP $10,000/Cus			XX		XX	I
Standby Generator - Category C	SG-Cat C			XX		XX	I

I - Interruptible
LS - Load Shift
EE - Energy Efficiency

EXHIBIT 6-6: EXISTING PROGRAMS

PROGRAM	YEAR	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)
	1991	(30,750)	0	
RES LC - W/H (1)	1994	(38,212)	0	3,162,000
	2000	(41,603)	0	3,530,000
	2006	(41,603)	0	3,940,000
	1991	(365,655)	0	
RES LC - A/C (1)	1994	(454,381)	0	11,183,000
	2000	(494,710)	0	12,484,000
	2006	(494,710)	0	13,935,000
	1991	(10,549)	0	
RES OFF PEAK W/H (1)	1994	(13,109)	0	0
	2000	(14,272)	0	0
	2006	(14,272)	0	0
	1991	(1,120)	(2,585)	
HE HEAT PUMP -RES	1994	(3,708)	(8,558)	13,000
	2000	(3,708)	(8,558)	0
	2006	(3,708)	(8,558)	0
	1991	(397)	(484)	
HE CENTRAL A/C - RES	1994	(1,315)	(1,601)	0
	2000	(1,315)	(1,601)	0
	2006	(1,315)	(1,601)	0
	1991	(851)	1,122	
RES DUAL FUEL HP	1994	(24,256)	30,438	5,439,000
	2000	(36,491)	45,762	0
	2006	(36,491)	45,762	0

(1) Energy changes are negligible and assumed to be zero
(2) Estimated cumulative values
(3) Estimated annual values

NOTE: Parentheses indicate reductions

EXHIBIT 6-6: EXISTING PROGRAMS (con't)

PROGRAM	YEAR	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)
HE FREEZER - RES	1991	(41)	(540)	
	1994	(239)	(1,844)	52,000
	2000	(239)	(1,844)	0
	2006	(239)	(1,844)	0
HE REFRIG - RES	1991	(77)	(856)	
	1994	(449)	(2,909)	23,000
	2000	(449)	(2,909)	0
	2006	(449)	(2,909)	0
RES INSULATION NEW RESID.	1991	(7,552)	32,834	
	1994	(20,210)	87,864	5,496,000
	2000	(74,585)	324,269	6,783,000
	2006	(74,585)	324,269	478,000
RES INSULATION LOAN	1991	0	0	
	1994	(678)	(16,463)	1,013,000
	2000	(1,131)	(27,438)	0
	2006	(1,131)	(27,438)	0
IS (1)	1991	(566,455)	0	
	1994	(566,455)	0	25,580,000
	2000	(566,455)	0	26,357,000
	2006	(566,455)	0	27,158,000
SG W/O BACKFEED (1)	1991	(28,031)	0	
	1994	(54,431)	0	2,348,000
	2000	(92,731)	0	5,447,000
	2006	(110,131)	0	10,141,000

(1) Energy changes are negligible and assumed to be zero
(2) Estimated cumulative values
(3) Estimated annual values

NOTE: Parentheses indicate reductions

EXHIBIT 6-7: REVISED EXISTING PROGRAMS AND NEW OPTIONS

PROGRAM	YEAR	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)
RES LC - W/H (1)	1994	(7,985)	0	2,303,000
	2000	(23,907)	0	4,801,000
	2006	(28,631)	0	4,252,000
RES LC - A/C (1)	1994	(228,477)	0	11,042,000
	2000	(684,021)	0	26,936,000
	2006	(859,143)	0	32,811,000
RES W/H BLANKET	1994	(2,738)	(30,954)	926,000
	2000	(4,694)	(53,065)	0
	2006	(4,694)	(53,065)	0
RES HVAC TUNE-UP	1994	(5,541)	(11,470)	2,756,000
	2000	(51,174)	(105,930)	0
	2006	(51,174)	(105,930)	0
HE CHILLERS FOR A/C	1994	(8,882)	(21,655)	1,663,000
	2000	(43,775)	(106,729)	3,083,000
	2006	(70,421)	(171,695)	1,397,000
HE UNITARY EQUIP. FOR A/C	1994	(4,921)	(3,598)	651,000
	2000	(19,147)	(13,998)	900,000
	2006	(33,463)	(24,463)	1,042,000
NON-RES HE LTG-EL HTG-EXISTING	1994	(26,858)	(78,258)	3,171,000
	2000	(107,434)	(313,032)	3,573,000
	2006	(188,009)	(547,805)	4,030,000
NON-RES HE LTG-EL HTG-NEW	1994	(12,323)	(35,906)	1,532,000
	2000	(49,293)	(143,625)	1,726,000
	2006	(86,263)	(251,345)	1,947,000
NON-RES HE LTG-FOSSIL HTG-EXISTI	1994	(25,669)	(109,359)	3,164,000
	2000	(102,674)	(437,435)	3,581,000
	2006	(179,680)	(765,511)	4,059,000
NON-RES HE LTG-FOSSIL HTG-NEW	1994	(24,726)	(105,344)	3,207,000
	2000	(98,905)	(421,377)	3,629,000
	2006	(173,084)	(737,409)	4,112,000
NON-RES HE LTG-OPT-EXISTING	1994	(13,423)	(86,176)	1,520,000
	2000	(53,693)	(344,704)	1,710,000
	2006	(93,963)	(603,233)	1,925,000

(1) Energy changes are negligible and assumed to be zero
(2) Estimated cumulative values
(3) Estimated annual values

NOTE: Parentheses indicate reductions

EXHIBIT 6-7: REVISED EXISTING PROGRAMS AND NEW OPTIONS (con't)

PROGRAM	YEAR	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)
NON-RES HE LTG-OPT-NEW	1994	(2,992)	(19,210)	357,000
	2000	(11,969)	(76,838)	402,000
	2006	(20,945)	(134,467)	452,000
NON-RES HIGH-EL HTG	1994	0	0	0
	2000	(274,434)	(782,103)	26,956,000
	2006	(548,867)	(1,564,207)	30,327,000
NON RES HIGH-FOSSIL HTG	1994	0	0	0
	2000	(274,696)	(1,180,834)	26,959,000
	2006	(549,392)	(2,361,668)	30,331,000
NON-RES HIGH-OPT	1994	0	0	0
	2000	(96,953)	(603,194)	9,519,000
	2006	(193,906)	(1,206,389)	10,710,000
	1994	(24,359)	(142,095)	23,170,000
MOTOR SYSTEMS - $6/HP	2000	(170,513)	(994,667)	28,447,000
	2006	(267,948)	(1,563,047)	0
	1994	(60,897)	(355,238)	75,800,000
MOTOR SYSTEMS - $12/HP	2000	(426,281)	(2,486,665)	93,896,000
	2006	(669,871)	(3,907,616)	0
	1994	(97,436)	(568,380)	217,849,000
MOTOR SYSTEMS - $25/HP	2000	(682,050)	(3,978,663)	270,545,000
	2006	(1,071,793)	(6,252,185)	0
IS-START IN 1992 (1)	1994	(283,227)	0	13,541,000
	2000	(472,046)	0	22,987,000
	2006	(472,046)	0	23,840,000
IS-START IN 1993 (1)	1994	(188,818)	0	9,110,000
	2000	(472,046)	0	22,987,000
	2006	(472,046)	0	23,840,000
IS-START IN 1994 (1)	1994	(94,409)	0	4,717,000
	2000	(472,046)	0	22,987,000
	2006	(472,046)	0	23,840,000
IS-START IN 1995 (1)	1994	0	0	0
	2000	(472,046)	0	22,987,000
	2006	(472,046)	0	23,840,000

(1) Energy changes are negligible and assumed to be zero
(2) Estimated cumulative values
(3) Estimated annual values

NOTE: Parentheses indicate reductions

EXHIBIT 6-7: REVISED EXISTING PROGRAMS AND NEW OPTIONS (con't)

PROGRAM	YEAR	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)
IS-START IN 1996 (1)	1994	0	0	0
	2000	(472,046)	0	23,208,000
	2006	(472,046)	0	23,840,000
IS-START IN 1998 (1)	1994	0	0	0
	2000	(283,227)	0	14,051,000
	2006	(472,046)	0	23,840,000
IS-START IN 2000 (1)	1994	0	0	0
	2000	(94,409)	0	4,925,000
	2006	(472,046)	0	23,840,000
IS-START IN 2003 (1)	1994	0	0	0
	2000	0	0	0
	2006	(377,636)	0	19,366,000
IS-START IN 2006 (1)	1994	0	0	0
	2000	0	0	0
	2006	(94,409)	0	5,155,000
SG W/BACKFEED 500 KW/CUS (1)	1994	(2,716)	0	169,000
	2000	(4,346)	0	206,000
	2006	(5,976)	0	320,000
SG W/BACKFEED 1000 KW/CUS (1)	1994	(5,432)	0	261,000
	2000	(8,692)	0	370,000
	2006	(11,951)	0	571,000
SG W/BACKFEED 1500 KW/CUS (1)	1994	(8,149)	0	352,000
	2000	(13,038)	0	534,000
	2006	(17,927)	0	823,000
SG W/BACKFEED 2000 KW/CUS (1)	1994	(10,865)	0	444,000
	2000	(17,384)	0	698,000
	2006	(23,903)	0	1,075,000
SG-CIP $5000/CUS (1)	1994	(3,259)	0	173,000
	2000	(5,432)	0	210,000
	2006	(5,432)	0	235,000
SG-CIP $7500/CUS (1)	1994	(3,259)	0	200,000
	2000	(5,432)	0	210,000
	2006	(5,432)	0	235,000
SG-CIP $10000/CUS (1)	1994	(3,259)	0	227,000
	2000	(5,432)	0	210,000
	2006	(5,432)	0	235,000

(1) Energy changes are negligible and assumed to be zero
(2) Estimated cumulative values
(3) Estimated annual values

NOTE: Parentheses indicate reductions

EXHIBIT 6-7: REVISED EXISTING PROGRAMS AND NEW OPTIONS (con't)

PROGRAM	YEAR	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)
SG-CAT C (1)	1994	(9,778)	0	576,000
	2000	(22,816)	0	1,115,000
	2006	(27,705)	0	1,428,000
RES OFF PEAK W/H-SUBMETERED	1994	(3,457)	5,288	1,069,000
	2000	(10,370)	15,863	1,612,000
	2006	(10,370)	15,863	526,000
RES OFF PEAK W/H-FLAT PAY	1994	(3,753)	5,288	1,794,000
	2000	(6,255)	8,813	2,105,000
	2006	(6,255)	8,813	2,379,000

(1) Energy changes are negligible and assumed to be zero
(2) Estimated cumulative values
(3) Estimated annual values

NOTE: Parentheses indicate reductions

6.5 Other DSM Related Activities

6.5.1 Pilot Projects

Demand-side options have uncertainties associated with their capability to meet customer and utility system requirements. These factors consist of both technical and non-technical issues. The non-technical issues include customer preference and behavior, effectiveness of program marketing/distribution channels and program costs. The technical issues include system load shape impacts, training for Duke personnel, and additional metering or communications equipment needed.

Pilot projects are undertaken to address the factors of uncertainty associated with a DSM option. Pilot projects involve the introduction of an option into the marketplace in some limited fashion to gauge the impact in a controlled environment. Results are used to determine whether the option needs to be redesigned or re-evaluated. Work teams are formed with representatives from various departments to develop the specifics of the pilot projects. Being a collaborative process, pilot projects encourage ownership and buy-in from entities directly involved with the project.

The eleven options currently being piloted are shown in Exhibit 6.8. It was determined that these should be piloted to address various uncertainties before they could be introduced to the marketplace as a full program. See Appendix VI-3 for a detailed description of each pilot.

The targeted milestones in the exhibit reflect the quarter and year of completion.

Exhibit 6-8: 1992 Demand Side Pilot Projects

PILOT	OBJECTIVES	MILESTONES	
I. Residential Pilots			
A. High Efficiency Lighting	To test customer acceptance of compact fluorescent bulbs, target market response, and the feasibility of using a fulfillment house as distribution tool.	Res. - Comp Design - Comp	Implem - Comp Eval. - 2/92
B. High Efficiency Ground Coupled Heat Pump	To encourage the installation of ground coupled heat pumps on the Duke system. Installation costs, market potential, and load shapes will be determined.	Res. - Comp Design - Comp	Implem - 4/92 Eval. - 2/93
C. HVAC Tune-Up	To investigate the demand and energy reductions associated with repairing A/C and heat pump systems that are experiencing operational problems.	Res. - 2/92 Design - 2/92	Implem - 3/92 Eval. - 2/93
D. Water Heater Insulating Blanket	To promote the installation of water heater blankets, reducing the losses associated with lower levels of insulation.	Res. - Comp Design - Comp	Implem - 2/92 Eval. - 3/92
II. Commercial/Industrial Pilot			
A. Non-Residential Air Conditioning Load Shift (Cool Storage)	To promote cool storage technologies in the Duke service area. Customer economics and load shape data will be collected.	Res. - Comp Design - Comp	Implem - 4/92 Eval. - 2/93
B. Non-Residential Heat Treating Load Shift	To investigate the potential for convincing customers to shift heat treating process loads to off peak hours.	Res. - Comp Design - Comp	Implem - Comp Eval. - Comp
C. Industrial High Efficiency Dust Collection	To investigate the potential for convincing furniture manufacturers to install hi-efficiency dust collection systems for demand and energy reductions.	Res. - Comp Design - Comp	Implem - Comp Eval. - Comp
D. Non-Residential High Efficiency Indoor Lighting	To determine the feasibility of a full scale program convincing the installation of hi-efficiency indoor lighting technology in the commercial/industrial markets.	Res. - 3/92 Design - 4/92	Implem - 2/94 Eval. - 4/94
E. Motor Systems	To improve the efficiency and effectiveness of motors in meeting specific end-use applications.	Res. - 4/92 Design - TBD	Implem - TBD Eval. - TBD
F. Non-Residential Air Conditioning Load Control	To evaluate the operating characteristics and customer acceptance of an interruptible program for non-residential air conditioning systems.	Res. - Comp Design - Comp	Implem - Comp Eval. - 2/92
G. Standby Generator With Backfeed	To evaluate the technical feasibility of allowing parallel connections of customer owned generation to the Duke Power system.	Res. - Comp Design - Comp	Implem - Comp Eval. - Comp

Res - Research; Implem - Implementation; Eval - Evaluation; Comp - Completed
The milestones reflect the quarter and year of phase completion.

6.5.2 DSM Resource Assessment

Duke is performing a DSM Resource Assessment. The results will aid in DSM option and program planning and program evaluation. This section is a status report of the assessment since final results will not be available until 1993.

A DSM Resource Assessment determines the total technical potential for a set of demand-side options for the existing market and for the new construction market. This total represents the maximum available energy and demand savings from reasonable options, without the limitations that are normally associated with these options. Such limitations are costs, customer participation rates, etc.

Duke participated in a collaborative effort headed by the North Carolina Alternative Energy Corporation (NCAEC) to perform a state-wide assessment of the state's demand-side peak load and energy reduction potentials. Three documents emerged as a result of this collaboration: (1) "Characteristics of Selected DSM Technologies and Measures"; (2) "A Guidebook for Conducting a Demand-Side Management Resource Assessment"; and (3) "Summary of DSM Program Experience". The first document was used as the initial list of DSM options to be included. The other two documents are to be used to supplement research within the framework of Duke's view of the DSM assessment.

The "Characteristics" option list has been reviewed and amended to produce the following Residential and Commercial/Industrial Option lists.

RESIDENTIAL OPTIONS

1. Building Envelope Insulation Additions/Standards
   - A. Roof
   - B. Walls
   - C. Floor
   - D. Windows
2. Appliances
   - A. Water Heater
     - 1) Insulation Blanket - Existing Only
     - 2) Replacement with High Efficiency Standard
     - 3) Heat Pump Water Heater
   - B. Freezers/Refrigerators - High Efficiency
   - C. Residential Lighting - Compact Fluorescent Lamps
3. HVAC
   - A. A/C - High Efficiency - SEER Change - Central/Room
   - B. Heat Pumps
     - 1) High Efficiency - SEER/HSPF Change
     - 2) Ground Couple HP
     - 3) Variable Speed HP
     - 4) Water Source HP
     - 5) Dual Fuel HP
   - C. HVAC Tune-ups

4. Load Shift

    A. Water Heater Off Peak
    B. Cool Storage
    C. Heating Storage

5. Interruptible

    A. Water Heater DLC
    B. A/C DLC
    C. Pool Pump DLC

6. Other

COMMERCIAL/INDUSTRIAL OPTIONS

1. Building Envelope - Insulation Changes/Standards

    A. Roof
    B. Walls
    C. Floor
    D. Windows

2. Lighting

    A. Commercial/Industrial "Office"
        1) Energy Efficient Fluorescent Lamps and Ballasts
        2) Ellipsoidal Incandescent Lamps
        3) Day Lighting
    B. Industrial/Warehouse High Bay - HID Lighting Sources

3. Refrigeration

    A. High Efficiency Compressors
    B. Compressor Systems

4. Industrial/Commercial Motors

    A. High Efficiency Motors
    B. Adjustable Speed Drives

5. Commercial/Industrial HVAC

    A. A/C
        1) High Efficiency - SEER Change
        2) Chiller Efficiency Improvement
    B. Heating
        1) High Efficiency - SEER and HSPF Change
        2) Specialty Heat Pumps - Water Loop, Packaged Terminal, Etc.
        3) Dual Fuel Heat Pumps

6. Water Heating

    A. Heat Pump Water Heater
    B. Recovery Water Heating (Desuperheaters)

7. Ventilation

   A. Preconditioning
      1) Heat Pipes
      2) Heat Wheels
   B. Filtration
   C. Kitchen Hoods

8. Load Shift

   A. Commercial Cool Storage
   B. Commercial Heat Storage
   C. Industrial/Commercial End-Use Loads

9. Interruptible

   A. Commercial A/C DLC
   B. Commercial/Industrial Standby Generator
      1) Isolated Operation
      2) Parallel Operation
   C. Industrial/Commercial I/S (Interruptible Service)
   D. Warehouse HID Bi-Level Ballast

10. Other

In connection with the creation of this list, data needs were identified and assessment assumptions were formulated. Beginning in 1991 and continuing into 1992 and 1993, needed data will be obtained from several sources, two of which are surveys and end-use metering. A multitude of customer, trade ally, manufacturer, construction, and other surveys were identified. Duke's goal is to conduct these surveys in a manner considered least objectionable to our customers and still provide meaningful information. Most of the end-use metered data will be obtained from the Residential/Commercial End-Use Metering Project, a discussion of which may be found in section 6.5.3.

In 1992, a consultant will be hired to perform the engineering analysis and, from the guidelines and data, generate the final report. The first assessment document will be completed in 1993. With the establishment of the data collection processes and the completion of the first document, a study will be done to determine the need for additional assessments and the timetable for any such assessments.

6.5.3 End-Use Metering

One of the data needs identified for use in many integrated planning areas (such as end-use forecasting, option development, resource assessment, and program evaluation) was metered end-use load shapes. Therefore, the Residential/Commercial End-Use Metering Project was begun in the second quarter of 1990. The purpose of this project is to obtain, process, and analyze end-use electrical data for customer-owned appliances, equipment, processes and systems. The raw data can then be applied to a procedure directly or used to develop annual hourly load shapes.

This project involves a total of 500 customer sites (200 residential and 300 commercial). Installations began in early 1991 and the 500 original customer site installations were completed in August 1991. Since that time, approximately 25 sites have been or are being installed as replacements. The project is scheduled to continue through December 1993. The residential group was designed to be divided into three groups. Single family residences constitute approximately one-half of the sites. Apartments (including condominiums) and manufactured housing comprise the other half equally. Commercial sites include 20 customer classifications:

Classification	Approximate Number
Small Office	50
Medium Office	35
Large Office	10
Education	50
Small Retail	42
Large Retail	20
Malls	5
Food Stores	6
Convenience Stores	6
Fast Food Restaurants	10
Other Restaurants	10
Hospitals	2
Nursing Homes	3
Hotels/Motels	12
Warehouses	8
Churches	5
Amusement	8
Personal Services	5
Communication	5
Transportation	8

The Residential and Commercial customers were selected to cover a range of structure energy consumptions and to be evenly divided between customers with and without electric heat. Also, an alternate sample of customers is maintained to be used as replacements for customers that do not remain in the project for the duration. All customer sites are within a 30 mile radius of either Charlotte or Greensboro.

An outside contractor was engaged to:

1. help in obtaining customer participation
2. collect demographic and end-use survey data
3. install the monitoring equipment
4. maintain the equipment during the project
5. install replacements
6. remove the equipment

End-use metering will also be used in several other projects: pilots, program evaluation, and industrials. In pilots, end-use metering will provide a means to show what a particular end-use is doing, determine before and after differences, compare different systems, and so on. Program evaluation will use end-use metering to evaluate actual program results, i.e. are the programs doing what they are designed to do?

Because industrial end-use metering offers a unique challenge, negotiations are underway for a test installation of a few end-uses. The installation should be started, if not completed, in 1992. Other uses for industrial end-use metering will be explored in 1992. Because the potential for end-use metering in the industrial market is almost exclusively process-specific, industrial class-specific or even plant/location-specific, the metering will be done only on a selective basis and will not be on the broad scale used in the Residential/Commercial project.

6.5.4 DSM Research, Development, & Demonstration (RD&D)

New technologies, new concepts of energy usage, and new issues affecting the environment surface regularly. With RD&D, Duke has a means to review, demonstrate, and evaluate these new ideas. RD&D provides the mechanism to review manufacturer's data and validate the data that is needed to be used in DSM option development. RD&D provides the opportunity to use "hands on" installations to demonstrate DSM potential. The data from this demonstration may be used to develop a DSM option or to sell the customer on the DSM program. Sometimes, a new DSM idea is presented, but has many risks and uncertainties that must first be addressed. Again, RD&D is where this idea is evaluated before it is incorporated in the integrated planning process as a DSM option. The evaluation data would not only be the determining factor for inclusion, but would be input data for option development.

A RD&D history and a brief description of DSM related RD&D projects is in Appendix VI-7.

6.5.5 Targeted DSM

A project is underway to investigate the potential of using DSM programs to relieve localized problems on the transmission and distribution system. The objective is to concentrate the implementation of specific DSM programs within a particular geographical area to offset the need for capital improvements to the transmission and distribution system.

Two substations have been selected as test sites. Electrical and demographic information will be collected to assist in selecting the most effective demand side programs. The effectiveness of the test will be used to determine the system-wide potential of using targeted DSM to defer capital expenditures on the transmission and distribution systems.

7.0 SUPPLY SIDE RESOURCES

7.1 Introduction

The purpose of this section is to describe the identification and assessment of potential supply-side generation technologies. This section will also describe the screening process used to evaluate the technology options and identify those options forwarded to subsequent phases of the integrated planning process. This section concludes with a discussion of emerging supply-side issues and the impact of these issues on this Integrated Resource Plan.

Supply-Side studies provide generation options and plant construction requirements needed to meet the electrical needs of Duke's customers. The supply-side options represent the most cost effective type of generation. These costs also dictate thresholds for DSM options or purchased power agreements with other utilities or non-utility generators.

Duke has a number of supply-side options available to meet new generation needs. These options are divided into three main categories:

- Refurbishment of existing generating units,
- Enhancements to existing generating units to increase output capability,
- New generating units.

Refurbishment

Duke is pursuing a Plant Modernization Program (PMP). PMP is currently expected to restore both reliability and availability of selected older units. Modernization of these units reduces our need to construct additional resources. Reference Section 4.4 for the refurbishment schedule. The PMP is not intended nor expected to increase the capacity of the subject units.

Enhancements

Enhancements to existing generating units are analyzed for their effects on the Duke system. Efficiency improvements are continually being implemented, but may not result in sizable changes to unit capability. Presently there are no planned changes to existing generating units which would increase or decrease capability by either 10 percent or 10 MW.

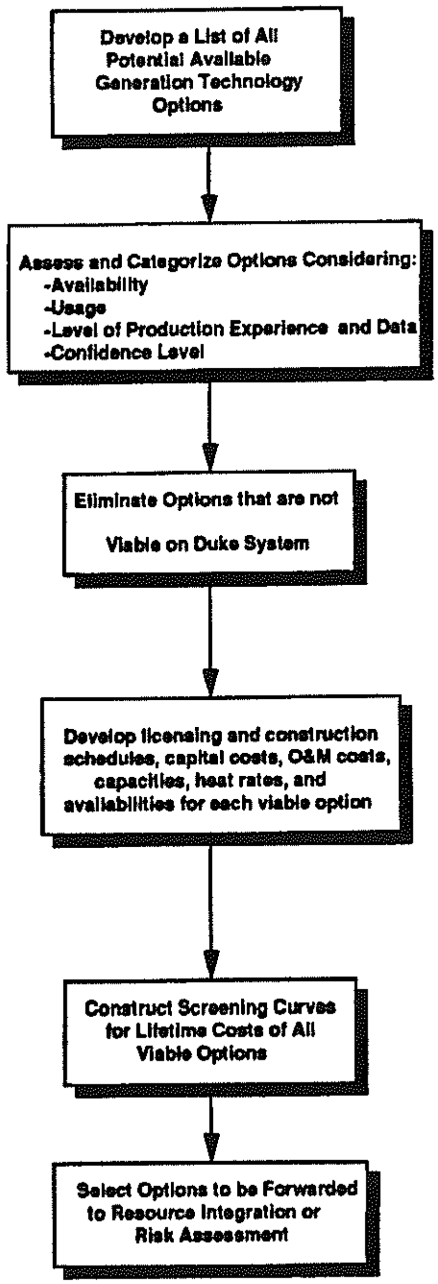
New Generating Units

The selection of new generating options is a complex process. There are a number of viable technologies available, each with its own unique set of operating and cost parameters. Selecting the best technologies involves a multiple-step procedure, beginning with the identification of options, continuing through initial screening, and culminating in integration with other resources. The initial steps in this process, including identification of options and initial screening, are described in this section. Incorporation of these resources in the planning process is described in Resource Integration (9.0) and Risk Assessment (10.0).

7.2 Process Overview

This process identifies viable technologies; develops corresponding schedule, cost, and performance data; and performs cost screening to select low-cost and cost-competitive generation resources. This process is graphically illustrated in Exhibit 7-1.

Exhibit 7-1: SUPPLY-SIDE PROCESS DIAGRAM



Technology Options Investigations

A broad array of generation technologies are initially considered, with the total number of technologies varying from year to year as potential new technologies are identified, or as previously considered options are found to be impractical.

Development of Schedule, Cost, and Performance Data

The following information is developed for those generation technologies which are determined to be viable options in the Duke service area:

- Licensing and construction schedule durations
- Estimated capital costs
- Estimated operation and maintenance costs
- Net generation capacities and anticipated heat rates
- Maintenance/Overhaul outage schedules and resulting availabilities

In order to compare the technology options in a consistent manner, several assumptions are used in performing the investigations above:

- Construction Work In Progress (CWIP) is not applicable
- All cost estimates are performed in 1991 dollars with the anticipated cash flows escalated at 5.5 percent per year
- Allowance for Funds Used During Construction (AFUDC) is added to the escalated cash flows
- Commercial operation dates assume a January, 1991 start for licensing and engineering work at a Duke-owned, management-approved site

The results for all viable options are segregated into groups of comparable technologies and subjected to a detailed screening process.

Screening Analysis

In order to determine cost-effective generation technologies for expanding the Duke system, a screening-curve analysis is performed. This analysis includes 29 technologies plus multiple unit sizes for various options.

Screening-curve analyses examine the cost for specific generation technologies. Parameters such as capital, fuel, and maintenance costs previously developed are included. The relative expense of these parameters can be illustrated graphically on an individual basis or as a composite curve. These parameters are incorporated into a present worth of revenue requirement (PWRR) analysis as of the year 2000 over a range of capacity factors to create screening curves for each viable generation technology.

Screening curve analyses are not designed to examine interactions with the existing generation system or to consider unit availability. This method is used only to eliminate those technologies which are clearly not cost effective, thus reducing the number evaluated in the subsequent detailed analysis.

Selection of Options

Based on their ranking in the screening phase, generation technologies are chosen to be included in Resource Integration (9.0) or in Risk Analysis (10.0).

7.3 Available Options

Potential generation technologies are categorized as follows:

7.3.1 Conventional Technologies

This classification is applied to those technologies that are well understood, widely used, and have a long track record in the electric utility industry. There is a large, well developed infrastructure to support the technology, and executives and investors have a high level of confidence in the technical and commercial viability of the technology. While these have been modified and enhanced over the years, the basic technology has been applied for several decades. These technologies include:

Conventional Pulverized Coal

These plants utilize conventional pulverized coal (PC) boilers and turbine generators and applicable pollution control equipment including precipitators, scrubbers, cooling towers, ash and scrubber sludge handling and disposal. All units assume new site location. Six PC facilities are considered:

- a 400 MW subcritical unit designed for cycling duty
- an 800 MW subcritical unit designed for intermediate load (capable of being cycled)
- a 1200 MW facility with 2-600 MW subcritical units designed for base load
- a 1200 MW facility with 3-400 MW subcritical units designed for base load
- a 1200 MW facility with 2-600 MW supercritical units designed for base load
- a 1200 MW supercritical unit designed for base load

Light Water Nuclear (LWR)

Nuclear generation is considered to be available in the future despite the current hiatus on building nuclear plants. The plant is based on "evolutionary" reactor design requirements being developed by the industry advanced LWR Program sponsored by the Electric Power Research Institute (EPRI). LWR is considered as a Conventional Technology since its design is based on existing proven techniques. Evolutionary features will address new licensing issues and utility needs for increased public safety, investment protection, operational flexibility, reduced cost and ease of maintenance. The representative plant is 1200 MW.

Pumped Storage Hydroelectric

Pumped storage hydroelectric costs are based on a two-unit, 800 MW site and a four-unit, 1600 MW site similar in design to Bad Creek. Because there is a cost advantage to plants located on existing reservoirs, the next unit is assumed to be so located.

Combustion Turbine

80 MW combustion turbine units (74 MW summer rating in the Duke Service area) are used in a 16 unit facility and a 12 unit facility. The units are vendor supplied with Duke providing fuel tanks, certain auxiliary systems, land, substation, and construction support services. The units are assumed to be dual fueled (fuel oil and natural gas).

Combined Cycle

Combined cycle units are based on a single unit, 400 MW facility. The unit is vendor supplied with Duke providing foundations, site clearing, licensing, cooling tower basins and site improvements. The unit includes two combustion turbines, one heat recovery steam generator and one steam turbine.

Oil-Fired Boiler

Oil-fired boiler costs are based on a single unit, 400 MW facility. The unit is vendor supplied with Duke providing licensing, site clearing, foundations and site improvements. The facility includes an oil-fired boiler to generate steam which drives a conventional turbine-generator.

Gas-Fired Boiler

Gas-fired boiler costs are based on a single unit, 400 MW facility. The unit is vendor supplied with Duke providing licensing, site clearing, foundations and site improvements. The facility includes a gas-fired boiler to generate steam which drives a conventional turbine-generator.

Diesel Generator

Diesel-generator costs are based on a 16-unit, 25.6 MW facility with NOx control. The units are vendor supplied with Duke providing fuel tanks, certain auxiliary systems, land, substation, and construction support services.

Conventional Hydroelectric

Conventional Hydroelectric is a conventional technology that is not viable. There are no sites available within the Duke service area for a conventional hydroelectric station that provide a cost-effective increment of capacity.

7.3.2 Demonstrated Technologies

This classification is applied to those technologies which are one or few of a kind, and have not achieved widespread acceptance or use within the electric utility industry. These technologies do not have a well developed infrastructure to support them and the confidence level among utility executives and investors is low in terms of technical and commercial viability. These technologies include:

Atmospheric Fluidized Bed Combustion (AFBC)

In this technology, crushed coal is burned with limestone in an atmospheric pressure fluid bed suspended by air blown in from below. The calcium in the limestone captures most of the sulfur released from the coal during combustion. Particulates are captured in a series of cyclones followed by an electrostatic precipitator. Steam is produced inside tubes passing through the bed and/or through the hot gas stream. The steam is used to drive a conventional steam turbine generator. The fluid boiler design is based on the "bubbling bed" concept and a single 400 MW unit.

Circulating Fluidized Bed Combustion (CFBC)

Circulating fluidized bed combustion is a variation of the AFBC concept. CFBC is characterized by fluidization velocities of 15 to 30 ft./sec. while the AFBC "bubbling bed" fluidization velocity is 5 to 12 ft./sec. This enables the CFBC plant to maintain a continuous high-volume recycle of small solid particles (fines) consisting of coal, limestone and combustion products. This recycle system retains fuel and limestone fines thereby increasing their utilization. Unlike "bubbling bed" furnaces which contain heat transfer surfaces within the bed, CFBC heat transfer takes place outside the bed. Exhaust gas particulate control is provided by a filter baghouse. The CFBC plant consist of four 100 MW units.

Advanced Combustion Turbine

The new generation of high capacity 150 MW (128 MW summer rating in the Duke Service area) combustion turbine units are used in a six unit facility. The units are vendor supplied with Duke providing fuel tanks, certain auxiliary systems, land, substation, and construction support services. The units are assumed to be dual fueled (fuel oil and natural gas).

Gasification/Combined Cycle

In this technology, pulverized coal in a concentrated water slurry is pumped into an entrained flow gasifier where a partial oxidation process produces an intermediate BTU gas (CA 300 BTU/SCF). After the gas passes through a heat recovery section, the sulfur and nitrogen compounds and particulates are removed, and the clean gas is fired in a combustion turbine (at 1900° Fahrenheit for conventional turbines and 2250° for advanced turbines). The hot exhaust gases generate steam in heat recovery boilers. The steam is used to drive both a steam turbine generator and steam turbine compressors in the oxygen plant. The sulfur compounds are reduced to elemental sulfur in a Claus plant. The representative plant has a capacity of 400 MW.

Fuel Cells (Various Types)

Solid Oxide Fuel Cells: Solid oxide fuel cells employ a solid, nonporous metal oxide electrolyte which allows ionic conductivity by the migration of oxygen ions through the lattice of the crystal. These cells accept hydrogen and carbon monoxide at the anode and oxygen at the cathode. Oxygen plus hydrogen form water at the anode, liberating electrons. These cells operate at about 1000° Celsius. Fuel versatility is the major advantage of these cells. The representative solid oxide fuel cell plant consists of one unit at 200 MW.

Phosphoric Acid Fuel Cells: Dispersed fuel-cell power plants are modular units composed of three major subsystems: (1) the fuel processor, (2) the power section, and (3) the power conditioner. The fuel processor reforms the light distillate fuel or other liquid or gaseous fuel into a hydrogen-rich gas. The power section (composed of fuel-cell stacks) converts the hydrogen with oxygen from ambient air into water and electricity. The power conditioner converts DC power to AC power compatible with the utility bus. The first generation fuel-cells use phosphoric acid as the electrolyte. A typical fuel-cell plant would consist of three 10 MW units.

Molten Carbonate Fuel Cells: Molten carbonate fuel cells convert methane to hydrogen and carbon monoxide at the anode. Oxygen and carbon dioxide are fed to the cathode, reacting to form carbonate ions which are conducted through the electrolyte to react at the anode to form carbon dioxide, water and electrons. A typical molten carbonate fuel cell plant would consist of three 10-MW units.

Municipal Refuse Steam Systems

Municipal Refuse Steam (Mass Burn): Municipal solid waste (MSW) is a low quality fuel with low heat and high ash and moisture contents, typically, 4500 Btu/lb. It can be fired on a moving grate in a waterwall incinerator to produce steam for industrial use, cogeneration, or electricity generation. Ferrous metal can be recovered from the ash residues from the incinerator. The incineration plant consists of 8 operating and 2 spare units to allow planned maintenance without affecting steam generating capacity. The representative MSW plant consists of one unit at 45 MW.

Refuse Derived Fuel (RDF): To increase the BTU content of municipal solid waste, RDF facilities separate the waste stream into combustible and non-combustible components. The non-combustible stream is recycled or is land filled, and the combustible stream is used to fire a boiler either as the sole fuel or in combination with fossil fuels. The representative RDF plant consists of one unit at 45 MW.

Modular Mass Burn: Modular mass burn facilities are shop fabricated facilities whose major attribute is the savings in construction time. Otherwise, these facilities are equivalent to the conventional mass burn waste-to-energy facilities. The representative modular mass burn plant consists of one unit at 45 MW.

Lead Acid Battery Storage System

Off-peak electric power is used to charge an improved lead-acid battery or an advanced battery based on either the sodium-sulfur or the zinc-chlorine system. The battery system is composed of modular units, each with a three hour storage capacity. Battery capital costs are based on a production rate of ten-20 MW units per year for lead-acid and twenty-five-20 MW units per year for the advanced battery. The battery facility evaluated here utilizes a 20 MW unit.

Wind Power

The kinetic energy in a moving airstream (wind) is used to drive a turbine, which in turn drives an electrical generator. In a representative current horizontal-axis design, a double-bladed motor of 100 feet in diameter is mounted at its center to a 200-foot cylindrical tower. A representative rating is 0.522 megawatts, but machines rated up to 4 megawatts are under development in the United States and even larger designs are being studied internationally. The wind generating facility considered utilizes 250 units of 0.522 MW each, for a total of 150 MW.

Compressed Air Energy Storage (CAES)

Compressed air energy storage is based on using an electric motor driven compressor to pressurize air in an underground, conventionally mined, rock cavern during off-peak periods. When the stored energy is needed, the air is combined with fuel and ignited. Combustion gases expand and power a combustion turbine/generator. A surface water reservoir is connected to the underground cavern by a vertical water shaft that maintains approximately constant pressure in the underground compressed-air reservoir. The schedule/cost for the surface reservoir is not included as it is assumed to be existing on site. The representative CAES plant consists of two units at 110 MW each.

Geothermal

Another demonstrated technology, Geothermal, is not a viable option. No sites with the required characteristics are available within the Duke service area.

7.3.3 Emerging Technologies

This classification is applied to those technologies that show promise but are still in the development stage or have not been used in the utility industry. There is no large, well developed infrastructure to support the technology, nor is it sufficiently developed to instill confidence in utility executives or investors. These technologies include:

Advanced Pulverized Coal (APC) with Chiyoda FGD

The APC power plant represents an evolutionary extension of current technology to higher levels of thermal efficiency. The boiler and turbine are designed for sliding pressure operation with maximum steam conditions of 4500 psi pressure, initial temperature of 1100 degrees Fahrenheit and two reheats to 1050 degrees Fahrenheit. The advanced limestone based flue gas desulfurization (FGD) system produces gypsum. The plant is a single unit facility of 800 MW.

APC with Spray Dryer

Boiler characteristics for the APC with spray dryer are the same as the APC with Chiyoda FGD. The spray dry system uses limestone injection followed by fabric-filter dust collection. The spray dry system is currently applicable only to low-sulfur (<1 percent) coals. The representative APC plant consists of one unit at 800 MW.

Pressurized Fluidized Bed Combustion (PFBC)

Crushed coal is burned with dolomite in a pressurized fluid bed suspended by air blown in from below. The pressure in the combustion chamber is at a level of six to sixteen times atmospheric pressure. Calcium in the dolomite captures most of the sulfur released from the coal during combustion. The hot pressurized gases leaving the combustor pass through a filter to remove suspended particulates and then drive a gas turbine/electric generator. Steam generated in tubes in the bed and in a waste heat boiler drives a conventional steam turbine/electric generator. The PFBC plant consists of one-400 MW unit.

Gasifier/Gas-Fired Boiler

Pulverized coal is gasified by partial oxidation with air in a two-stage entrained system operated at atmospheric pressure. The low BTU gas (CA 1000 BTU/SCF) is processed to remove particulates and sulfur compounds and fired directly in a steam boiler. The heat recovery system in the gasification section is integrated with the steam boiler to maximize the system efficiency. The plant is a single unit facility of 1200 MW.

High Temperature Gas-Cooled Nuclear (HTGR)

HTGR is a nuclear reactor concept that uses helium gas as the heat transfer medium instead of water. The design of the facility is such that passive processes provide for cooling in the event a loss of helium is experienced. HTGR modules are shop fabricated and constructed in a phase-in approach. The representative HTGR plant consists of eight units at 135 MW each. Schedule for these units is based on completion of pairs of units prior to construction of subsequent pairs.

Passive Advanced Light Water Reactor (ALWR)

The passive ALWR design is intended to be a simplified plant in terms of the number of systems and equipment, operations, inspections, and maintenance requirements. Additional improvements over the conventional nuclear technology include a high degree of public safety and licensing confidence, reduced cost, and a short construction schedule. The ALWR plant consist of one unit at 600 MW.

Solar Central Receiver (Hybird)

In the central receiver concept, solar energy is optically focused by a large array of two-axis tracking mirrors (heliostats) onto a central receiver or heat exchanger that is located on top of a central tower. In the hybrid concept, the receiver is a heat exchanger that performs the function of the combustor in a gas turbine/generator power cycle. A parallel combustor that fires low sulfur distillate oil operates when solar energy is not available. The evaluated design for the solar central receiver concept consists of one 200 MW unit.

Solar Photovoltaic Collector

Photovoltaic systems convert sunlight into DC electricity, which is fed to a power conditioning unit for conversion to AC. The technology uses a tracking mechanism to follow the path of the sun to achieve the highest electricity production possible. The representative solar photovoltaic collector plant consists of six units at 5 MW each.

Advanced Batteries

Off-peak electric power is used to charge an improved lead acid battery or an advanced battery based on either the sodium-sulfur or the zinc-chlorine system. The battery system is composed of modular units, each with a three hour storage capacity. Battery capital costs are based on a production rate of ten-20 MW units per year for lead acid and twenty-five-20 MW units per year for the advanced battery. The advanced power converter costs are based on a production of 2000 MW per year. The battery facility evaluated here utilizes a 20 MW unit.

Underground Pumped Storage Hydroelectric

Underground pumped hydro is similar to conventional hydro except the powerhouse and the lower reservoirs are located underground. The configuration is based on six 200-MW units arranged in three pairs of 400 MW each. Each unit pair represents a two step arrangement with an intermediate and a lower power-house. Limitations on the total head (elevation) for commercially available, reversible pump-turbines prevent a single 5000 ft. drop with a single underground reservoir. The reservoirs are sized for 10 hours of storage.

Exhibits 7-2 through 7-11 present screening curves produced for all options not previously eliminated as not being viable on the Duke System.

Exhibit 7-2: Screening Curves

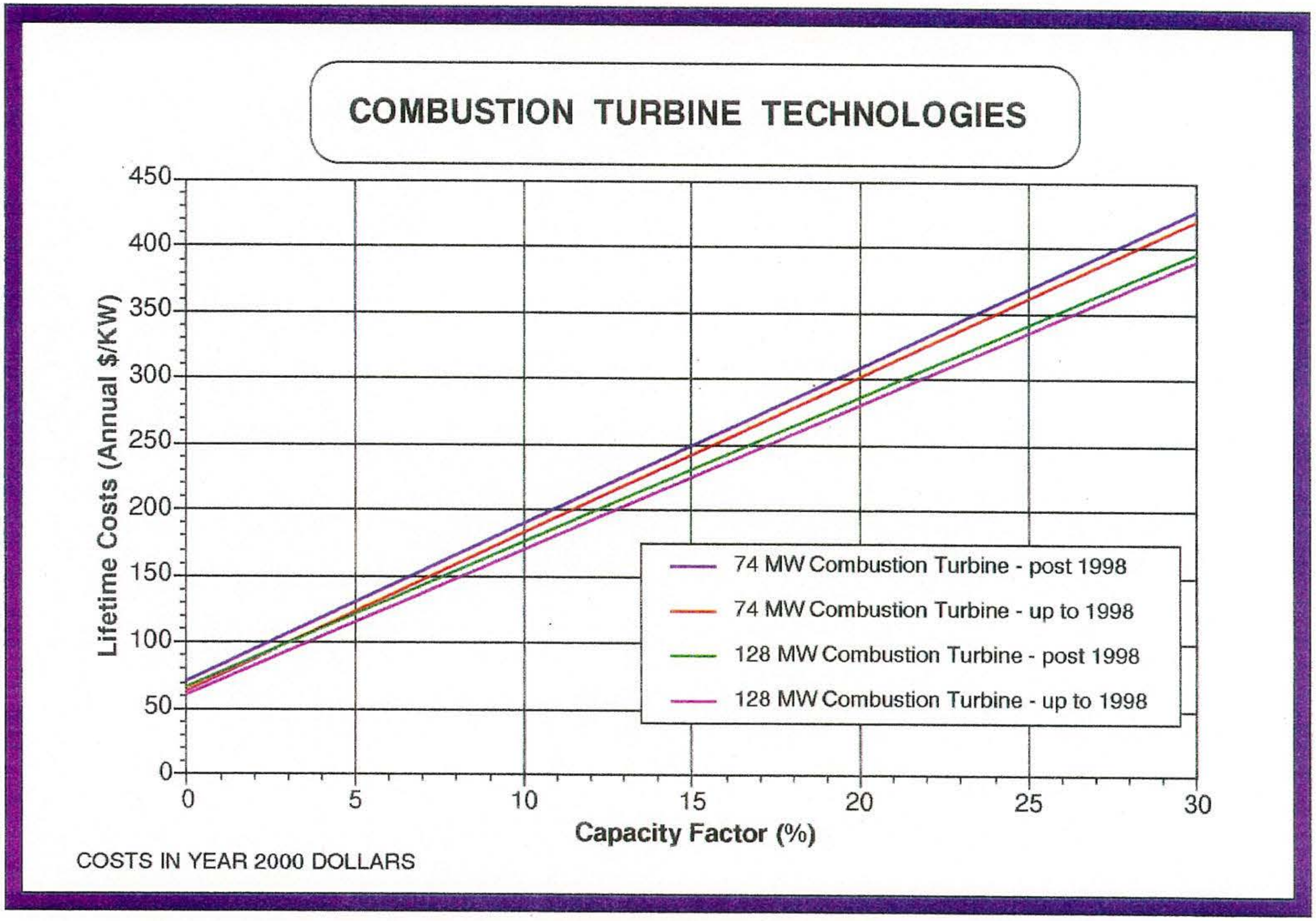


Exhibit 7-3: Screening Curves

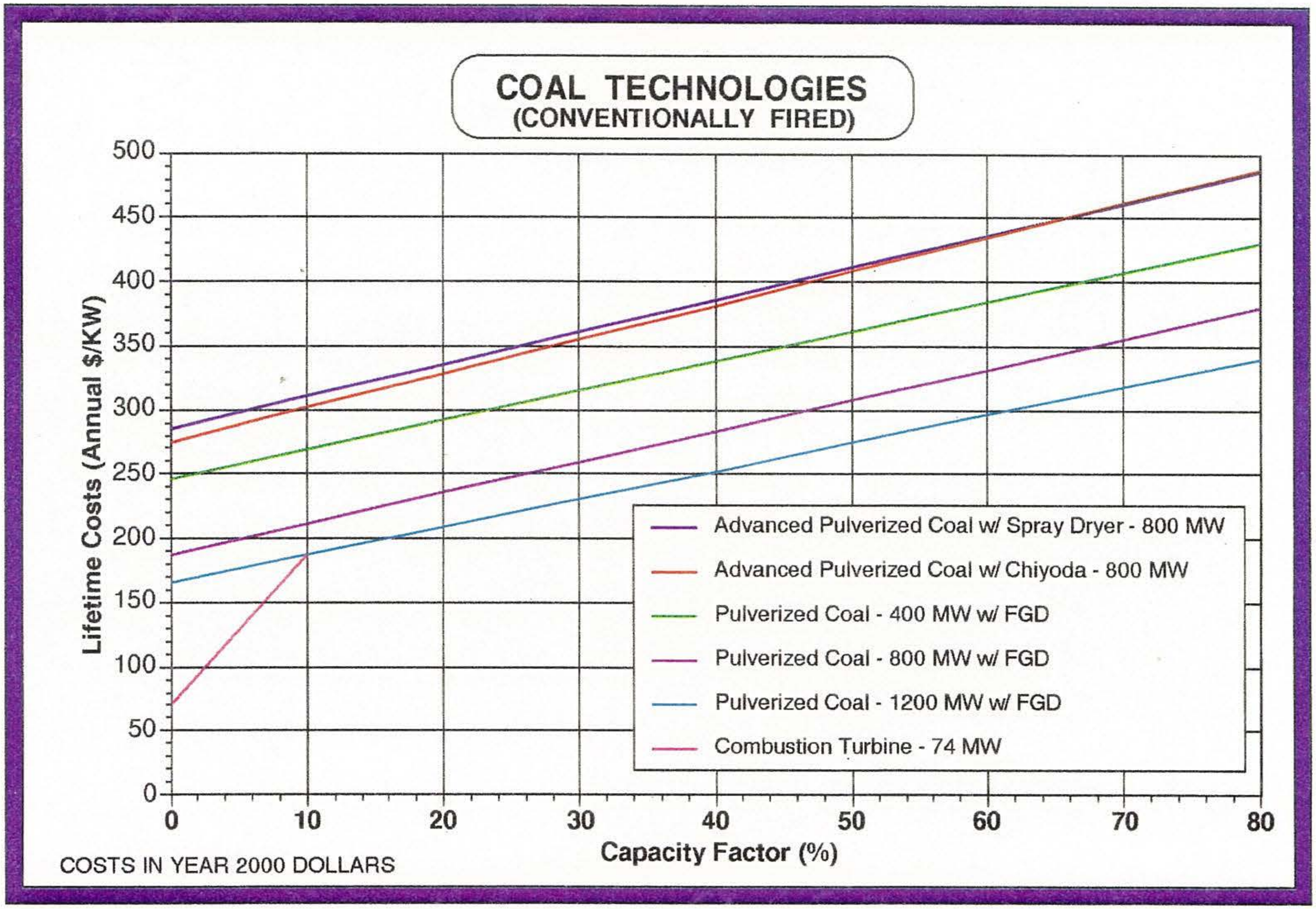


Exhibit 7-4: Screening Curves

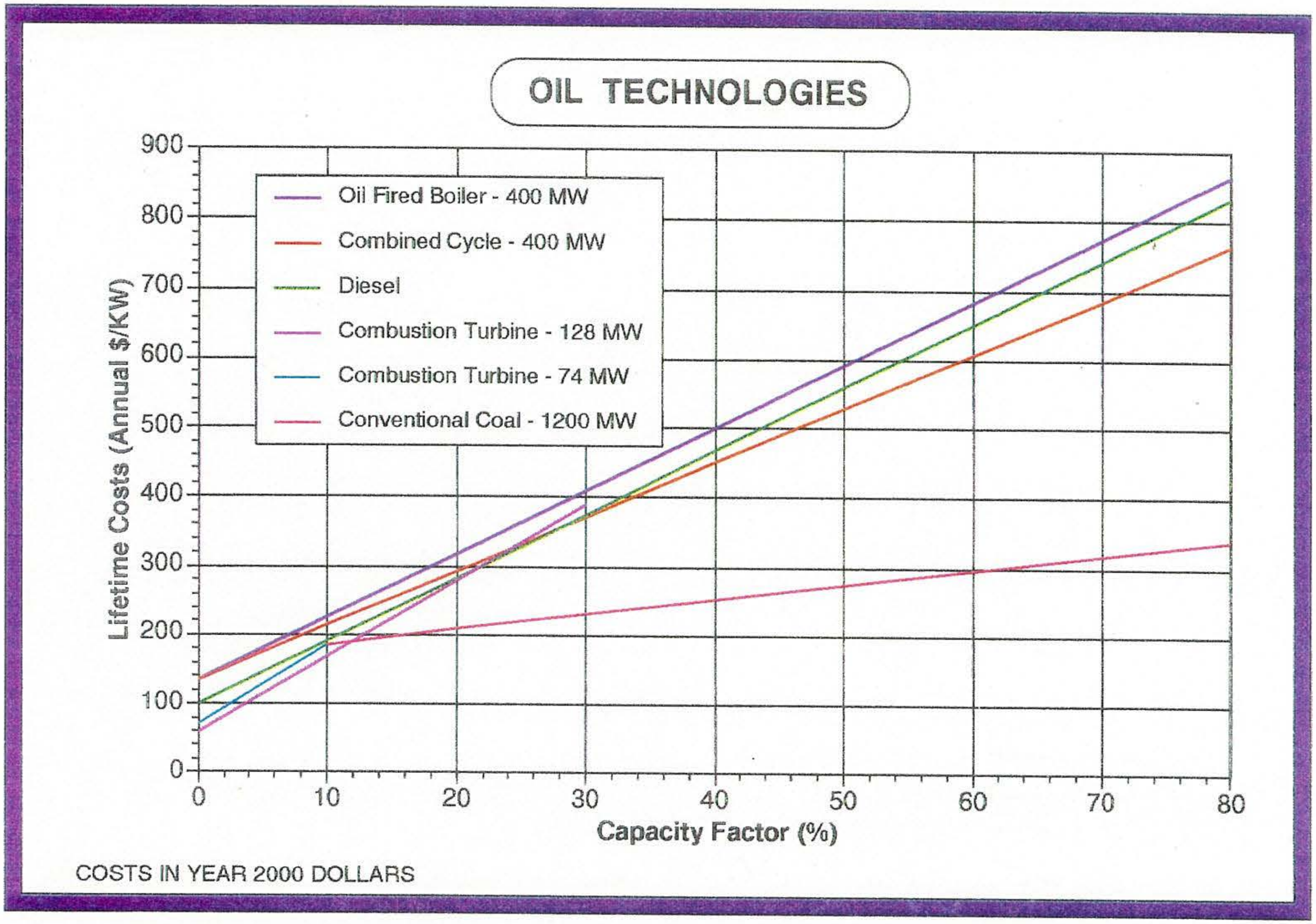


Exhibit 7-5 Screening Curves

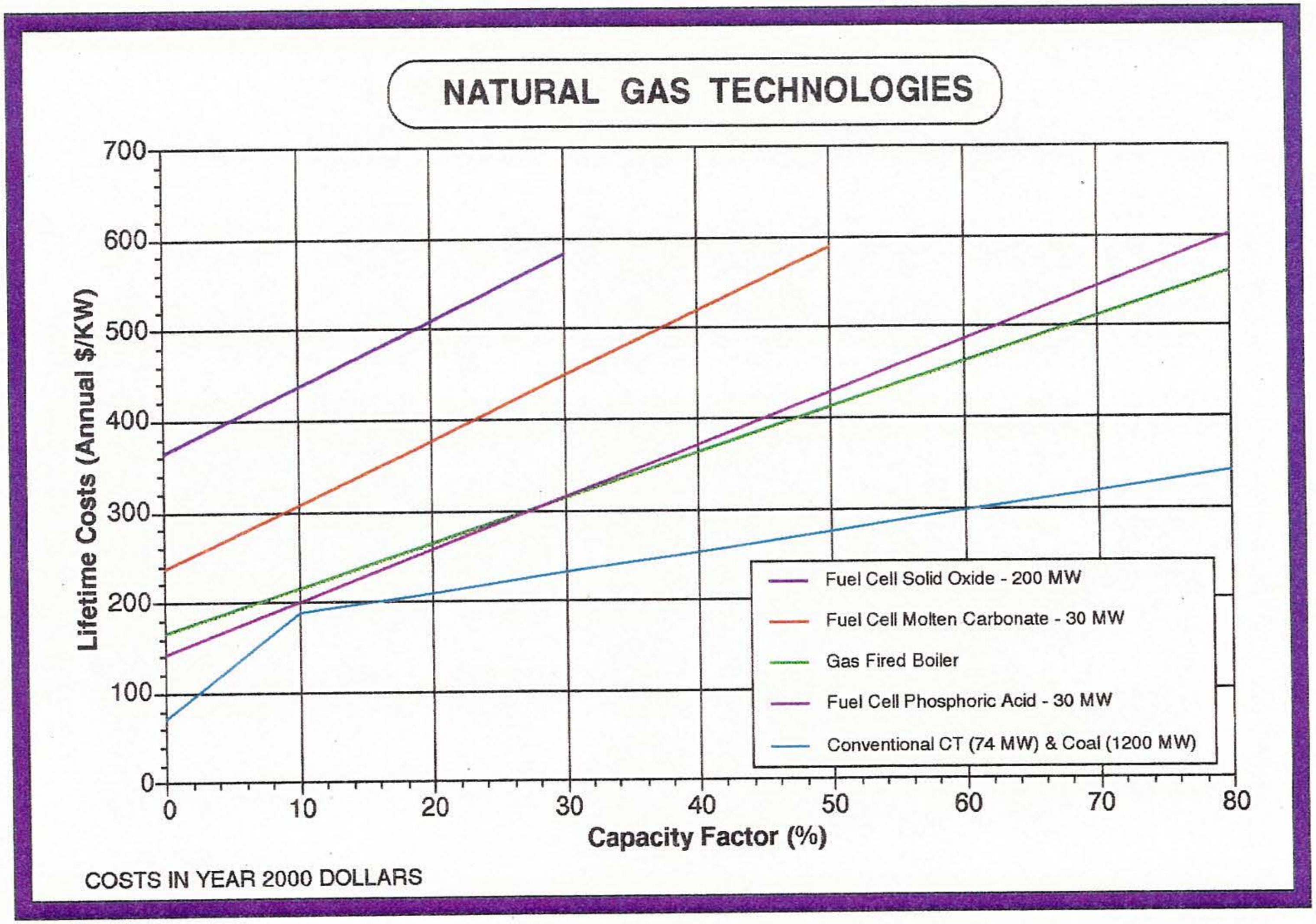


Exhibit 7-6: Screening Curves

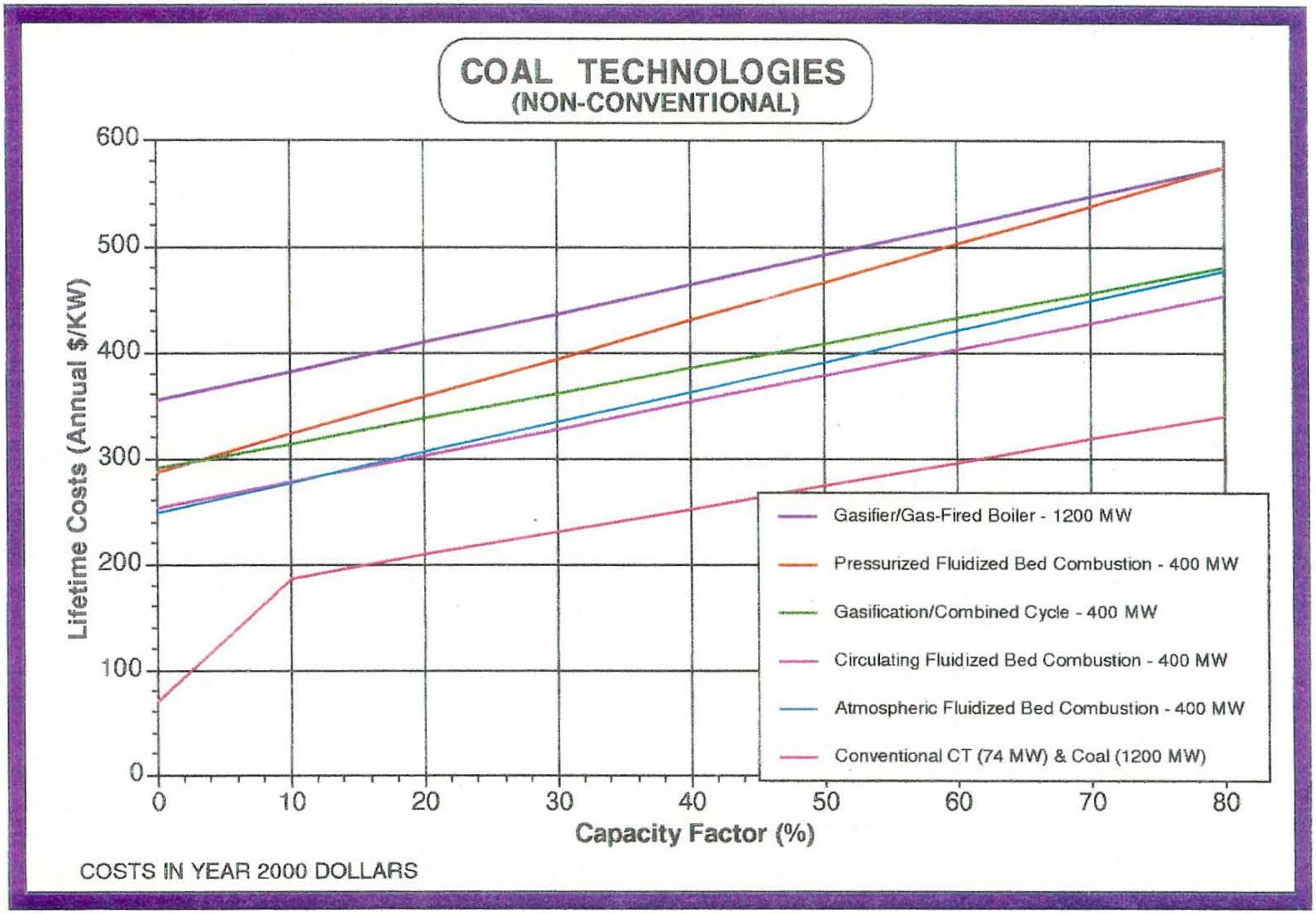


Exhibit 7-7: Screening Curves

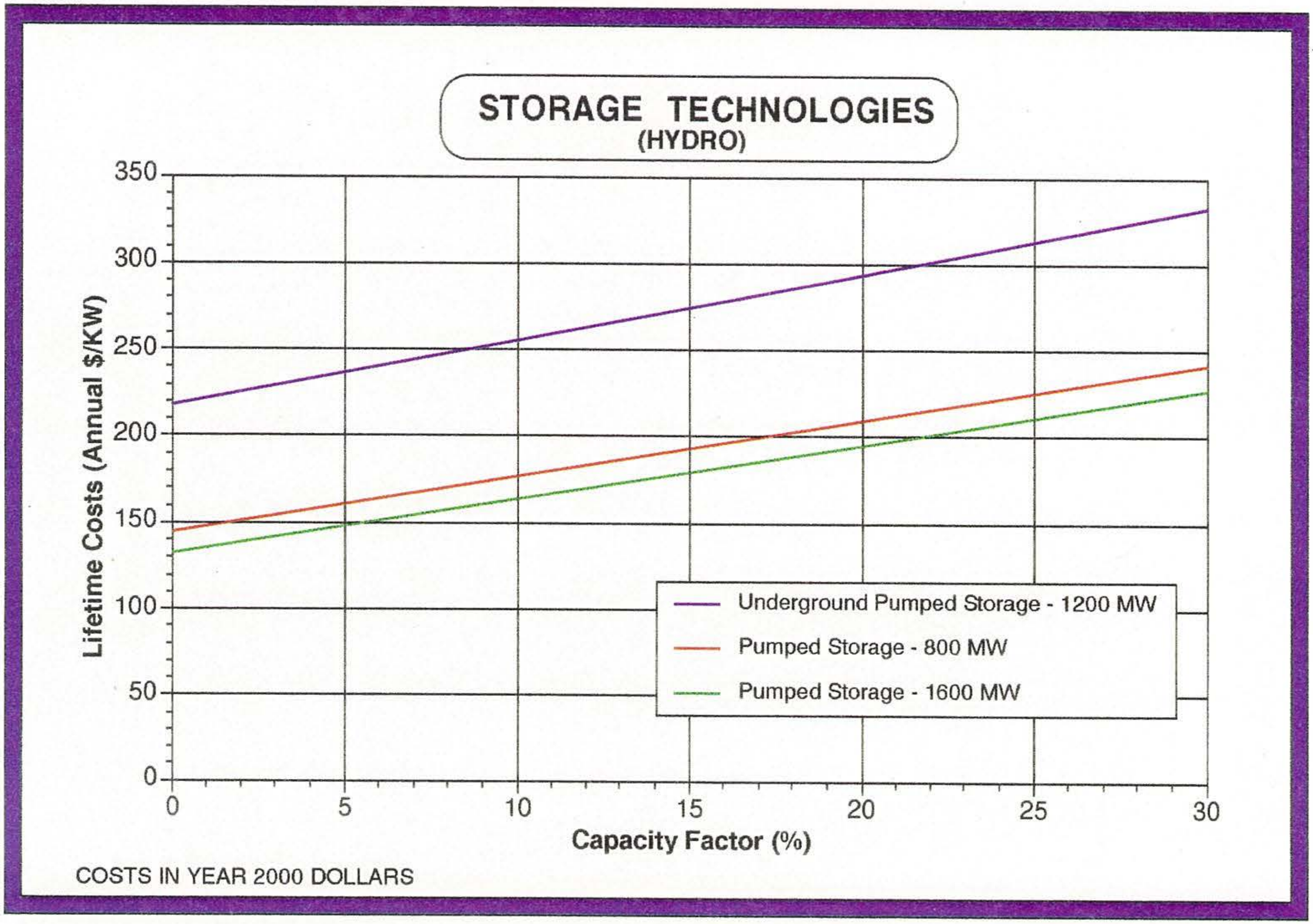


Exhibit 7-8: Screening Curves

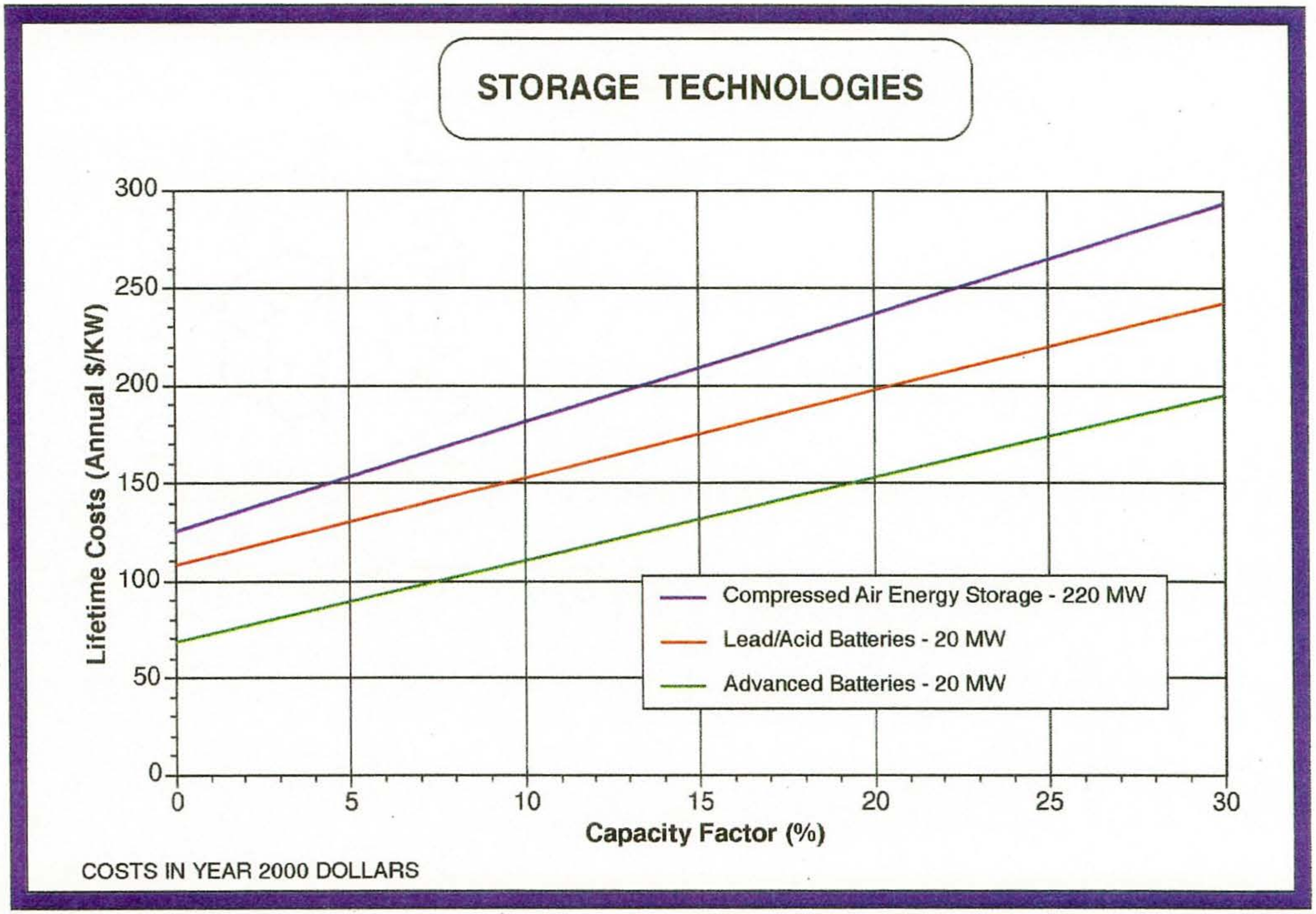


Exhibit 7-9: Screening Curves

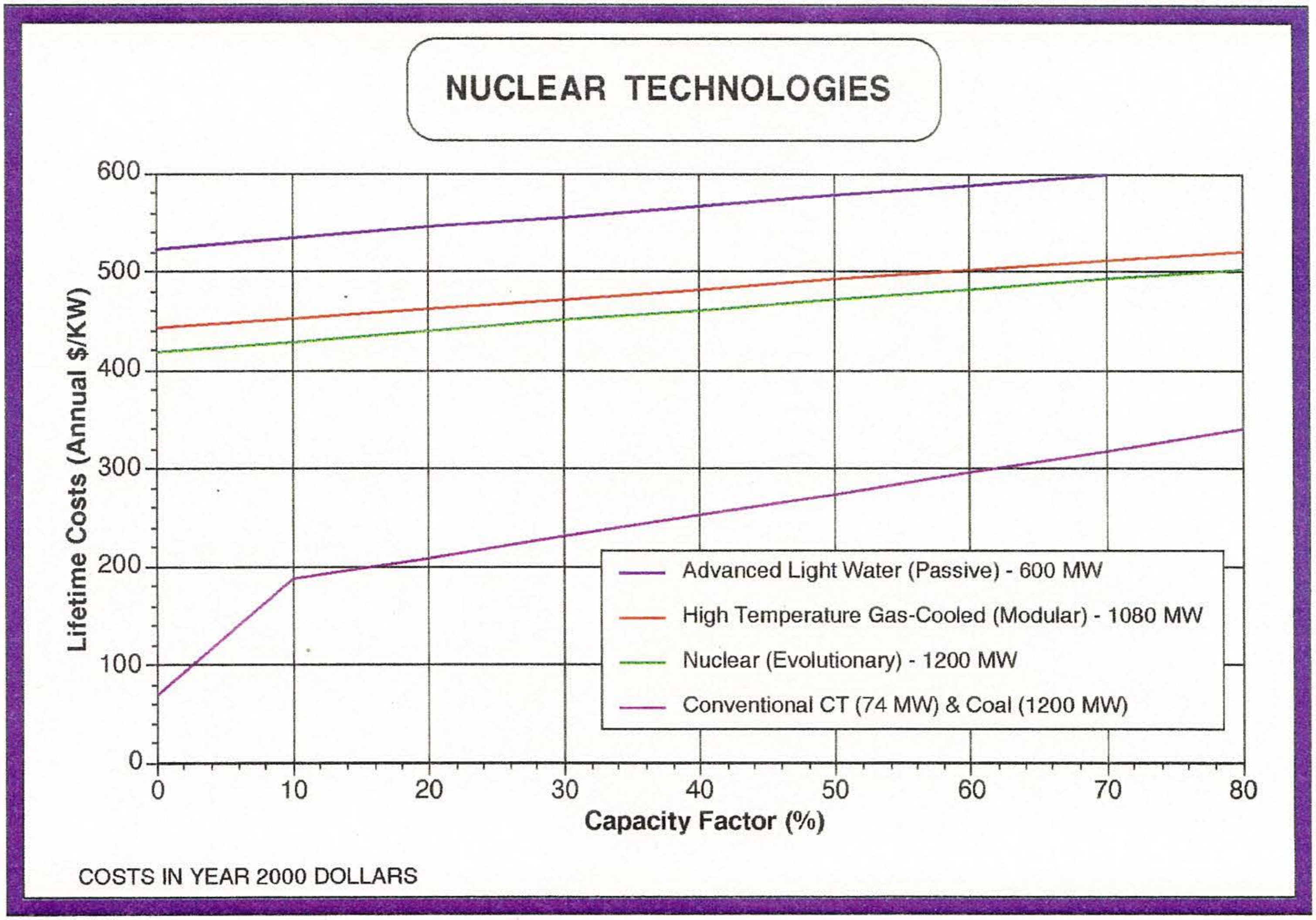


Exhibit 7-10: Screening Curves

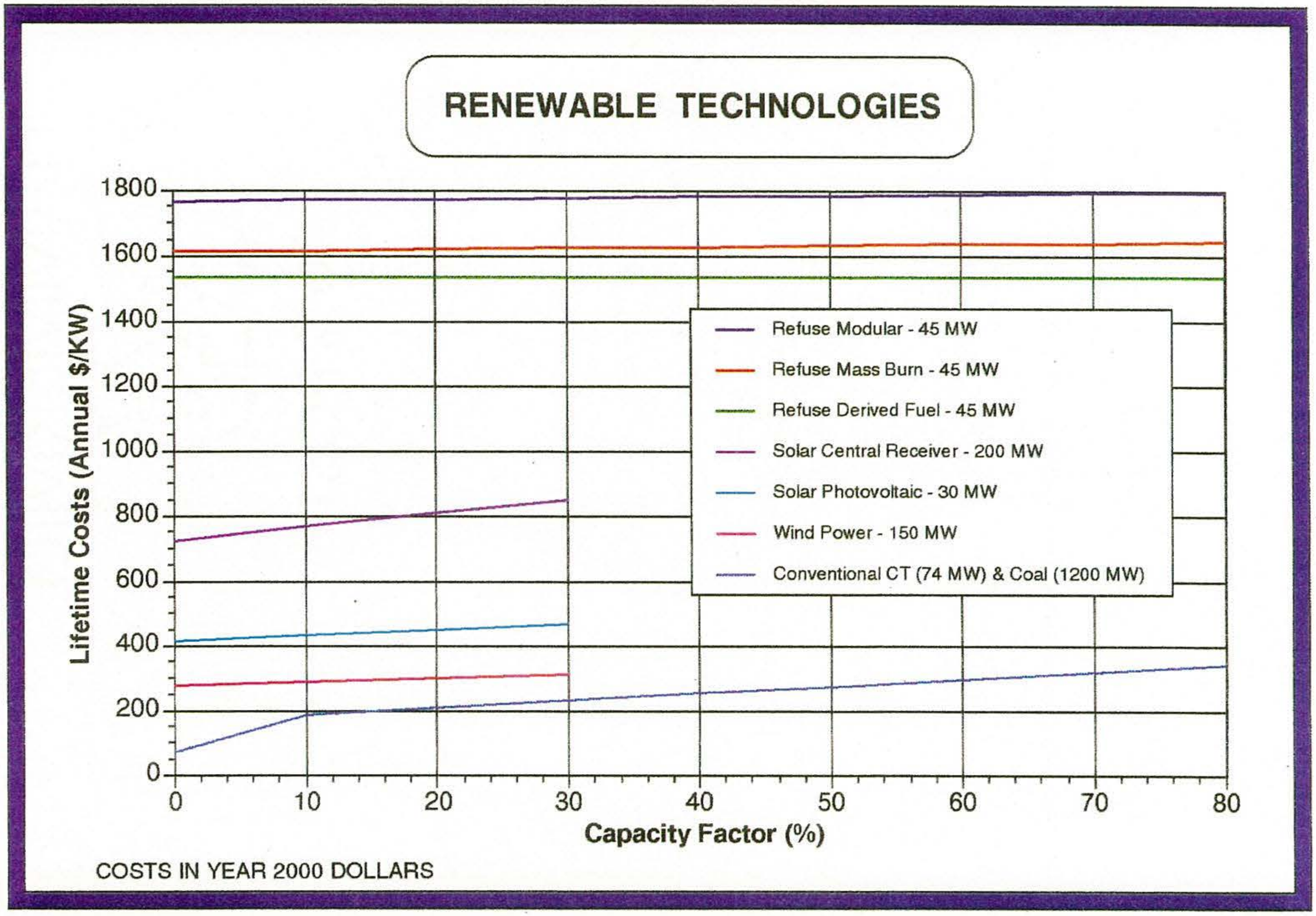
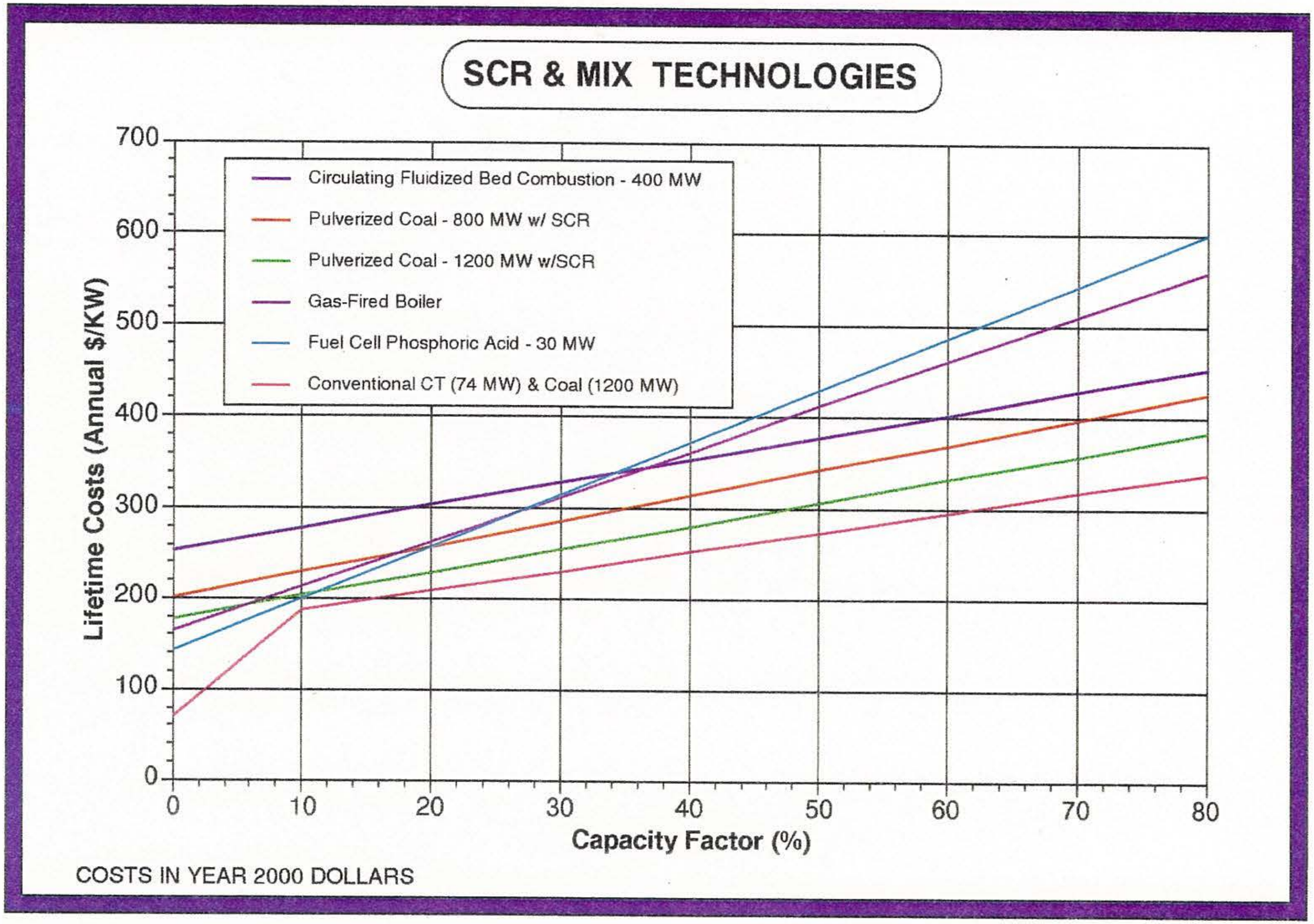


Exhibit 7-11: Screening Curves



7.4 Results

Competetive Low-Cost Alternatives

The technologies selected by the screening analysis process are categorized and listed below. These options were selected as being the low cost or competitive cost alternatives for each category at the anticipated capacity factor.

Exhibit 7-12: SUPPLY-SIDE RESOURCES FORWARDED TO RESOURCE INTEGRATION (9.0)

Gas/Oil Technologies

Combustion Turbine - 74 MW
Combustion Turbine - 128 MW
Combined Cycle - 400 MW
Diesel Generator - 25.6 MW

Coal Technologies (Conventional)

Pulverized Coal - 800 MW with FGD
Pulverized Coal - 1200 MW with FGD

Natural Gas Technologies

Phosporic Acid Fuel Cells - 30 MW

Exhibit 7-13: SUPPLY-SIDE RESOURCES FORWARDED TO RISK ASSESSMENT (10.0)

Coal Technologies (Conventional)

Pulverized Coal - 400 MW with FGD
Pulverized Coal - 1200 MW multi-unit

Storage Technologies

Advanced Batteries - 20 MW
Pumped Storage - 800 MW

Nuclear Technology

Nuclear LWR - 1200 MW

Coal Technologies (Non-Conventional)

Atmospheric Fluidized Bed Combustion (AFBC) - 400 MW
Circulating Fluidized Bed Combustion (CFBC) - 400 MW

Some of these resources were evaluated as supply-side options in Resource Integration (9.0) and others evaluated during Risk Assessment (10.0). Due the large size and large capital expenditures associated with a coal unit and possible dynamic operating benefits of a smaller size unit, Duke performed a study to address coal-unit size and the possibility of a multi-unit addition. Multiple unit pulverized coal sites were not included in the screening curve analysis, but were included in the risk assessment portion of the integration process. For this study, two 600 MW coal units were considered instead of a single 1200 MW unit addition.

Note that Gas/Oil Technologies may be fired by fuel oil or natural gas. Cost evaluations have been performed for fuel oil, which invokes higher emissions controls costs, fuel cost, and maintenance costs. Using these costs eliminates dependence on natural gas fuel to validate screening curve and integration results.

7.5 Emerging Issues

7.5.1 Externalities

In its assessment of resource options, Duke includes the costs to mitigate environmental effects through compliance with applicable environmental laws and regulations and also considers other environmental effects. Numerous state and federal government agencies are responsible for identifying environmental effects, developing regulations, and ensuring compliance. Duke has reviewed a number of methods to include cost estimates for "external" environmental effects over and above those identified by the appropriate regulatory agencies. These methods have not been adopted for this planning process but Duke continues to study various methodologies.

Duke has formed a working group to study methods of evaluating environmental externalities. This working group has:

- Researched a variety of reference documents on the subject of externalities. The articles presented a wide spectrum of theories on the appropriateness of incorporating externality costs. The articles also exhibited a range of scope, treatment, and comprehensiveness for determining externality costs such that a concensus methodology is not yet apparent.
- Contracted a consultant to perform a limited case study in order to understand the potential impact of selected externalities on the Duke system.
- Presented externalities to the Integrated Resource Planning Advisory Panel for their consideration.
- Conducted update/educational presentations for various Duke departments and management groups in order to facilitate an understanding of externalities and solicit further input as to its effects on various aspects of the company's operation.

Duke will continue to include the costs of environmental compliance in its assessment of resource options. Duke also will continue to keep abreast of developments in the area of externalities.

Further, Duke will continue to qualitatively consider environmental effects in its assessment of resource options. In evaluating potential generation technologies, Duke examines the air, water, and solid waste characteristics of the technologies. Duke also considers environmental impacts in the siting of new generation facilities by identifying air and water quality impacts, recreational impacts, and the presence of rare or endangered species for each site.

7.5.2 Emissions and Controls

The effect of Clean Air Act regulations on the existing Duke generating facilities is summarized in Section 4.3.1.

New generation will comply with New Source Performance Standards (NSPS) and requirements of Prevention of Significant Deterioration (PSD). PSD requires that new generation sources install the Best Available Control Technology (BACT). When the NSPS were first implemented the standards were comparable with the BACT. BACT has became increasingly more stringent while NSPS has not, resulting in the requirements of PSD always controlling for major sources. These requirements are not related to Clean Air Act requirements. Controls associated with PSD that Duke is considering in conjunction with possible future generation options are summarized in Exhibits 7-14 and 7-15. The costs associated with these controls have been developed and are incorporated into the supply-side resource costs used in this plan.

7.5.3 Nuclear Re-Emergence

Advances in nuclear design, planning, construction techniques, and licensing are anticipated to result in schedule and cost estimate reductions. These advances may be characterized as:

- Plant Design Standardization
- Pre-Licensed Design Prior to Construction (Design Certification from the NRC)
- 90% Design Completion Prior to Commencing Construction
- Detailed Construction Plans, Schedules, Monitoring Methods and Documentation Techniques Prior to Construction
- Utilization of Advances in Construction Technology (Example: Modularization)

Also, nuclear power's advantage in air emissions over fossil fired alternatives have caused it to receive increased consideration as a viable future baseload generation resource.

Advanced nuclear technology, such as the Light Water Reactor (refer to subsection 7.3) may receive consideration in future IRP's. Such consideration would be based on the state of technology advancements and the potential for innovative partnership arrangements such as cooperative ownership and operation of a regional nuclear facility among several utilities.

Exhibit 7-14: SUPPLY SIDE GENERATION OPTIONS SO2 CONTROL TECHNOLOGY SUMMARY

Supply Side Option	Applicable Environmental Standards		Environmental Compliance Provisions
	NSPS Regulation	BACT INFLUENCE Emission Rate	
Conventional Pulverized	#/MBTU	#/MBTU	
Coal: 400MW Subcritical	.41	.1	95% Wet Scrubber
800MW Subcritical	.41	.1	95% Wet Scrubber
2-Unit 1200MW Subcritical	.41	.1	95% Wet Scrubber
3-Unit 1200MW Subcritical	.41	.1	95% Wet Scrubber
2-Unit 1200MW Supercritical	.41	.1	95% Wet Scrubber
1200MW Supercritical	.41	.1	95% Wet Scrubber
Combustion Turbines			
80MW units, > 1200MW plant	.8	.05	.05% Sulfur Fuel Oil
80MW units, ≤ 1200MW plant	.8	.05	.05% Sulfur Fuel Oil
150MW units, > 1200MW plant	.8	.05	.05% Sulfur Fuel Oil
150MW units, ≤ 1200MW plant	.8	.05	.05% Sulfur Fuel Oil
400MW Combined Cycle	.8	.05	.05% Sulfur Fuel Oil
400MW Oil Fired Boiler	.8	.05	.05% Sulfur Fuel Oil
400MW Gas Fired Boiler	N/A	N/A	N/A
Diesel Generator	.5	.05	.05% Sulfur Fuel Oil

Exhibit 7-15: SUPPLY SIDE GENERATION OPTIONS NOx CONTROL TECHNOLOGY SUMMARY

Supply Side Option	Applicable Environmental Standards: NSPS Regulation		Applicable Environmental Standards: BACT INFLUENCE Emission Rate		Environmental Compliance Provisions
Conventional Pulverized	#/MBTU		#/MBTU		
Coal: 400MW Subcritical	.6		.06		80% removal SCR with Low NOx Burners
800MW Subcritical	.6		.06		80% removal SCR with Low NOx Burners
2-Unit 1200MW Subcritical	.6		.06		80% removal SCR with Low NOx Burners
3-Unit 1200MW Subcritical	.6		.06		80% removal SCR with Low NOx Burners
2-Unit 1200MW Supercritical	.6		.06		80% removal SCR with Low NOx Burners
1200MW Supercritical	.6		.06		80% removal SCR with Low NOx Burners
Combustion Turbines	Oil	Gas	Oil	Gas	
80MW units, > 1200MW plant	.42	.36	.17	.1	Max H_2O Combustor
80MW units, ≤ 1200MW plant	.42	.36	.17	.1	Max H_2O Combustor
150MW units, > 1200MW plant	.42	.36	.17	.1	Max H_2O Combustor
150MW units, ≤ 1200MW plant	.42	.36	.17	.1	Max H_2O Combustor
400MW Combined Cycle	.42	.36	.07	.04	60% removal SCR with max. H_2O combustor
400MW Oil Fired Boiler	.3		.18		80% removal SCR with low NOx burner
400MW Gas Fired Boiler	.2		.04		80% removal SCR with low NOx burner
16 - 1.6 MW Diesel Generators	-		-		After Burners

8.0 PURCHASED RESOURCES

8.1 Introduction

The economic purchase of capacity and energy from Non-Utility Generators (NUGs) and from other electric utilities is important in the integrated planning process. It allows alternatives for customer energy requirements. The region also benefits through purchases that result in the effective and economic use of: surplus capacity and energy from another electric utility; the efficient utilization of waste steam from a cogeneration project, or the use of renewable resources or waste for fuels used in generating electricity.

Purchased Resource options are evaluated to determine the total net benefit of the purchase to Duke's customers, taking into consideration costs, benefits, uncertainties and reliability. Purchased Resource options may be available from cogenerators and small power producers classified as Qualifying Facilities (QFs) under the Public Utility Regulatory Policies Act (PURPA), from Independent Power Producers (IPPs), which are not QFs under PURPA, and from other utilities.

PURPA currently requires that utilities purchase the electric output of QFs at rates that reflect the utility's avoided cost. Avoided cost is defined by PURPA as the incremental cost of electric energy or capacity or both which, but for the purchase from the qualifying facility or facilities, such utility would generate itself or purchase from another source.

The North Carolina Utilities Commission and Public Service Commission of South Carolina have established standard rates, contract terms and procedures for purchases from QFs smaller than 80 MW. Individually, these QFs are not expected to have a significant impact on the IRP. Once contracts based on Commission-approved standard rates and contract terms have been executed with these smaller QFs and their firm capacity is determined and/or demonstrated, the capacity of these QFs is included in the integrated planning process as Firm Purchased Capacity.

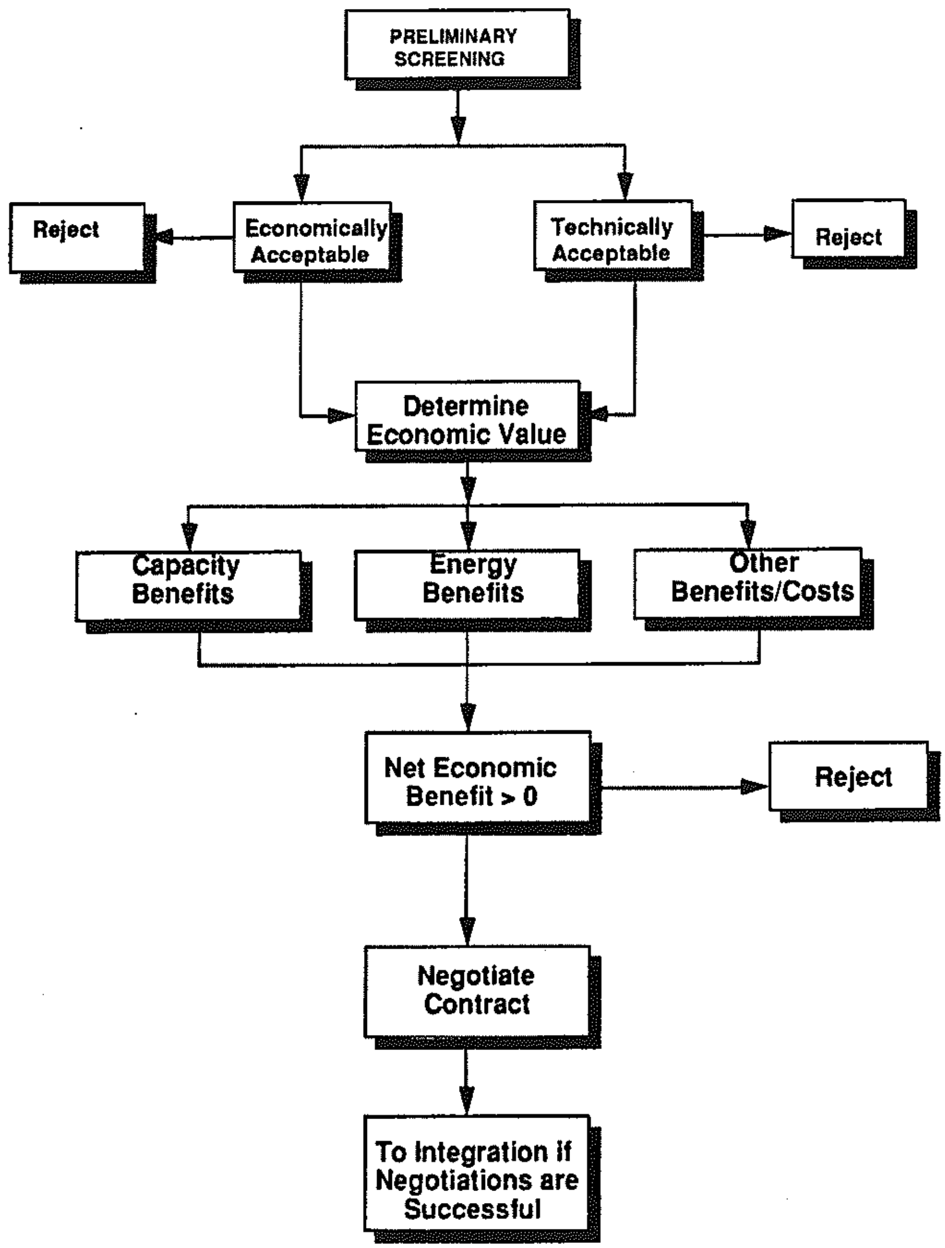
Purchased Resource proposals from QFs larger than 80 MW or from IPPs or from other utilities are evaluated on a case by case basis to determine the total net benefit of the proposal to Duke's customers.

The MW available to Duke from Purchased Resources is sumarized in Section 4.3.2.

8.2 Purchased Resource Process Overview

An illustration of the evaluation process utilized by Duke for Purchased Resource proposals from other utilities, from QFs larger than 80 MW or from IPPs is shown below as Exhibit 8-1.

Exhibit 8-1: PURCHASED RESOURCE ECONOMIC EVALUATION PROCESS DIAGRAM



A preliminary screening evaluation is made to determine the technical and economic viability of the proposal by comparing the proposal with the current IRP. Factors considered in the preliminary screening evaluation of the Purchased Resource proposal include:

- The maturity of the proposal (e.g., existing facility or capacity versus proposed construction)
- The experience of the entity making the proposal
- The financial resources of the entity making the proposal to meet its contractual obligations
- The technology of the proposed generation resource
- The regulatory and licensing requirements facing the proposal including: air and water permits; FERC licenses or approvals; and certification of public convenience and necessity by the Commissions.
- The expected reliability of similar resources controlled by the entity making the proposal

Purchased resource options are further evaluated by determining their economic value. A positive economic benefit for a purchase option results if the present worth of revenue requirements for a plan which includes the purchase is less than for a plan without the purchase.

Capacity benefits, energy benefits and other benefits and costs, such as transmission upgrades and wheeling fees, are examined to determine the net economic benefit of the purchase. The difference between the fixed costs of the purchase option and the value to defer the supply-side option the purchase option would replace gives the net capacity benefit of the purchase. The energy benefit is determined using a detailed production cost simulation model or, in some cases, by direct comparison of energy costs of the purchase option versus the selected supply-side option when similar generation technologies are proposed. When the production cost simulation model is used, the total system production cost is compared between the base plan and the adjusted plan that replaces an equivalent supply-side option with the purchase option that is being evaluated. The difference in system energy costs between the two plans gives the energy benefit of the purchase. Other costs (such as transmission upgrades or wheeling fees) and benefits due to the purchase are then combined with the capacity and energy benefits to give the net economic benefit of the purchase.

Purchased Resources which appear to be economically attractive and technically viable based on the preliminary screening evaluation and the economic evaluation are pursued further through negotiations between Duke and the entity making the proposal. Once a contractual agreement is reached between the parties, the purchased resource is included in the integrated planning process.

Duke will continue to refine its Purchased Resource evaluation process to reduce the cost and time spent in evaluating proposals.

8.3 Non-Utility Generation

Duke will continue to examine proposals made by other entities to construct generating facilities on the Duke system and supply electricity to Duke from those facilities (non-utility generation). Non-utility generation includes cogeneration and small power production facilities which are qualifying facilities (QF) under PURPA and independent power producers (IPP). Non-utility generation proposals that are viable, cost-effective, and in the best interest of Duke's customers will be pursued. During late 1990 and early 1991, Duke evaluated a proposal from an independent power producer for 300 MW of peaking capacity to be available beginning in 1994. Based on its evaluation, Duke determined that the proposal was not a viable, lesser cost alternative to the Lincoln Combustion Turbine Station and therefore should not be included in the 1992 IRP.

As of January 1992, there were 29 cogeneration and small power production facilities on the Duke system operated by customers to offset power requirements they would normally purchase from Duke. The existence of these facilities is recognized in load forecasts. Five of these facilities also sell excess generation to Duke when available. There are also 28 facilities which sell their total generator output to Duke.

The total firm capacity of facilities selling excess or total generator output to Duke incorporated in the current plan is approximately 48 MW. This capacity has recently been updated to reflect new contracts with QFs and updated historical experience with existing QF contracts. The revised firm capacity from NUGs, as of January 1992, is 55 MW. This revised capacity, which is updated annually, will have no material effect on this IRP and will be incorporated in future planning processes.

8.4 Inter-Utility Contracts and Negotiations

Duke keeps abreast of inter-utility purchased power opportunities through periodic contacts with other utilities, selective solicitations for quotes for power and evaluation of request for proposals from other utilities. Inter-utility purchased power opportunities are evaluated by comparison with alternatives with regard to cost, availability and reliability. The amount of capacity available for long term purchase in the southeast has decreased since 1988. The cost of capacity still available for purchase in the southeast is not currently competitive with supply-side options.

Duke is currently purchasing 200 MW from Nantahala Power and Light which Nantahala has purchased from Tennessee Valley Authority. This purchase will continue through 1994.

Duke is in various stages of negotiation with the co-owners of the Catawba Nuclear Station regarding the terms and conditions for the possible transfer and replacement of a portion of the co-owner's Catawba project capacity and energy off the Duke system. The timeframe of any such transfer(s), if ultimately agreed upon by all parties, is not currently known but would not commence until the mid 1990s.

Duke is negotiating new interconnection agreements and other power contracts with neighboring utilities with whom Duke has no current agreements. These new agreements will offer more opportunities for Duke to purchase and sell on a short term basis. Duke has filed with FERC for approval of two contracts with Cajun Electric Power Cooperative: one contract for the purchase or sale of economy energy, the other contract for the purchase or sale of short term power.

Duke is revising existing agreements with other utilities. The revised agreements will include enhancements such as formula-based rates ceiling-capacity charges and contract modifications which will allow purchases as well as sales of power. The revised agreements provide more flexibility in day-to-day operations with our utility neighbors.

8.5 Competitive Procurement of Purchased Resources

Duke is currently developing a competitive bidding process and a request for proposals which can be utilized for future capacity needs. It is anticipated that the competitive procurement process would include a solicitation and evaluation of capacity offered by QFs, IPPs, and other utilities. A draft of the competitive procurement process and request for proposals package is expected to be completed in December 1992.

The timing of future capacity needs identified in the current planning process is such that the release of a request for proposal or other form of competitive solicitation and evaluation is not required in the time frame covered by the Short-term Action Plan. Duke will continue with its development and analysis of the competitive procurement process and request for proposal for implementation at the appropriate time.

9.0 RESOURCE INTEGRATION

9.1 Introduction

The objective of Resource Integration is to create alternative plans(s). The alternative plans will provide a combination of available resources (demand-side, supply-side, purchased power, etc...) that will dependably and reliably meet the customer's needs. Resource Integration does not consider risks or uncertainties.

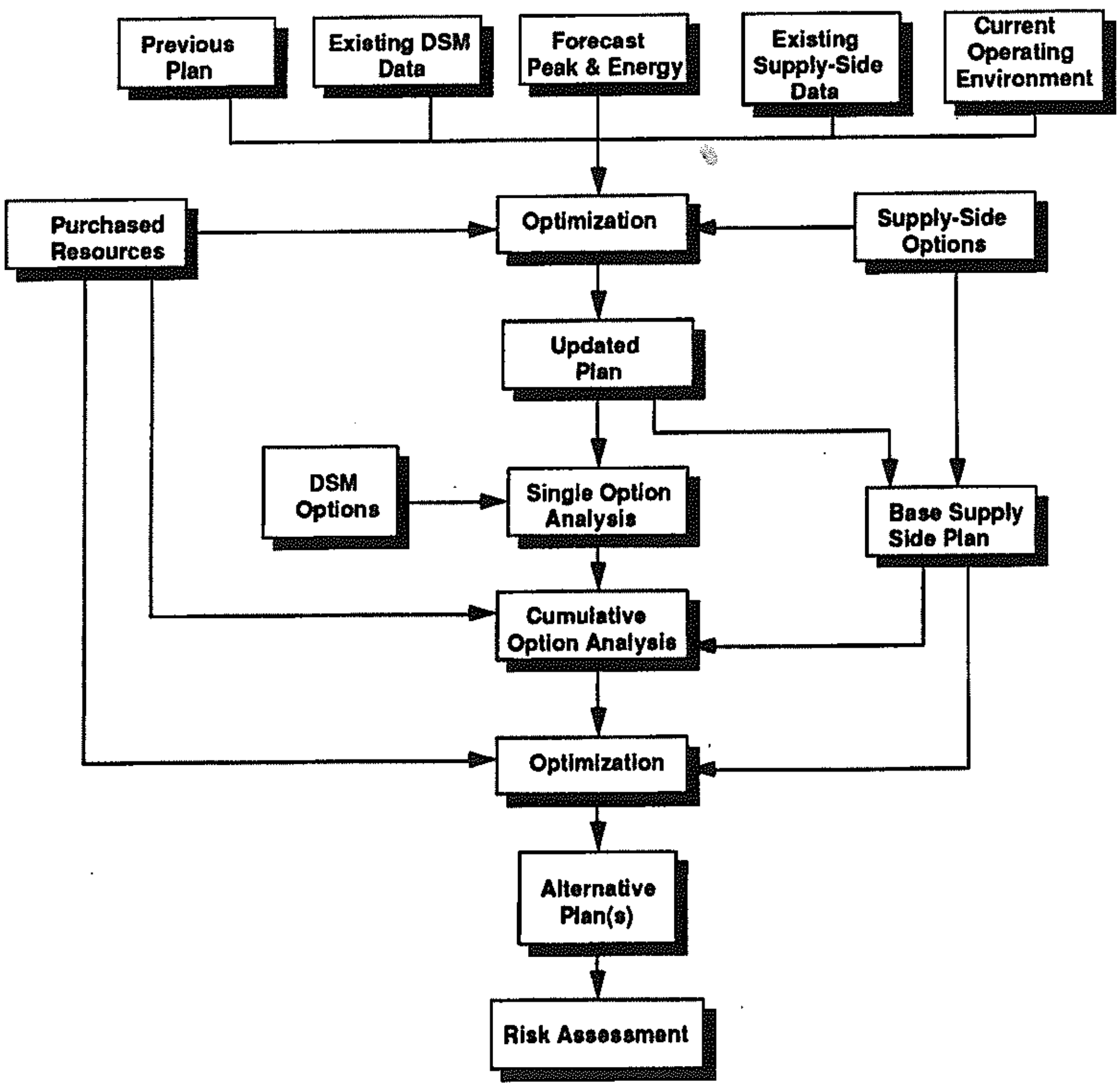
Resource Integration or the Integration Process uses various methods and several production costing and optimization planning models to determine the alternative plans. The integration process has, over the years, been very dynamic. Changes have occurred in the process and with the methods used to accomplish the various tasks. The objective of such a dynamic process is to improve the overall process and shorten the time required to produce the results. The integration process uses utility industry accepted models for detailed production cost simulation and present worth economics to form the alternative plans. The process and models used are discussed in more detail under Section 9.2 and 9.3.

Resource Integration uses the results presented in the Current Operating Environment, Forecast, Demand-Side Resources, Supply-Side Resources and Purchase Resources sections. The results of the integration process will provide the inputs to Risk Assessment.

9.2 Process Overview

The integration process, shown in Exhibit 9-1, starts with the development of an Updated Plan and continues with the determination of a Base Supply-Side Plan, Purchased Resources, Single Option Analysis and Cumulative Option Analysis. The final step involves an optimization of the DSM options from Cumulative Option Analysis with the supply-side options from the Base Supply-Side Plan and any additional purchased resources. This optimization results in one or more alternative plans.

Exhibit 9-1: RESOURCE INTEGRATION PROCESS DIAGRAM



Updated Plan

The fundamental assumptions in the previous plan are modified to reflect current conditions. Examples of updated data included the forecast, supply-side options data, existing DSM program data, economic parameters, purchased power data and operating cost data.

These current conditions are used in conjunction with the Previous Plan and an optimization model (PROVIEW) to create an Updated Plan. The Updated Plan is then used as a starting point to develop the Base Supply-Side Plan and to perform Single Option Analysis.

Base Supply-Side Plan

To eliminate the supply-side resources whose comparative costs are high, the supply-side alternatives are analyzed using screening curves. This process and the results are described in Supply-Side Resources (7.0). The resulting comparatively cost-effective supply-side options are input into an optimization planning model (PROVIEW) to determine an optimal Base Supply-Side Plan. For the initial supply-side analysis, the existing DSM programs are included in the analysis. The model is used with a criterion of minimizing the present worth of revenue requirements (PWRR). Appendix IX-1 describes each of the models in more detail.

Purchased Resources

Purchased resources analysis is an on-going process and is dependent on their availability over time. The purchased resource agreements can modify the supply-side or DSM options chosen. An optimization or production costing model is used to determine the possible benefits of the purchase resource.

Single Option Analysis

Just as supply-side resources are screened, an initial analysis of DSM options is performed. The details of this analysis are described in Demand-Side Resources (6.0). The results from the DSM analyses are then passed to Resource Integration. The DSM option integration begins with the economic evaluation of each DSM option in Single Option Analysis. Single Option Analysis evaluates each of the DSM options one at a time against the Updated Plan and determines the overall benefit of each option. PROVIEW is used to establish the overall benefit by determining the production and capacity impacts. These impacts along with the financial data associated with each DSM option allows the computation of an average cost of energy. This average cost of energy is then used to rank the options.

Some of the DSM options evaluated during Single Option Analysis have several cases which are mutually exclusive. Only one of these cases can continue in the integration analyses. The case selected is determined by economic analyses and sound engineering judgement. Sound engineering judgement accounts for factors such as customer acceptance, perceived benefits and opportunities.

Cumulative Option Analysis

Next the DSM option's single option ranking is used to determine the economic benefits and costs in a cumulative manner. This step is Cumulative Option Analysis.

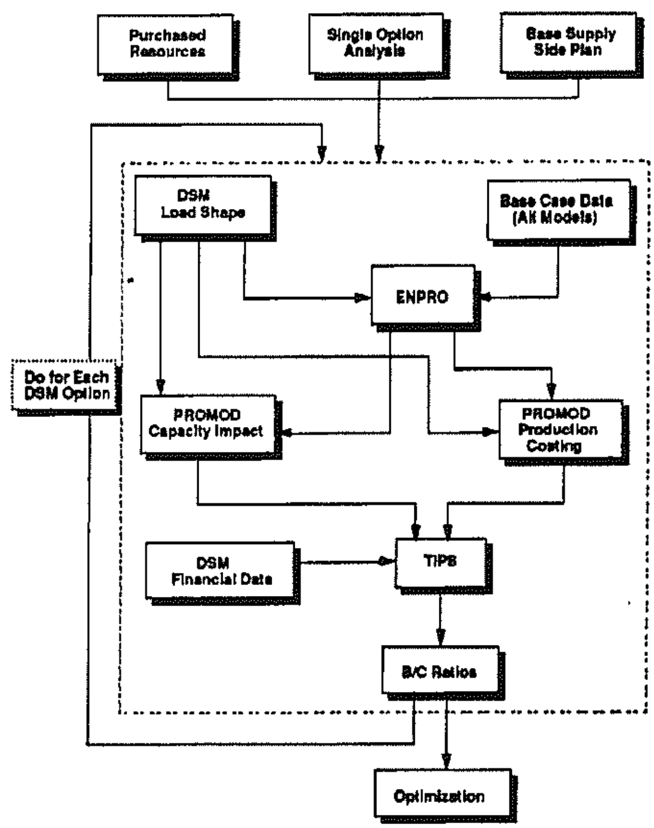
Cumulative Option Analysis uses the Single Option Analysis result to reevaluate the DSM options in ranked order. This method recognizes the synergism which occurs among options and with the existing system.

To determine a more accurate starting point, any assumptions that have changed since the development of the Updated Plan need to be included. These assumptions would include the results from the Base Supply-Side Plan or Purchased Resources analyses. Base Supply-Side Plan changes usually deal with commercial operation dates of baseload additions or a change in technology.

In cumulative analysis several planning models are used to determine each DSM option's benefits and costs by determining the production and capacity impacts. These impacts along with financial data associated with each option result in the computation of a Benefit/Cost (B/C) ratio. This B/C ratio is provided for several economic tests: 1) Participant Test (PART); 2) Total Resource Cost Test (TRC); 3) Rate Impact Measure Test (RIM); and 4) Utility Cost Test (UC). Appendix IX-2 describes each of the economic tests in detail.

The Cumulative Option Analysis is performed using several planning models as shown in Exhibit 9-2. A chronological production costing model (ENPRO), a probabilistic production costing model (PROMOD) and a Duke developed economic spreadsheet (TIPS).

Exhibit 9-2: CUMULATIVE OPTION ANALYSIS PROCESS DIAGRAM



ENPRO is used to include the effects of DSM interruptible options with payback constraints. PROMOD has two purposes: 1) to determine the production impact; and 2) to determine the capacity impacts. Production impacts are determined by computing the change in production cost of an expansion plan with the DSM option to an expansion plan without the DSM option. Capacity impacts are determined by computing the difference in two expansion plans that have the same reliability. One of the expansion plans will include the DSM option and the other expansion plan will not include the DSM option. This computed difference defines the capacity impact for the DSM option and is the Maximum Net Dependable Capability (MNDC).

Using the PROMOD results for the change in production cost, MNDC capacity of the DSM option, and entering them with the DSM financial data into TIPS, the B/C ratios are computed. Appendix IX-1 includes a description of each model used in the Cumulative Option Analysis.

Optimization

The final step in the integration process is to optimize the Base Supply-Side Plan, Purchased Resources and the Cumulative Option Analysis. Using the B/C ratios from Cumulative Option Analysis, the supply-side options from the Base Supply-Side Plan and purchased agreements from Purchased Resources, alternative plans are developed using PROVIEW. PROVIEW develops the alternative plans by optimizing the expansion plan with a criterion of minimization of present worth of revenue requirements (PWRR).

The resulting alternative plans are then subjected to an analysis to consider the uncertainties and risks in the underlying assumptions. This analysis is Risk Assessment and is discussed in Section 10.

9.3 Integration Details and Available Options

9.3.1 Major Assumptions and Updated Plan Data

To perform Resource Integration, the models used in all analyses required inputs to describe the existing generating unit operating parameters, financial and economic conditions, expected load demand, minimum planning reserve margins and the existing DSM resources. Following is a list of major assumptions that have not been discussed:

Study Period: The official study period for the integration process was Jan. 1, 1992 through Dec. 31, 2006.

Forecast Dates: The basis for all analyses was the May 1991 load forecast for the Duke system and the April 1990 Nantahala Power and Light load forecast.

NP&L: Nantahala Power and Light load and capacity resources were incorporated as of October 1990. The Nantahala total generating capacity was 99 MW.

Reserve Margin: A minimum 20 percent planning reserve margin was used in all expansion analyses.

Low Sulfur Coal: A switch from the low sulfur coal currently used to a lower sulfur coal is planned for all fossil units, except Belews Creek units 1 and 2, beginning in 1999. At Belews Creek units 1 and 2, scrubbers are assumed to be installed in 1998 and 2000 respectively.

Data Snapshot: All data used in the integration process, unless specifically stated otherwise, was a snapshot as of June 1, 1991.

DSM Programs: The existing DSM programs that were included as part of the Updated Plan are listed in Exhibit 9-3. Refer to Demand-Side Options/Programs (6.3) for details of each DSM program.

Exhibit 9-3: EXISTING DSM PROGRAMS

Residential Load Control - Water Heating
Residential Load Control - Air Conditioning
Residential Controlled Off Peak Water Heating
High Efficiency Heat Pump Payment
High Efficiency Central Air Conditioning Payment
Residential Add-On (Dual Fuel) Heat Pump
High Efficiency Freezer Payment
High Efficiency Refrigerator Payment
Residential Insulation - New Residences (2% Discount)
Residential Insulation Loan
Interruptible Service
Standby Generator Without Backfeed

9.3.2 Base Supply-Side Plan

Duke has been evaluating supply-side options for many years. The interactions of non-linear heat rates, outage requirements, fuel alternatives, and the many costs associated with a typical generating unit are extremely complex. However, the analytical techniques associated with these parameters are relatively mature, and have resulted in well documented and highly refined modeling techniques throughout the utility industry.

The evaluation began by collecting specific data for each supply-side option which passed the screening analysis. These options are listed in Exhibit 9-4 and are the results presented in Supply-Side Resource Results (7.4).

Exhibit 9-4: AVAILABLE BASE SUPPLY-SIDE PLAN OPTIONS

Gas/Oil Technologies

Combustion Turbine - 74 MW
Combustion Turbine - 128 MW
Combined Cycle - 400 MW
Diesel - 25.6 MW

Coal Technologies (Conventional)

Pulverized Coal - 800 MW with FGD
Pulverized Coal - 1200 MW with FGD

Natural Gas Technologies

Phosphoric Acid Fuel Cells - 30 MW

To evaluate the available supply-side options, the optimization models require numerous other inputs to describe the existing generating unit operating parameters, financial and economic conditions, expected load demand, minimum planning reserve margin and the existing DSM programs.

This data was entered into the optimization planning model (PROVIEW) which utilizes probabilistic simulation and dynamic programming. PROVIEW examines thousands of possible combinations of new supply-side options and evaluates the interaction of each combination with the existing generating units and existing DSM programs. The cost to produce the energy to meet demand (production cost) and the cost required for the construction (capital cost) of additional resources are calculated for each combination. Since each combination is evaluated under the same expected load conditions, the lowest cost supply-side plan is determined through a dynamic programming algorithm that searches to identify the supply-side options which yield the lowest present worth of revenue requirements.

Of the supply-side options presented in Exhibit 9-4, only the 74 MW and 128 MW combustion turbine and 1200 MW pulverized coal options were chosen by PROVIEW. The 74 MW combustion turbine option was chosen prior to 1999. After 1999, the 128 MW combustion turbine was chosen. Exhibit 9-5 shows the resulting Base Supply-Side Plan and the cumulative MNDC amount of existing DSM programs that were presented in Exhibit 9-3.

Exhibit 9-5: BASE SUPPLY-SIDE PLAN

Year	Supply-Side 74MW CT (MW)	128MW CT (MW)	1200 MW Coal (MW)	Demand-Side Cumulative MNDC (MW)
1992				1099
1993				1113
1994				1144
1995				1194
1996	444			1233
1997	444			1247
1998	222			1367
1999		640		1371
2000		384		1371
2001		512		1374
2002		512		1380
2003			1200	1380
2004				1380
2005		384		1380
2006			1200	1380

Maximum Net Dependable Capability (MNDC) is determined by computing the difference in two expansion plans that have the same reliability. One of the expansion plans includes the DSM options and the other did not include the DSM options.

The Base Supply-Side Plan demonstrates a strong need for peaking generation through the 1990s. Baseload generation becomes desirable after the turn of the century. Duke's clear choice of supply-side options to meet the requirements of the 1990s are combustion turbines. Conventional pulverized coal proved to be the supply-side option to meet the baseload generation needs.

9.3.3 Purchased Power Analysis

Purchased power options are typically generation based, requiring an evaluation similar to supply-side resources. Many purchase options are available for relatively short periods. Therefore, purchased power may defer other alternatives without replacing them entirely.

Possible exceptions to this deferral analysis are qualifying facilities (QFs) which are included under the Public Utility Regulatory Policies Act (PURPA). These purchases are currently mandated by this act and become part of the integrated resource plan once contracts with QFs committing firm capacity are executed.

No new purchased power options were considered in the integration analysis for the current planning process.

9.3.4 Single Option Analysis

Single Option Analysis is a relatively new process as compared to the process used to evaluate supply-side options. The complexity of this process is caused by many of the same factors impacting supply-side analysis. In addition, establishing a system reliability criterion, measuring DSM options against that reliability criterion, modeling operating characteristics and expansion flexibility increase the complexity of the process.

Single Option Analysis evaluates each of the DSM options one at a time and determines the benefit of each option. A list of the DSM options passed to Single Option Analysis was presented in Exhibit 6-7.

Included in the analysis were production cost changes, capacity impacts and financial costs. PROVIEW was used to evaluate the production and capacity components and perform the necessary economic analysis including end-effects to determine an average cost of energy.

To improve on the integration process, Duke contracted with Energy Management Associates(EMA) in late 1990 to properly incorporate, into PROVIEW, the simulation of load control options including the effects and limitations of payback and to correctly represent constraints that effect their use.

In addition to being able to handle the payback characteristic of load control options, PROVIEW must still be able to address reliability and express the value of a DSM option in terms of Maximum Net Dependable Capability (MNDC). PROVIEW performed the probabilistic production costing and reliability equalization.

The Rate Impact Measure (RIM) test was used to rank the DSM options. The parameters used in the RIM test were: production cost; capacity cost; marketing cost; administrative cost; advertising cost; equipment cost; customer credit costs; and revenue impacts. These parameters were computed or entered into PROVIEW to determine an average cost of energy using economic analysis including end-effects. Once an average cost of energy was determined for each of the DSM options, the options were ranked.

Some of the DSM options evaluated during Single Option Analysis have several cases which are mutually exclusive. Only one of these cases can continue in the integration analysis. The case selected is determined by economic analysis and sound engineering judgement. The ranking within each multiple case option was close and did not provide obvious selections. Therefore, engineering judgements on items such as: customer participation; limitation of opportunities; timing of DSM availability; customer's existing equipment size; and benefits over existing rate schedules were the deciding factors. The DSM options in the order they will be evaluated in Cumulative Option Analysis are presented in Exhibit 9-6.

Exhibit 9-6: RANKING FOR CUMULATIVE OPTION ANALYSIS

Interruptible Service - Start the Additions in 2000
Standby Generator With Backfeed - 1500 KW/Customer Exported
High Efficiency Unitary Equipment for Air Conditioning
Residential Load Control - Air Conditioning
High Efficiency Chillers for Air Conditioning
Non-Residential High Efficiency Indoor Lighting - Electric Heating - New Market
Residental Controlled Off Peak Water Heating - WC submetered lower rate
Standby Generator - Category C
Non-Residential High Efficiency Indoor Lighting - Electric Heating - Existing Market
Standby Generator - Capacity Improvement - $10,000 Payment/Customer
Residential HVAC Tune-Up Program
Residential Load Control - Water Heating
Non-Residential High Efficiency Indoor Lighting - OPT Schedule - New Market
Residential Water Heater Insulating Blanket
Non-Residential High Efficiency Indoor Lighting - Fossil Heating - New Market
Non-Residential High Efficiency Indoor Lighting - Fossil Heating - Existing Market
Non-Residential High Efficiency Indoor Lighting - OPT Schedule - Existing Market
Motor Systems - 20% Penetration - $6 per Horsepower

9.3.5 Cumulative Option Analysis

Next the DSM option's single option ranking is used to determine the economic benefits and costs in a cumulative manner. This step is Cumulative Option Analysis. This method recognizes the synergism which occurs among options and with the existing system.

To determine a more accurate starting point, any assumptions that have changed since the development of the Updated Plan need to be included. These assumptions would include the results from the Base Supply-Side Plan or Purchased Resources analyses. Base Supply-Side Plan changes usually deal with commercial operation dates of baseload additions or a change in technology.

In cumulative analysis several planning models are used to determine each DSM option's benefits and costs by determining the production and capacity impacts. These impacts along with financial data associated with each option result in the computation of a Benefit/Cost (B/C) ratio. This B/C ratio is computed for several economic tests: 1) Participant Test (PART); 2) Total Resource Cost Test (TRC); 3) Rate Impact Measure Test (RIM); and 4) Utility Cost Test (UC). Appendix IX-2 describes each of the economic tests in detail.

Cumulative Option Analysis is performed using several planning models. A chronological production costing model (ENPRO), a probabilistic production costing model (PROMOD) and a Duke developed economic spreadsheet (TIPS).

The chronological production costing model (ENPRO) is used to include the effects of DSM interruptible options with payback constraints. The probabilistic production costing model (PROMOD) has two purposes: 1) to determine the production cost impacts; and 2) to determine the capacity impacts. Production cost impacts are determined by computing the difference in production cost of an expansion plan with the DSM option to an expansion plan without the DSM option. Capacity impacts are determined by computing the difference in two expansion plans that have the same reliability. One of the expansion plans included the DSM option and the other expansion plan did not include the DSM option. This computed difference defines the capacity impact for the DSM option and is the Maximum Net Dependable Capability (MNDC).

Using the PROMOD results for the change in production cost, MNDC capacity of the DSM option, and entering them with the DSM financial data into TIPS, the B/C ratios are computed. Appendix IX-1 includes a description of each model used in Cumulative Option Analysis.

The parameters used in the Rate Impact Measure (RIM) test were: production cost; capacity cost; marketing cost; administrative cost; advertising cost; equipment cost; customer credit costs; and revenue impacts. The parameters used in the Total Resource Cost (TRC) test were: production cost; capacity cost; marketing cost; administrative cost; advertising cost; equipment costs; and customer direct cost. The parameters used in the Participant test (PART) are: revenue impacts; customer direct costs; and customer credit cost. The parameters used in the Utility Cost test (UC) are: production cost; capacity cost; marketing cost; administrative cost; equipment cost; and customer credit costs.

The DSM options and respective benefit/cost ratios for each economic test are provided in Exhibit 9-7. The DSM options are presented in the same order the options were ranked in Single Option Analysis and analyzed in the Cumulative Option Analysis. The ranking was presented in Exhibit 9-6.

Exhibit 9-7: CUMULATIVE OPTION ANALYSIS RESULTS

	BENEFIT/COST RATIO TEST			
DEMAND-SIDE OPTION NAME	PARTICIPANT	RATE IMPACT MEASURE (RIM)	TOTAL RESOURCE COST (TRC)	UTILITY COST (UC)
IS - Start in 2000	31.53	1.39	19.28	1.37
SG W/Backfeed 1500 KW/Cus	[1]	1.32	8.02	1.32
HE Unitary Equip for A/C	2.53	0.61	1.34	2.41
Res LC - A/C	20.51	1.47	4.28	1.47
HE Chillers for A/C	13.74	0.79	9.98	5.65
Non-Res HE Ltg - Electric Htg - New	14.81	0.79	10.82	14.85
Res Off Peak W/H - Submetered	55.97	0.11	0.33	0.35
SG - Cat C	[1]	1.42	5.86	1.42
Non-Res HE Ltg - Electric Htg - Existing	2.96	0.83	2.42	16.33
SG CIP $10,000/Cus	3.26	0.35	0.45	0.35
Res HVAC Tune-Up	5.66	0.75	4.03	4.39
Res LC - W/H	11.00	0.27	0.50	0.27
Non-Res HE Ltg - OPT - New	29.02	0.66	17.77	24.04
Res W/H Blanket	[1]	0.52	10.06	10.06
Non-Res HE Ltg - Fossil Htg - New	21.04	0.61	11.45	16.77
Non-Res HE Ltg - Fossil Htg - Existing	4.20	0.62	2.54	17.93
Non-Res HE Ltg - OPT - Existing	5.80	0.64	3.64	24.41
Motor Systems - $6/HP	6.23	0.75	4.08	6.06

[1] No customer cost currently associated with these options.

In addition to the DSM options presented in Exhibit 9-7, it became apparent that multiple alternative plans would be required since no single economic test is used at Duke. The results of two additional DSM options that were analyzed, such that various alternative plans could be developed, are given in Exhibit 9-8.

Exhibit 9-8: ADDITIONAL CUMULATIVE OPTION ANALYSIS RESULTS

DEMAND-SIDE OPTION NAME	BENEFIT/COST RATIO TEST		
	PARTICIPANT	RATE IMPACT MEASURE (RIM)	TOTAL RESOURCE COST (TRC)
Non-Res. H.E. Indoor Lighting - High[1]	6.64	0.58	3.55
Motor Systems - $25/HP	7.36	.60	4.01

[1] Sum of three Non-Residential High Efficiency Indoor Lighting - High Scenarios

9.4 Integration Results

To develop one or more alternative plans, an integration of the Cumulative Option Analysis results, purchased resources and the Base Supply-Side Plan was required. This integration required the use of an optimization planning model (PROVIEW) to optimize the Base Supply-Side plan options, DSM options and purchased resources. The optimization results then represent an alternative plan using the available resources to meet customers' needs without considering the risks or uncertainty of assumptions.

This year's results of the integration process resulted in three alternative plans -- scenarios -- based on the application of the RIM and TRC economic tests. The three scenarios are described below.

Scenario #1:

Scenario #1 includes all DSM programs presented as part of the existing system, all DSM options with B/C ratios greater than one for the RIM test and two commercial DSM options to address customer class equity. Exhibit 9-9 lists the DSM programs and options included, while Exhibit 9-10 provides the corresponding supply-side expansion plan and MNDC of all DSM programs or options.

Scenario #2:

Scenario #2 includes all DSM programs presented as part of the existing system and all DSM options with B/C ratios greater than one for the RIM or TRC test. Exhibit 9-9 lists the DSM programs and options included, while Exhibit 9-11 provides the corresponding supply-side expansion plan and MNDC of all DSM programs or options.

Scenario #3:

Scenario #3 includes all DSM programs and options presented in Scenario #2 but includes an increased MW and GWH penetration in the commercial and industrial lighting and motors systems sectors. Exhibit 9-9 lists the DSM programs and options included, while Exhibit 9-12 provides the corresponding supply-side expansion plan and MNDC of all DSM programs or options.

Standby Generator-Capacity Improvement - $10,000 Payment/Customer was the only new DSM option with a B/C ratio less than one for the RIM and TRC test. Therefore, this option was not included in any of the scenarios. For comparisons, Exhibit 9-9 also includes a list of the DSM programs included in the Base Supply-Side Plan. More detail on the Base Supply-Side Plan is provided in Exhibit 9-5. Each of the scenarios are passed to Risk Assessment and discussed in further detail.

Exhibit 9-9: DEMAND-SIDE OPTIONS INCLUDED IN ALTERNATIVE PLANS

	Base Supply-Side Plan	Scenario		
		#1	#2	#3
Res Insulation New Resid	X	X	X	X
Res Insulation Loan	X	X	X	X
Res Dual Fuel HP	X	X	X	X
HE Freezer - Res	X	X	X	X
HE Refrig - Res	X	X	X	X
HE Heat Pump - Res	X	X	X	X
HE Central A/C - Res	X	X	X	X
Res Off Peak W/H - Submetered	X	X	X	X
Res LC - A/C	X	X	X	X
Res LC - W/H	X	X	X	X
IS	X	X	X	X
SG W/O Backfeed	X	X	X	X
IS - Start in 2000		X	X	X
HE Unitary Equip for A/C		X	X	X
HE Chillers for A/C		X	X	X
SG W/Backfeed 1500 KW/Cus		X	X	X
SG - Cat C		X	X	X
Res HVAC Tune-Up			X	X
Res W/H Blanket			X	X
Non-Res HE Ltg - New and Existing[1]			X	
Motor Systems - $6/HP			X	
Non-Res HE Ltg - High[2]				X
Motor Systems - $25/HP				X

[1] Sum of six new and existing market Non-Residential High Efficiency Indoor Lighting cases
[2] Sum of three Non-Residential High Efficiency Indoor Lighting - High Scenarios

Exhibit 9-10: SCENARIO #1 ALTERNATIVE PLAN

	Supply-Side			Demand-Side
Year	74MW CT (MW)	128MW CT (MW)	1200 MW Coal (MW)	Cumulative MNDC[1] (MW)
1992				1183
1993				1273
1994				1337
1995				1527
1996				1664
1997	444			1723
1998	74			1978
1999	592			1994
2000		128		2224
2001		512		2367
2002		128		2737
2003			1200	2652
2004				2646
2005		256		2746
2006		512		2798

[1]Maximum Net Dependable Capability

Exhibit 9-11: SCENARIO #2 ALTERNATIVE PLAN

Year	Supply-Side			Demand-Side
	74MW CT (MW)	128MW CT (MW)	1200 MW Coal (MW)	Cumulative MNDC[1] (MW)
1992				1185
1993				1327
1994				1469
1995				1617
1996				1681
1997	74			2102
1998				2442
1999	518			2503
2000		128		2841
2001		256		3033
2002		384		3257
2003		384		3471
2004		384		3434
2005		384		3615
2006			1200	3684

[1]Maximum Net Dependable Capability

Exhibit 9-12: SCENARIO #3 ALTERNATIVE PLAN

	Supply-Side			Demand-Side
Year	74MW CT (MW)	128MW CT (MW)	1200 MW Coal (MW)	Cumulative MNDC[1] (MW)
1992				1189
1993				1282
1994				1450
1995				1617
1996				1681
1997				2142
1998				2486
1999				3089
2000				3511
2001		256		3863
2002		128		4197
2003		256		4500
2004		384		4518
2005		256		4758
2006		640		4780

[1]Maximum Net Dependable Capability

Supply-Side Sensitivity Analysis

This analysis uses an optimization planning model (PROVIEW or EGEAS). For example: To study the effect of doubling the capital cost of a coal unit, an optimization model is used. Likewise, halving the cost of gas or oil fuel for a combustion turbine also requires an optimization planning model.

DSM Sensitivity Analysis

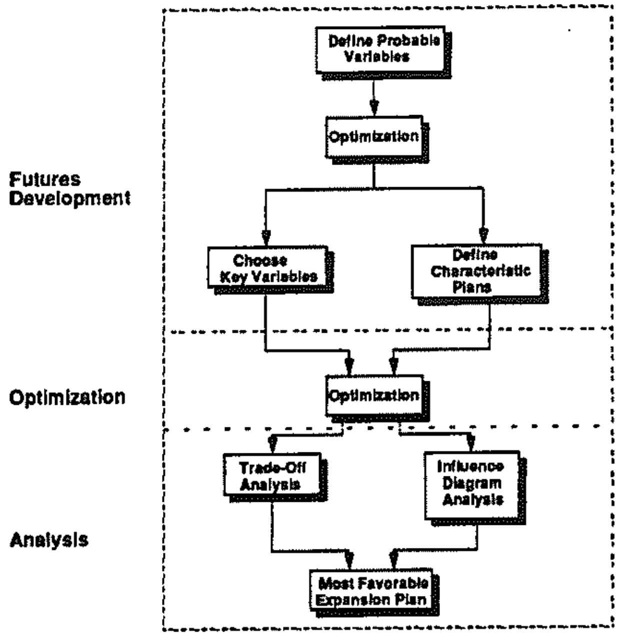
This analysis involves several models and an economic analysis spreadsheet. For example: analyzing a higher DSM lighting option penetration required a chronological model (ENPRO), a production costing model (PROMOD) and a Duke developed economic analysis spreadsheet (TIPS) to provide the present worth economic calculations. Another sensitivity, doubling the DSM expenses, simply involves TIPS.

Limit Analysis

This analysis expands on the Sensitivity Analysis technique by examining multiple combinations of key planning assumptions to broaden the vision of what the future may hold. This analysis will determine a range of possible outcomes instead of predicting precisely what the future will hold. By studying plans with multiple combinations of key assumptions, it is possible to identify those options which economically meet the range of possible outcomes. The final recommendation may not be the lowest cost plan for any one possible future outcome, but it will be one of the lowest cost plans for a wide variety of potential future outcomes. In this way, a robust plan is identified that offers the flexibility to be economical under a wide variety of future conditions.

Limit Analysis consists of three major steps: 1) Futures Development; 2) Optimization; and 3) Analysis. Each of the steps also have several intermediate steps. The Limit Analysis process is shown in Exhibit 10-2.

Exhibit 10-2: LIMIT ANALYSIS PROCESS



Futures Development starts by defining a list of probable assumptions that may effect the expansion plan. An analysis is performed using an optimization planning model (EGEAS) and the resulting total costs and supply-side additions are reviewed. From the review, a list of key assumptions are chosen along with several characteristic plans.

A characteristic plan key assumption is the commercial operation date for the first baseload addition. The intent of each characteristic plan is to capture a probable expansion plan.

The number of key assumptions and number of characteristic plans must be limited since a detailed optimization analysis is performed for all high and low combinations of each key assumption and for each characteristic plan. For example: four key assumptions and four characteristic plans requires a total of 64 optimization planning model runs.

Each combination of key assumption and a characteristic plan is a future scenario and is analyzed in the Optimization step. While holding the timing of the first baseload addition constant, the optimization model is allowed to choose all additional baseload and/or peaking generation.

After optimization of all future scenarios, the associated production costs, capital costs, and total costs are analyzed to determine those plans which have favorable economics across the various future conditions. A distinction is made between plans which appear to be good alternatives in a few future conditions and those plans which appear as good alternatives for many future conditions. This Analysis step is performed using Trade-Off and Influence Diagram methodologies. The results help develop the final conclusions for the timing of the first baseload addition and supply-side options included in the IRP.

Scenario Analysis

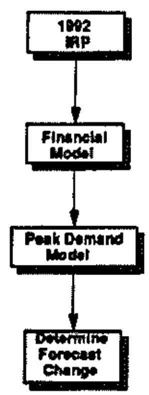
This analysis differs from Sensitivity or Limit Analysis in that several different expansion plans are constructed with certain aspects of the scenarios reviewed in detail. In this study, scenarios were developed to analyze the interaction between various levels of achievement in DSM resources and the resulting supply-side expansion plan. Each of the plans were compared to determine the capacity and energy mix of demand and supply options, the cost to provide the energy to meet customer needs and the impact on air emissions.

After all Sensitivity Analysis, Limit Analysis and Scenario Analysis techniques are completed, an IRP is developed. The only remaining technique is Portfolio Analysis.

Portfolio Analysis

This analysis determines if the resources included in the Integrated Resource Plan have a significant impact on the cost of electricity as compared to those costs used to develop the forecast. A change in the cost of electricity could change the forecast significantly. If this occurred, the integration and risk assessment process would have to be redone. Exhibit 10-3 shows the process used in Portfolio Analysis.

Exhibit 10-3: PORTFOLIO ANALYSIS PROCESS DIAGRAM



By comparing the financing requirements of the IRP with the financing requirements used to develop the original forecast, the impact on the cost of electricity is computed. Given a new projection on the cost of electricity, a modified forecast is developed. This "closes the loop" on the planning process by determining if the process created an IRP that will significantly change a key assumption, the forecast.

10.3 Risk Assessment Details

10.3.1 Sensitivity Analysis

Sensitivity Analysis determines the effects of a single change to a critical planning assumption. By varying the value of a key assumption, the sensitivity of the overall plan to that key assumption is determined. Sensitivity Analysis is composed of two parts: 1) Supply-Side Sensitivity Analysis and 2) DSM Sensitivity Analysis. The results of the supply-side sensitivities also provide a screening tool in determining which assumptions to include in Limit Analysis.

Supply-Side Sensitivities

A group of experts from various departments within Duke created a list of key assumptions based on their experience. The objective of the group was to focus on those key assumptions that could have the most impact on future expansion plans. These key assumptions are given in Exhibit 10-4 as the supply-side sensitivites. At the same time, the group decided on an applicable high and low value for each key assumption. The value assigned was based on an 80 percent confidence factor that the future would occur within the range defined by the high and low value. Each set of high and low values, shown in Exhibit 10-4, represents a change to the nominal value.

Exhibit 10-4: SUPPLY-SIDE SENSITIVITIES

Sensitivity	High	Low
Forecast Load Growth Rate	183%	75%
Load Factor	+3%	-3%
Coal Fuel Price Escalation	200%	50%
Oil Fuel Price Escalation	200%	50%
1200 MW Coal Capital Cost	125%	80%
800 MW Coal Capital Cost	125%	80%
Combustion Turbine Capital Cost	125%	90%
Combined Cycle Capital Cost	125%	80%

An optimization planning model(EGEAS) was used to optimize the mix of future supply-side additions. The model used Pulverized Coal - 1200 MW; Combustion Turbines - 74 and 128 MW; Combined Cycle - 400 MW; Pulverized Coal - 800 MW; and Diesel Generator - 25.6 MW as the supply-side options available as expansion alternatives. A brief description of the results are tabulated in Exhibit 10-5. The Base Supply-Side Plan details have been provided in Exhibit 10-5 for comparison.

Exhibit 10-5: SUPPLY-SIDE SENSITIVITY RESULTS

Sensitivity	First 1200 MW Fossil (Year)	PWRR ($M)	Total Coal (MW)	Total CT (MW)	Alternate[2] Technologies (Yes/No)
Base Supply Side Plan	2003	38,644	1200	3670	No
Forecast Load Growth Rate - High	2001	55,997	4800	4640	No
Forecast Load Growth Rate - Low	2009	32,258	0	2492	No
Load Factor - High	2002	40,865	2400	2902	No
Load Factor - Low	--	36,567	0	4640	No
Coal Fuel Price Escalation - High	2004	44,599	1200	3670	No
Coal Fuel Price Escalation - Low	2003	36,460	1200	3872	No
Oil Fuel Price Escalation - High	2002	39,620	2400	2774	No
Oil Fuel Price Escalation - Low	2004	38,053	1200	3872	No
1200 MW Coal Capital Cost - High	--	38,962	1600	3744	Yes
1200 MW Coal Capital Cost - Low	2002	37,483	2400	3286	No
800 MW Coal Capital Cost - High[1]	2003	38,644	1200	3670	No
800 MW Coal Capital Cost - Low	--	37,735	1600	3542	Yes
Combustion Turbine Capital Cost - High	2003	38,977	2400	3488	No
Combustion Turbine Capital Cost - Low	2004	38,502	1200	3798	No
Combined Cycle Capital Cost - High[1]	2003	38,644	1200	3670	No
Combined Cycle Capital Cost - Low[1]	2003	38,644	1200	3670	No

[1]No change from Base Supply-Side Plan
[2]As compared to the technologies selected in Base Supply-Side Plan

Forecast Growth Rate: The expansion plan was extremely sensitive to the forecast growth rate. When the forecast growth rate was escalated at 183 percent of the nominal, the first baseload fossil addition moved 2 years from 2003 to 2001 and resulted in approximately equal amounts of coal and CT additions. When the forecasted growth rate was escalated at 75 percent of the nominal, the first baseload fossil addition moved 6 years from 2003 to 2009 and all supply-side additions, for the next 15 years, consisted of CTs. None of the alternative supply-side options were chosen.

Load Factor: A 3 percent increase in the load factor moved the first baseload fossil addition from 2003 to 2002 and resulted in approximately equal amounts of coal and CT additions. A 3 percent decrease in the load factor moved the first baseload addition outside the 15 year horizon. The ratio of CT to coal additions remained 3 to 1, the same as the Base Supply-Side Plan. None of the alternative supply-side options were chosen.

Coal Fuel Price Escalation: When the coal fuel price was escalated at twice (200 percent) the nominal rate, the first baseload fossil addition moved one year from 2003 to 2004. Halving (50 percent) the nominal escalation rate did not move the first baseload addition from 2003. The ratio of CT to coal additions remained 3 to 1, the same as the Base Supply-Side Plan. None of the alternative supply-side options were chosen.

Oil Fuel Price Escalation: When the oil fuel price rate was escalated at twice (200 percent) the nominal rate, the first baseload fossil addition moved one year from 2003 to 2002 and additional coal construction was cost effective. This resulted in approximately equal amounts of coal and CT additions. Halving (50 percent) the nominal escalation rate moved the first baseload addition one year from 2003 to 2004 and caused no real change to the ratio of CT to coal additions. None of the alternative supply-side options were chosen.

1200 MW Coal Capital Cost: At 125 percent of the nominal capital cost, none of the 1200 MW coal options were built within the study timeframe. The supply-side baseload option switched to the 800 MW coal option with the first addition occuring in 2003. Approximately the same MW of CTs were built as compared to the Base Supply-Side Plan. At 80 percent of the nominal capital cost, the first 1200 MW fossil addition was moved one year from 2003 to 2002 with a second coal addition before 2006. The CT additions decreased slightly as compared to the Base Supply-Side Plan. None of the remaining alternative supply-side options were chosen.

800 MW Coal Capital Cost: At 125 percent of the nominal capital cost, the future expansion plan remained the same as the Base Supply-Side Plan. At 80 percent of the nominal capital cost, the baseload additions switched from the 1200 MW coal option to the 800 MW coal option. The CT MW additions remained approximately the same as compared to the Base Supply-Side Plan. None of the remaining alternative supply-side options were chosen.

Combustion Turbine Capital Cost: At 125 percent of the nominal CT capital cost, the first coal addition remained in 2003 with an additional unit included before 2006. This reduced the amount of CTs that were constructed. At 90 percent of the nominal CT capital cost, the coal addition moved one year from 2003 to 2004 while the amount of CTs built remained approximately the same as the Base Supply-Side Plan. None of the alternative supply-side options were chosen.

Combined Cycle Capital Cost: Increasing the cost to 125 percent or decreasing the cost to 80 percent created no change as compared to the Base Supply-Side Plan.

In addition to the supply-side sensitivities presented in Exhibit 10-4 and 10-5 three additional supply-side concerns were analyzed. A brief description and results are provided below:

Alternative Supply-Side Options: Several alternative options were studied to address supply-side concerns. These options were not included in the Base Supply-Side Plan analysis since their costs as compared to other options were high. However, these options were considered important and the additional analysis was to confirm that the screening curve analysis presented a true picture of the options costs and benefits. The risk assessment supply-side options were presented in Exhibit 7-13 and included: Nuclear LWR - 1200 MW; Pumped Storage - 800 MW; Pulverized Coal - 400 MW with FGD; Advanced Batteries - 20 MW; Atmospheric Fluidized Bed Combustion (AFBC) - 400 MW; and Circulating Fluidized Bed Combustion - 400 MW. As the result, none of the alternative supply-side technologies were chosen in the optimization planning model(PROVIEW) analysis.

Impacts of Retirement Schedules: The retirement of baseload coal and nuclear units currently on the Duke system will have a major impact on future resource needs. However, none of the retirements are in the 15 year planning horizon. Considering the magnitude of the impact, several sensitivites were performed to determine if there were near term implications due to possible resource needs outside the 15 year horizon. In these sensitivities, retirement schedules were varied for three cases: 1) No nuclear retirements within 30 year horizon; 2) No fossil retirements within 30 year horizon; and 3) No nuclear or fossil retirements through a 30 year horizon. The analysis was performed using an optimization planning model (PROVIEW). As a result of the sensitivities, there were no changes to the supply-side options in the 15 year horizon due to coal or nuclear retirements. These changes included the timing of the baseload additions, the MW of combustion turbines constructed and the supply-side options selected.

Multi-Unit Options: Due to the large size, large capital expenditures associated with a 1200 MW coal addition and possible operating benefits of a smaller size addition, Duke performed a sensitivity to address coal addition size and the possibility of a multi-unit addition. For this sensitivity, two 600 MW coal units were considered instead of a single 1200 MW unit addition. As a result of the analysis, using an optimization planning model (PROVIEW), the multi-unit technology (two 600 MW units) replaced the single 1200 MW unit additions.

Demand-Side Sensitivities

The DSM sensitivities that were studied and the results are in Exhibit 10-6. The results indicate if the sensitivity would change the inclusion of the DSM option into the IRP.

Exhibit 10-6: DEMAND-SIDE SENSITIVITIES

Sensitivity	Result Summary
Half DSM Expenses	No change in RIM or TRC.
Double DSM Expenses	No options pass RIM. All options pass TRC.
Triple DSM Expenses	No options pass RIM. SG w/Backfeed 1500 KW/Cus and HE Unitary Equip for A/C no longer pass TRC.
Half MNDC	SG w/Backfeed 2000 KW/Cus only option to pass RIM. SG w/Backfeed 1500 KW/Cus and HE Unitary Equip for A/C no longer pass TRC.
Half MNDC for IS and Res LC-A/C starting in 1995	Neither option passes RIM. Both options pass TRC. Additional CTs required before 2000.
Alternate SG Options	SG w/Backfeed 1000 KW/Cus passes RIM and TRC. SG w/Backfeed 2000 KW/Cus passes TRC but does not pass RIM. SG w/Backfeed 500 KW/Cus does not pass RIM or TRC.
Res Off Peak W/H-Flat Pay	Option passes RIM and TRC.

10.3.2 Limit Analysis

Limit Analysis is comprised of three sections: Futures Development, Optimization and Analysis. Limit Analysis expands on the Sensitivity Analysis by examining multiple combinations of key assumptions to broaden the vision of what the future may hold. Instead of predicting what the future will hold, Limit Analysis determines a plan that meet a wide range of possible outcomes.

For this year's study, the list of assumptions that may impact future expansion plans were shown in Exhibit 10-4 as supply-side sensitivities. These assumptions were chosen by consulting the experts within Duke.

From the sensitivity results, four characteristic plans were defined. The years 2001, 2003, 2006 and 2009 were chosen to be characteristic of the timing of the first baseload additions. These became the characteristic plans.

In addition, the sensitivities were used to choose four key assumptions. Load growth rate, coal capital cost, coal price escalation rate and oil price escalation rates were chosen. These assumptions were chosen by considering the PWRR and timing of the first baseload addition.

Sixty-four cases were created by developing all possible high/low combinations of the four key assumptions into a "future" and subjecting each "future" to each characteristic plan. The cases were then analyzed using an optimization model (EGEAS). The optimization model was allowed to commit all future baseload and peaking additions required except the first baseload addition defined by the characteristic plan.

After optimization of all future scenarios, the total costs (PWRR), capital cost and production cost, with consideration of different forecasts, were analyzed to determine those plans which have favorable economics across the various future conditions. Therefore, a future scenario which is favorable in these conditions should also be favorable for a less extreme condition. This analysis included Trade-Off and Influence Diagram methodologies.

The results of Limit Analysis indicated that the timing of the first baseload addition is driven almost entirely by the forecast. The eight high load forecast growth rate futures dictated a baseload addition in 2001 while the eight low load forecast growth rate futures dictated baseload additions in 2009. This led to the conclusion that there was not sufficient justification to warrant changing the timing of the 2003 baseload addition determined in the Base Supply-Side Plan.

10.3.3 Scenario Analysis

In Scenario Analysis, three alternative scenarios were developed based on various levels of DSM accomplishments. In addition to the 3 alternative scenarios, the Base Supply-Side Plan was included for a total of four. The 3 alternative scenarios were created by the integration process. A MW comparison for each of the scenarios are provided in Exhibit 10-7 while Exhibit 10-8 explicitly defines the DSM options included. A detailed MW comparison and detailed supply-side plan for each scenario was given in section 9.4.

Exhibit 10-7: MW SCENARIO COMPARISONS THROUGH 2006

	Base Supply-Side Plan	Scenario #1	Scenario #2	Scenario #3
1994 Cumulative DSM (MW)	1144	1337	1469	1450
2000 Cumulative DSM (MW)	1371	2224	2841	3511
2006 Cumulative DSM (MW)	1380	2798	3684	4780
Cumulative 74MW CTs (MW)	1110	1110	592	--
Cumulative 128MW CTs (MW)	2432	1536	1920	1920
2003 Pulverized Coal (MW)	1200	1200	--	--
2006 Pulverized Coal (MW)	1200	--	1200	--

Exhibit 10-8: DSM OPTIONS INCLUDED IN EACH SCENARIO

	Base Supply-Side Plan	Scenario		
		#1	#2	#3
Res Insulation New Resid	X	X	X	X
Res Insulation Loan	X	X	X	X
Res Dual Fuel HP	X	X	X	X
HE Freezer - Res	X	X	X	X
HE Refrig - Res	X	X	X	X
HE Heat Pump - Res	X	X	X	X
HE Central A/C - Res	X	X	X	X
Res Off Peak W/H - Submetered	X	X	X	X
Res LC - A/C	X	X	X	X
Res LC - W/H	X	X	X	X
IS	X	X	X	X
SG W/O Backfeed	X	X	X	X
IS - Start in 2000		X	X	X
HE Unitary Equip for A/C		X	X	X
HE Chillers for A/C		X	X	X
SG W/Backfeed 1500 KW/Cus		X	X	X
SG - Cat C		X	X	X
Res HVAC Tune-Up			X	X
Res W/H Blanket			X	X
Non-Res HE Ltg - New and Existing[1]			X	
Motor Systems - $6/HP			X	
Non-Res HE Ltg - High[2]				X
Motor Systems - $25/HP				X

[1] Sum of six new and existing Non-Residential High Efficiency Indoor Lighting cases.
[2] Sum of three Non-Residential High Efficiency Indoor Lighting - High Scenarios.

These plans were created to determine the impacts of alternative DSM achievements. As is demonstrated in Exhibit 10-7, the supply-side resource additions are dependent on the level of DSM achievement. Exhibit 10-9 provides graphical comparisons of capacity for the four scenarios while Exhibit 10-10 provides the anticipated range of Sulfur Dioxide emissions for the scenarios.

Exhibit 10-9: FUTURE CAPACITY COMPARISON

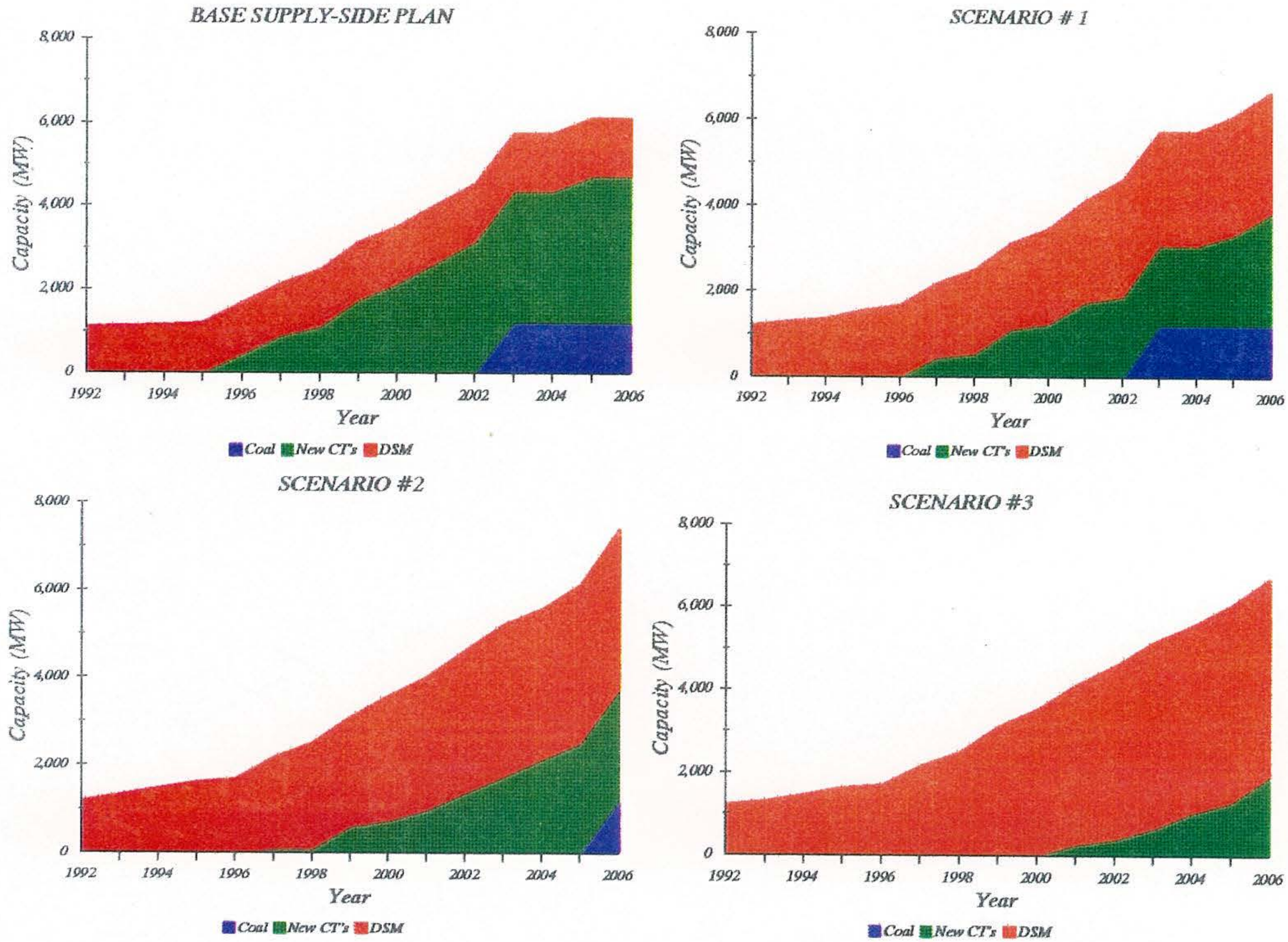
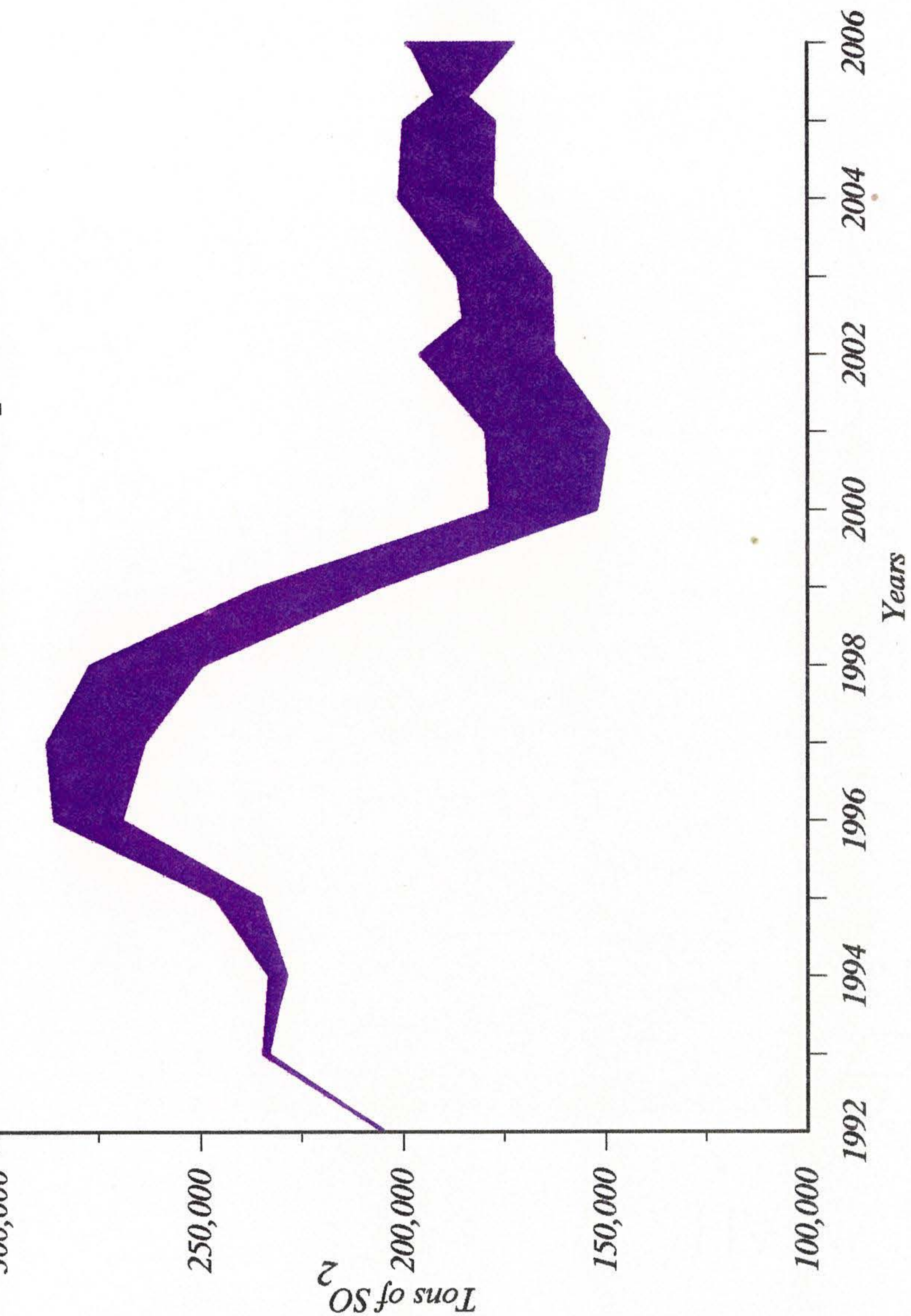


Exhibit 10-10: PROJECTED RANGE OF SO_2 EMISSIONS



10.3.4 Portfolio Analysis

Portfolio Analysis determines if the financial requirements contained in the selected Integrated Resource Plan have a significant impact on the cost of electricity as compared to those costs used in the initial forecast. This "closes the loop" on the planning process by determining if the process created a significant change to a key assumption, the forecast.

The results of Portfolio Analysis indicated a change of less than 1.5 percent over the study period. This change results in about 0.1 percent change per year and would not have an impact on the resources selected and presented in the 1992 Integrated Resource Plan.

10.4 Results

The 1992 Integrated Resource Plan (IRP) was developed by merging the results from Resource Integration (9.4) with the results of Sensitivity, Limit and Scenario Analysis. This merging results in the IRP that will be valid under a wide variety of future conditions and provide the greatest flexibility to meet future needs and adjust to the ever changing assumptions. These uncertainties and risks of the unknown future were a concern to Duke in the development of the 1992 IRP.

Scenario #2 presented in section 10.3.3 was recommended as the 1992 Integrated Resource Plan. However, this recommendation is pending the outcome of several piloted DSM options. This plan:

- Delays the decisions on supply-side capacity additions.
- Represents a reasonably achievable amount of DSM capacity.
- Positions Duke in the strategically important energy efficiency markets. Specifically motors systems and lighting.
- Has lower cost than Scenario #3.
- Has sufficient DSM accomplishments to move the first baseload addition from 2003 to 2006.

Scenario # 2 was modified before it became the 1992 IRP. Two of the DSM options included in Scenario #2 were removed: Standby Generation with Backfeed and Standby Generation - Category C. These programs were removed due to questions about their technical and economic viability. The capacity associated with these programs is minimal and their removal does not have a significant impact on the expansion plan.

Additionally, the baseload fossil addition required in conjunction with Scenario 2 will be comprised of two 600 MW units, rather than a single 1200 MW unit. The first unit will have a commercial operation date of 2006 with the second unit available for the 2007 peak.

11.0 1992 INTEGRATED RESOURCE PLAN (IRP)

11.1 Plan Summary

The 1992 Integrated Resource Plan (IRP) is the culmination of a year-long process that evaluates Duke Power's system needs over the next 15 years. The IRP incorporates existing and scheduled resources along with Demand-Side, Supply-Side and Purchased resource options to determine a proposed course of action over that 15 year period to ensure that the demands of the service area will be economically and reliably met in compliance with environmental regulations.

The results of the 1992 IRP show that additional supply-side resources are not required to be in place before 1995. The combination of the current forecast, growing Demand-Side programs and return of the Plant Modernization Program (PMP) fossil units provides Duke additional time to make firm decisions regarding the construction of the Lincoln Combustion Turbine Station (LCTS) and allows time for piloting aggressive Demand-Side programs. The programs include energy efficiency programs such as motor systems and commercial and industrial lighting.

Additional resources will be required during the planning horizon. The IRP shows that a combination of Demand-Side programs coupled with combustion turbines will provide the best selection of resources through most of the 15 year time period. Near the end of the planning horizon Duke anticipates a base load technology will be required. Currently this technology is most economically met with coal fired resources. However, the baseload decision is not near-term. Future integrated resource plans will address the type and need of additional baseload capacity. Due to anticipated advances in construction techniques, licensing and air emission advantgages with respect to fossil fired alternatives, nuclear power may receive increased consideration as a potentially viable baseload solution.

This IRP calls for a significant amount of piloting of DSM options over the next several years. This is because a pilot may take several years to address the uncertainties or other concerns being targeted. Upon completion of the pilot, the option will be reanalyzed.

Exhibit 11-1 provides a summary of the Supply-Side resources and cumulative effect of the available DSM options presented in the 1992 IRP. Major strides in the effective use of DSM options are evident in this IRP. Of the six new DSM options included, Non-Residential High Efficiency Indoor Lighting and Motor Systems are seen as the major avenues to Duke's DSM success.

Exhibit 11-1: 1992 Integrated Resource Plan

	Supply Side			Demand-Side
Year	74MW CT (MW)	128MW CT (MW)	600MW Coal (MW)	Cumulative MNDC[1] (MW)
1992				1165
1993				1305
1994				1459
1995	296			1599
1996	296			1641
1997	592			2065
1998				2313
1999				2431
2000				2750
2001				2958
2002		256		3194
2003		384		3403
2004		128		3582
2005		512		3611
2006			600	3689

[1]MNDC = Maximum Net Dependable Capability

Exhibit 11-2 provides a graphical representation of the capacity mix of the future resources that are represented in the 1992 IRP. Exhibit 11-3 provides a graphical projection of the energy usage of the DSM and supply-side resources to be added in the future.

Exhibit 11-2: CAPACITY MIX FOR FUTURE RESOURCES

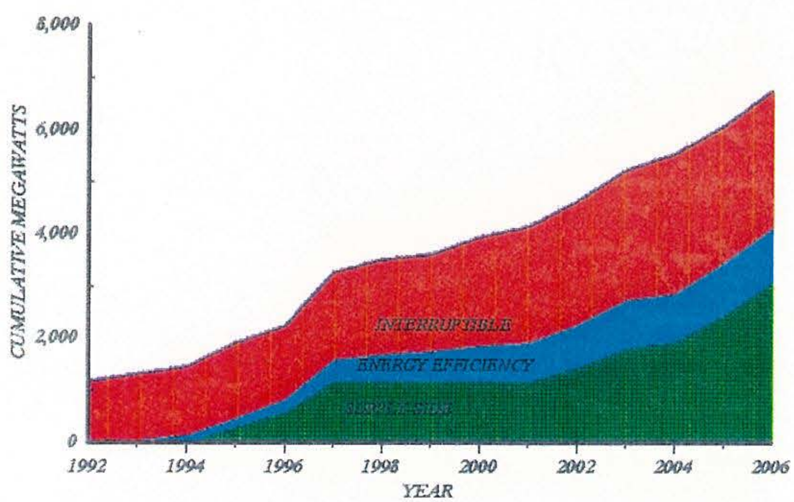


Exhibit 11-3: ENERGY PROJECTION FOR FUTURE RESOURCES

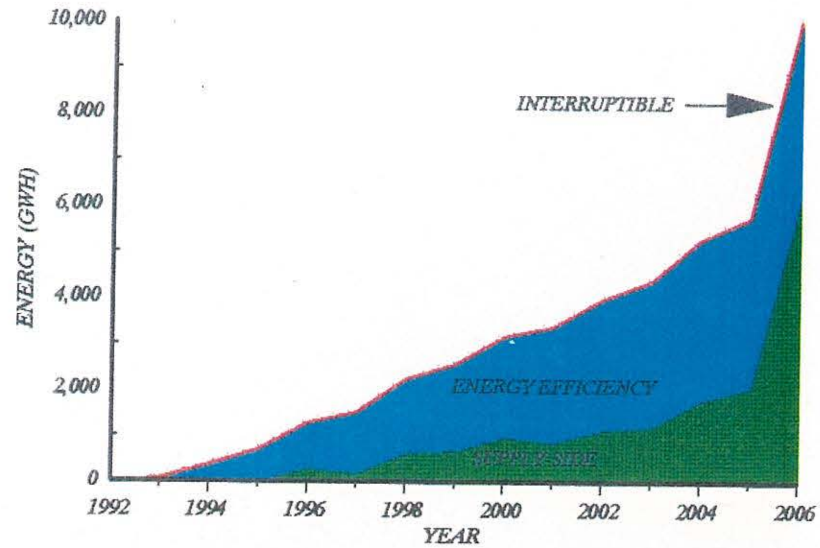


Exhibit 11-4 shows a projection of the capacity factor for different groupings of existing and future generating units on the Duke system. Note the increased reliance on older fossil units to provide the additional energy consumed in the later years. This increase is due to increased energy sales without additional baseload options being added to the system.

Exhibit 11-4: CAPACITY FACTOR PROJECTION

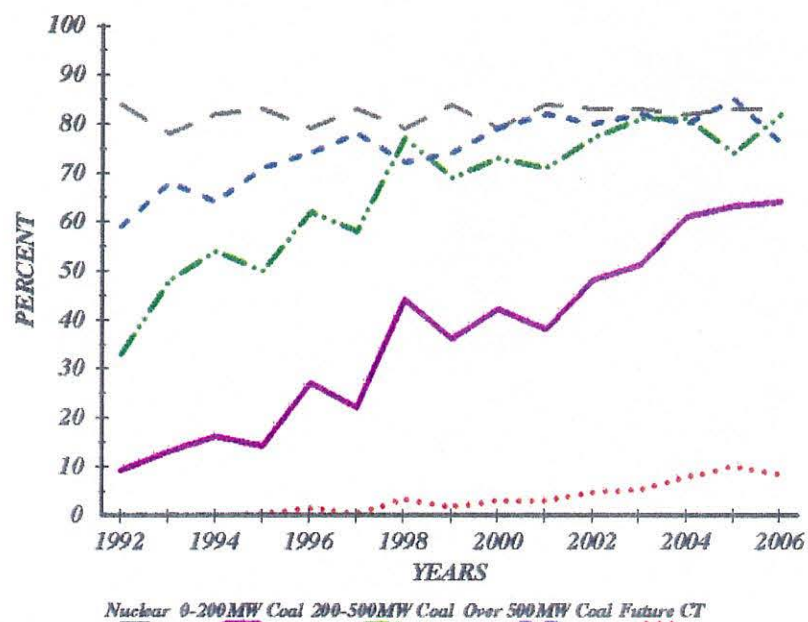


Exhibit 11-5 provides the projections of emissions for SO_2 and NOx for the 1992 IRP.

Exhibit 11-5: SO_2 AND NOx EMISSION PROJECTIONS

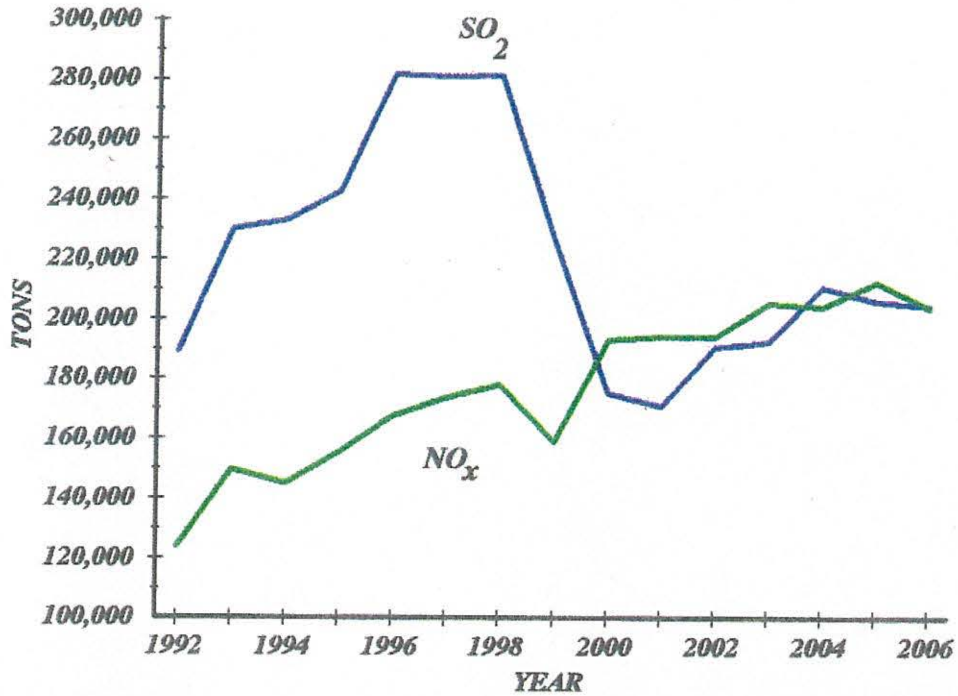


Exhibit 11-6 shows the resources in the 1992 IRP for the 15 year planning horizon in a Load, Capacity and Reserves Table. Several data assumptions have changed since June 1991 when the integrated planning work was performed. These assumptions are discussed in detail in the notes following Exhibit 11-6.

EXHIBIT 11-6: PROJECTIONS OF LOAD, CAPACITY, AND RESERVES
FOR DUKE POWER COMPANY AND NANTAHALA POWER & LIGHT

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1 DUKE SYSTEM FORECAST PEAK	14,852	15,169	15,549	15,990	16,383	16,798	17,248	17,724	18,069	18,519	18,949	19,429	19,772	20,185	20,590
2 NP&L SYSTEM FORECAST PEAK	137	140	143	147	150	153	157	160	163	167	170	174	178	181	184
3 COINCIDENT DUKE/NP&L	14,983	15,303	15,687	16,131	16,527	16,946	17,399	17,877	18,226	18,679	19,113	19,596	19,943	20,359	20,768
4 DUKE GENERATING CAPACITY	17,712	17,712	17,915	18,029	18,325	18,621	19,213	19,213	19,213	19,213	19,213	19,213	19,213	19,213	19,213
5 NP&L GENERATING CAPACITY	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
6 PMP RETURNS	0	203	114	0	0	0	0	0	0	0	0	0	0	0	0
7 SCHEDULED ADDITIONS	0	0	0	296	296	592	0	0	0	0	0	0	0	0	0
8 CAPACITY RETIREMENTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(67)
9 TOTAL GENERATING CAPACITY	17,812	18,015	18,129	18,425	18,721	19,313	19,313	19,313	19,313	19,313	19,313	19,313	19,313	19,313	19,246
10 CUMULATIVE PURCHASES	493	493	493	293	293	293	293	293	293	293	293	293	293	293	293
11 CUMULATIVE SALES	0	(400)	(400)	(400)	(400)	(400)	(400)	0	0	0	0	0	0	0	0
12 UNSCHEDULED CAPACITY															
CT'S	0	0	0	0	0	0	0	0	0	0	256	384	128	512	0
COAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
13 TOTAL PRODUCTION CAPACITY	18,305	18,108	18,222	18,318	18,614	19,206	19,206	19,606	19,606	19,606	19,862	20,246	20,374	20,886	21,419
14 GENERATING RESERVES - MW	3,322	2,805	2,535	2,187	2,087	2,260	1,807	1,729	1,380	927	749	650	431	527	651
15 RESERVE MARGIN	22.2%	18.3%	16.2%	13.6%	12.6%	13.3%	10.4%	9.7%	7.6%	5.0%	3.9%	3.3%	2.2%	2.6%	3.1%
16 CAPACITY MARGIN	18.1%	15.5%	13.9%	11.9%	11.2%	11.8%	9.4%	8.8%	7.0%	4.7%	3.8%	3.2%	2.1%	2.5%	3.0%
17 CUMULATIVE DSM CAPACITY	1,165	1,305	1,459	1,599	1,641	2,065	2,313	2,431	2,750	2,958	3,194	3,403	3,582	3,611	3,689
18 TOTAL EQUIVALENT CAPACITY	19,470	19,413	19,681	19,917	20,255	21,271	21,519	22,037	22,356	22,564	23,056	23,649	23,956	24,497	25,108
19 EQUIVALENT RESERVES - MW	4,487	4,110	3,994	3,786	3,728	4,325	4,120	4,160	4,130	3,885	3,943	4,053	4,013	4,138	4,340
20 RESERVE MARGIN	29.95%	26.86%	25.46%	23.47%	22.56%	25.52%	23.68%	23.27%	22.66%	20.80%	20.63%	20.68%	20.12%	20.33%	20.90%
21 CAPACITY MARGIN	23.0%	21.2%	20.3%	19.0%	18.4%	20.3%	19.1%	18.9%	18.5%	17.2%	17.1%	17.1%	16.8%	16.9%	17.3%

NOTES TO EXHIBIT 11-6

The following notes are numbered to match the line numbers on the 1992 INTEGRATED RESOURCE PLAN.

2. The Duke Power Company and Nantahala Power & Light systems were interconnected upon completion of the Shuler line on October 1, 1990.
3. Planning is done for the coincident peak demand for the two systems.
5. Nantahala hydro capacity was added on October 1, 1990.
6. Plant Modernization Program (PMP) capacity returns to service per the March 1991 schedule.
7. The schedule additions are those approved for construction. The additions shown are for the 74 MW Lincoln Combustion Turbine Station units. The dates of operation will remain flexible to accommodate changes in resource needs.
8. There are no firm schedules for unit retirements. The 67 MW retirement shown in 2006 represents a retire/replace/refurbish decision date for Dan River Steam Station Unit #2.
10. Cumulative purchases have several components. All years include the following purchases from SEPA, customer generation (COGEN), and small power producers (SPP):

SEPA	238
COGEN & SPP	55
TOTAL	293

An additional contract for 200 MW of capacity is shown in 1992 through 1994.

11. Cumulative sales represent the CP&L sale.
12. Unscheduled capacity represents new capacity resources or capability increases which are being considered. Neither the date of operation, the type of resource, nor the size is firm. All capacity additions beyond 1997 represent that required to maintain the 20% minimum planning reserve margin. The CTs shown in this period are the 128 MW Advanced CTs.
15. Reserve margin is shown for reference.
16. Capacity margin is the industry standard term. A 16.67 percent capacity margin is equivalent to a 20.00 percent reserve margin.
17. Cumulative DSM capacity represents the demand-side management contribution toward meeting the load. The DSM programs reflected in these numbers include interruptible, designed to be activated during capacity shortage situations, load shift, and energy efficiency programs. The value shown is the amount of maximum net dependable capability that these DSM programs have displaced.

Assumption Updates for Exhibit 11-6

Several assumptions used in the integrated planning process have been updated since the work was performed in 1991. Exhibit 11-6 contains the updated data. The following notes describe the assumptions used in the planning process as compared to those reflected in Exhibit 11-6. The notes are numbered to match the line numbers in Exhibit 11-6.

5. Nantahala Power and Light generating capacity assumed 99 MW was available for all years of the study. Exhibit 11-6 now reflects 100 MW.

8. A capacity retirement of 30 MW in 1998 represented a removal of "increased pumped hydro capability" due to high-head operation at Jocassee. A capacity retirement of 172 MW in 1998 represented a removal of high-head operation at Bad Creek. Based on analysis of forecast changes and DSM programs, Duke has discontinued the high-head operation and adjusted the capacity of Jocassee and Bad Creek to fully utilize their impoundments. This will make the capacity of these plants consistent with the license ratings. Exhibit 11-6 line 4 now reflects that the "increased pumped hydro capability" has been removed from the system.

10. The customer generation (COGEN) and small power producers (SPP) capacity was assumed to be equal to 48 MW. Exhibit 11-6 reflects 55 MW.

11. The 400 MW CP&L sale was assumed to occur from 1992 through 1997. Exhibit 11-6 reflects the sale occurring from 1993 through 1998.

The effects of these updates do not change the results determined by the planning process that are presented in this document.

11.2 Demand-Side Contributions

Exhibit 11-7 provides a list of the existing DSM programs and new DSM options that will be implemented as programs starting in 1992. The projected MW and MWH accomplishments are provided for each DSM program.

Exhibit 11-7: DSM PROGRAMS IN 1992 IRP

	MW			MWH		
	1994	2000	2006	1994	2000	2006
Res LC - W/H	(46.2)	(65.5)	(70.2)	0	0	0
Res LC - A/C	(682.9)	(1,178.7)	(1,353.8)	0	0	0
Res Off Peak W/H	(16.6)	(24.6)	(24.6)	0	0	0
H.E. Heat Pump - Res	(3.7)	(3.7)	(3.7)	(8,558)	(8,558)	(8,558)
H.E. Central A/C - Res	(1.3)	(1.3)	(1.3)	(1,601)	(1,601)	(1,601)
Res Dual Fuel HP	(24.3)	(36.5)	(36.5)	30,438	45,762	45,762
H.E. Freezers - Res	(.2)	(.2)	(.2)	(1,844)	(1,844)	(1,844)
H.E. Refrigerators - Res	(.4)	(.4)	(.4)	(2,909)	(2,909)	(2,909)
Res Insulation New Resid	(20.2)	(74.6)	(74.6)	87,864	324,269	324,269
Res Insulation Loan	(0.7)	(1.1)	(1.1)	(16,463)	(27,438)	(27,438)
IS	(566.5)	(660.9)	(1,038.5)	0	0	0
SG W/O Backfeed	(54.4)	(92.7)	(110.1)	0	0	0
H.E. Chillers for A/C	(8.9)	(43.8)	(70.4)	(21,655)	(106,729)	(171,695)
H.E. Unitary Equip for A/C	(4.9)	(19.1)	(33.5)	(3,598)	(13,998)	(24,463)

Exhibit 11-8 provides a list of the DSM options that will be piloted starting in 1992. The projected MW and MWH accomplishments if the pilots are implemented into programs are provided for each DSM option.

Exhibit 11-8: DSM PILOTS IN 1992 IRP

	MW			MWH		
	1994	2000	2006	1994	2000	2006
Res W/H Blanket	(2.7)	(4.7)	(4.7)	(30,954)	(53,065)	(53,065)
Res HVAC Tune-Up	(5.5)	(51.2)	(51.2)	(11,470)	(105,930)	(105,930)
Non-Res H.E. Ltg - El Htg - Existing	(26.9)	(107.4)	(188.0)	(78,258)	(313,032)	(547,805)
Non-Res H.E. Ltg - El Htg - New	(12.3)	(49.3)	(86.3)	(35,906)	(143,625)	(251,345)
Non-Res H.E. Ltg - Fossil Htg - Existing	(25.7)	(102.7)	(179.7)	(109,359)	(437,435)	(765,511)
Non-Res H.E. Ltg - Fossil Htg - New	(24.7)	(98.9)	(173.1)	(105,344)	(421,377)	(737,409)
Non-Res H.E. Ltg - OPT - Existing	(13.4)	(53.7)	(94.0)	(86,176)	(344,704)	(603,233)
Non-Res H.E. Lgt - OPT - New	(3.0)	(12.0)	(20.9)	(19,210)	(76,838)	(134,467)
Motor Systems - $6/HP	(24.4)	(170.5)	(267.9)	(142,095)	(994,667)	(1,563,047)

11.3 Supply-Side Contributions

Before the year 2000, Duke will need additional capacity to meet customer demand. The supply-side option that most economically meets the near-term needs is peaking capacity. This peaking capacity is best served by combustion turbines (CTs). In the near-term, 74 MW combustion turbines prove effective in meeting the capacity needs and will also provide a benefit of quick start capability to meet spinning reserves. Around the turn of the century 128 MW CTs will be used as the most economical means to meet the peaking needs.

The 74 MW CTs presented in the 1992 IRP and in the 1990 and 1991 Short-Term Action Plans are the Lincoln Combustion Turbine Station units. The 1992 IRP shows a construction schedule of four units by 1995, four additional units by 1996 and eight additional units by 1997. The Short-Term Action Plan provides a list of the major milestones to accomplish this schedule.

Near the end of the planning horizon Duke anticipates a base load technology will be required. Currently this technology is most economically met with coal fired resources. However, the baseload decision is not near-term. Future integrated resource plans will address the type and need of additional baseload capacity. Due to anticipated advances in construction techniques, licensing and air emission advantgages with respect to fossil fired alternatives, nuclear power may receive increased consideration as a potentially viable baseload solution.

11.4 Resource Strategies

The resource options shown in this IRP are more than Duke is anticipated to need in order to meet the demand and energy requirements of the service area through 2006. There are two major reasons for this resource "duplication." The first reason is that the selected resources do not require commitments today because reserves appear to be adequate for the next several years and each option has relatively short lead times for implementation. This has allowed Duke the opportunity to maintain a great deal of flexibility in this IRP by developing a resource menu consisting of demand-side programs and combustion turbine options.

Secondly, as outlined in Section 2.4.3 there are a number of key issues facing Duke over the next fifteen years. The resource options needed to meet the demand and energy requirements of the service area will be determined, in large part, by the outcome of these issues.

12.0 SHORT-TERM ACTION PLAN

12.1 Introduction

This Short-Term Action Plan (STAP) details the actions Duke will undertake over the next three years to implement the 1992 IRP and improve the planning process. The STAP was developed based on the flexibility needed to meet future demand and energy requirements in a cost-effective manner.

Duke's strategy for the next three years will involve developing the integration of options available in this IRP by focussing on the following objectives:

1992 IRP Implementation Objectives

- Continue necessary preparations to achieve a 1995 operation date for the first phase of the Lincoln Combustion Turbine Station.
- Develop and implement pilot projects for designated demand-side options.
- Implement new demand-side programs designated in the IRP through internal means or competitive bidding.
- Continue existing demand-side programs designated in the IRP through internal means or competitive bidding.

Actions and Activities of the Planning Process

- Continue to monitor and evaluate developments regarding environmental externalities.
- Continue to identify reliability and efficiency improvements to existing generating and power delivery facilities.
- Continue to improve end-use forecasting techniques.
- Continue to improve screening and modeling techniques used in the planning process.

Details of the STAP are summarized in the sections that follow.

12.2 Demand-Side Actions

12.2.1 Programs

As a result of the 1992 IRP, Duke will implement two new DSM programs: High Efficiency Chillers for Air Conditioning and High Efficiency Unitary Equipment for Air Conditioning. The chiller program is scheduled for commission filing in the first quarter of 1992 with implementation in the second quarter. The unitary A/C program is scheduled for commission filing in the second quarter of 1992 with implementation either late in the second quarter or early in the third quarter.

12.2.2 Pilot Projects

Three pilots were completed since the last Short Term Action Plan:

-Non-Residential Heat Treating Load Shift
-Industrial High Efficiency Dust Collection
-Standby Generator With Backfeed

The results and recommendations concerning each pilot is included in Appendix VI-3.

As a result of the 1992 IRP, three new pilots will be filed with the commissions and begin the piloting process in 1992:

-Residential HVAC Tune-Up
-Motor Systems
-Residential Water Heater Insulating Blanket

During the period covered by this STAP, seven pilots will be completed. The pilots and their completion dates are shown in Exhibit 12-1: Pilot Completion Dates.

Exhibit 12-1: PILOT COMPLETION DATES

Pilot	Completion Date (Yr)
-Residential High Efficiency Lighting	1992
-Residential Water Heater Insulating Blanket	1992
-Non-Residential Air Conditioning Load Control	1992
-Residential High Efficiency Ground Coupled Heat Pump	1993
-Residential HVAC Tune-Up	1993
-Non-Residential Air Conditioning Load Shift (Cool Storage)	1993
-Non-Residential High Efficiency Indoor Lighting	1994

The Motor Systems pilot will begin research in 1992. Other target dates have yet to be determined. These dates should be available for inclusion in the 1993 STAP.

Each annual planning process has the potential to determine the need for additional pilot programs. As they are identified, they will be included in the subsequent plan.

12.2.3 Accomplishments - Current and Projected

The reported megawatt accomplishments of the existing programs through December, 1991 are listed in Exhibit 12-2.

Exhibit 12-2: DSM PROGRAM ACCOMPLISHMENTS TABLE (UPDATED AS OF DEC. 31, 1991)

Programs	Reductions Total MW	Type of Program
Residential		
Residential Load Control-Water Heater	30.5	Interrupt
Residential Load Control-Air Conditioning	373.2	Interrupt
Residential Controlled Off Peak Water Heating	9.1	Load Shft
High Efficiency Heat Pump Payment	1.1	Energy Ef
High Efficiency Central Air Conditioning Payment	0.5	Energy Ef
Residential Add-On (Dual Fuel) Heat Pump	0.2	Energy Ef
High Efficiency Freezer Payment	0.1	Energy Ef
High Efficiency Refrigerator Payment	0.4	Energy Ef
Residential Insulation-New Residences (2% Disc)	15.8	Energy Ef
Residential Insulation Loan	0.0	Energy Ef
Commercial/Industrial		
Interruptible Service	626.0	Interrupt
Standby Generator Without Backfeed	32.1	Interrupt
Total	1089.0	

Projected DSM accomplishments for the existing and new programs/pilots for 1992, 1993 and 1994, are listed in Exhibit 12-3. Values in parentheses are reductions.

The Residential Water Heater Insulating Blanket option was analyzed in resource integration as being implemented as a program in 1992. Instead, this option will be piloted in 1992. Therefore, the projected DSM accomplishments are postponed by one year and will not begin until 1993. This is shown in Exhibit 12-3.

The kilowatts (KW) in Exhibit 12-3 are the diversified customer's load at time of Duke's system peak plus transmission and distribution (T&D) line losses. The KW values for each year are cumulative not incremental. The megawatt-hour (MWH) values are annual values and include T&D line losses. The direct expenditures are also annual values.

EXHIBIT 12-3: DSM PROJECTED ACCOMPLISHMENTS TABLE

	1992			1993			1994		
EXISTING PROGRAMS	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)	CAPACITY (2) (KW)	ENERGY (3) (MWH)	DIRECT (3) EXPENDITURES ($)
RES LC-W/H (1)	(37,913)	0	4,787,838	(42,849)	0	5,051,776	(46,196)	0	5,465,324
RES LC-A/C (1)	(494,936)	0	17,719,853	(598,415)	0	19,715,767	(682,858)	0	22,225,197
RES OFF PEAK W/H	(13,253)	1,763	1,000,554	(15,180)	3,525	994,645	(16,565)	5,288	1,069,236
HE HEAT PUMP-RES	(2,353)	(5,429)	1,450,230	(3,708)	(8,558)	1,656,178	(3,708)	(8,558)	13,402
HE CENTRAL A/C-RES	(834)	(1,016)	469,709	(1,315)	(1,601)	535,594	(1,315)	(1,601)	0
RES DUAL FUEL HP	(6,170)	7,785	2,731,188	(14,150)	17,779	4,169,631	(24,256)	30,438	5,439,344
HE FREEZER-RES	(130)	(1,125)	176,286	(239)	(1,844)	213,781	(239)	(1,844)	52,441
HE REFRIG-RES	(257)	(1,848)	466,137	(449)	(2,909)	516,171	(449)	(2,909)	23,307
RES INSULATION NEW RESID.	(6,253)	27,187	4,745,807	(12,869)	55,949	5,109,697	(20,210)	87,864	5,496,236
RES INSULATION LOAN	(226)	(5,488)	554,261	(452)	(10,975)	775,257	(678)	(16,463)	1,012,647
IS (1)	(566,455)	0	25,326,000	(566,455)	0	25,452,630	(566,455)	0	25,579,893
SG W/O BACKFEED (1)	(36,831)	0	1,582,012	(45,631)	0	1,934,051	(54,431)	0	2,348,107
NEW PROGRAMS/PILOTS									
HE CHILLERS OF A/C	(2,538)	(6,187)	1,075,108	(5,075)	(12,374)	1,094,212	(8,882)	(21,655)	1,662,575
HE UNITARY EQUIPMENT FOR A/C	(1,312)	(959)	434,055	(2,953)	(2,159)	536,589	(4,921)	(3,598)	650,848
RES HVAC TUNE-UP	0	0	0	(1,630)	(3,374)	1,334,104	(5,541)	(11,470)	2,756,379
RES W/H BLANKET	0	0	0	(782)	(8,844)	882,235	(1,760)	(19,899)	892,542
NON-RES HE LTG-EL HTG-EXISTING	0	0	0	(13,429)	(39,129)	3,126,387	(26,858)	(78,258)	3,170,579
NON-RES HE LTG-EL HTG-NEW	0	0	0	(6,162)	(17,953)	1,510,959	(12,323)	(35,906)	1,532,244
NON -RES HE LTG-FOSSIL HTG-EXISTING	0	0	0	(12,834)	(54,679)	3,126,175	(25,669)	(109,359)	3,164,071
NON-RES HE LTG-FOSSIL HTG-NEW	0	0	0	(12,363)	(52,672)	3,168,946	(24,726)	(105,344)	3,207,117
NON-RES LTG-OPT-EXISTING	0	0	0	(6,712)	(43,088)	1,497,579	(13,423)	(86,176)	1,519,904
NON-RES HE LTG-OPT-NEW	0	0	0	(1,496)	(9,605)	351,761	(2,992)	(19,210)	356,992
MOTOR SYSTEMS-$6/HP	0	0	0	0	0	0	(24,359)	(142,095)	23,170,234
TOTAL	(1,169,461)		62,519,038	(1,365,149)		82,754,122	(1,568,816)		110,808,619

(1) Energy changes are negligible and assumed to be zero
(2) Estimated cumulative values
(3) Estimated annual values

NOTE: Parentheses indicate reductions

12.2.4 Supply-Side Actions

Duke Power is planning for new generation capacity as part of an IRP designed to satisfy customer demand and energy requirements in a cost-effective manner while providing flexibility to respond to future variables.

Supply-side actions required to support and implement the IRP are presented below. Future supply-side system improvements and developmental activities are presented in Planning Enhancements (12.5).

Lincoln Combustion Turbine Station

The LCTS construction schedule is:

- 4 units in 1995
- 4 units in 1996
- 8 units in 1997

Duke will continue efforts to obtain all remaining permits required to start construction. Duke will perform all administrative preparations to enable a construction start in early 1993.

Advanced Combustion Turbines

Following the Lincoln Combustion Turbines, 1280 MW of advanced combustion turbines are planned.

Based on the prevailing regulatory environment and current combustion turbine technology, current estimates indicate five or six years may be needed to site, license, permit, design and construct a combustion turbine station of this type. With 2002 projected as the earliest need for this type station, no action is required during the short-term action period.

Base Load Unit

The first base load addition in this plan is a 600 MW conventional pulverized coal unit scheduled for 2006.

Based on the prevailing regulatory environment and current fossil technology, current estimates indiciate eight or nine years may be needed to site, license, permit, design, and construct a fossil unit of this type. Based on the planned need for this unit, no action is required during the short-term action period.

12.3 Purchased Power Options

Duke keeps abreast of inter-utility purchased power opportunities through periodic contacts with other utilities, selective solicitations for quotes for power, and evaluation of request for proposals from other utilities. Inter-utility purchased power opportunities are evaluated by comparison with alternatives with regard to cost, availability and reliability. The amount of capacity available for long term purchase in the southeast has decreased since 1988. The cost of capacity still available for purchase in the southeast is not currently competitive with supply side options.

Duke is currently purchasing 200 MW from Nantahala Power and Light which Nantahala has purchased from Tennessee Valley Authority. This purchase will continue through 1994.

Duke is in various stages of negotiation with the co-owners of the Catawba Nuclear Station regarding the terms and conditions for the possible transfer and replacement of a portion of the co-owner's Catawba project capacity and energy off the Duke system. The timeframe of any such transfer(s), if ultimately agreed upon by all parties, is not currently known but would not commence until the mid 1990s.

Duke is negotiating new interconnection agreements and other power contracts with neighboring utilities with whom Duke has no current agreements. These new agreements will offer more opportunities for Duke to purchase and sell on a short term basis. Duke has filed with FERC for approval of two contracts with Cajun Electric Power Cooperative; one contract for the purchase or sale of economy energy, the other contract for the purchase or sale of short term power.

Duke is revising existing agreements with other utilities. The revised agreements will include enhancements such as formula based rates, ceiling capacity charges, and contract modifications which will allow purchases as well as sales of power. The revised agreements provide more flexibility in day-to-day operations with our utility neighbors.

12.4 IRP Activities and Enhancements

12.4.1 Demand-Side Activities

Programs

Duke plans to review each existing program annually during option development. If any new data shows that projected accomplishments or costs associated with a program will change from previous analyses, the program will be revised and included in the planning process as a new option. Existing interruptible programs will receive special attention because of their size and future potential.

New Options

Duke will continue to review new technologies as potential options. They may affect a new market segment or cause an existing program to be revised.

Energy efficient options will be the major focus in the residential market. The potential for some load shift options will continue to be reviewed as technologies improve. With the improvement of efficiency levels and technologies, the potential for new options will exist. The load shift technology for the residential market is new and improving.

In the commercial sector, the emphasis will be on energy efficient and load shift options. Energy efficient options centered around the building envelope and air conditioning/heat pump units greater than 5.5 tons in size offer many opportunities. Working toward increasing the required levels of insulation and SEER values in current codes is also an avenue being investigated. Load shift technologies exist for the commercial sector, but have economic and physical limitations. Developing reasonable options may require both technology improvements and new marketing techniques.

Production and the processes that accomplish it are the most important concerns for the industrial sector. Using energy as efficiently as possible and addressing the environmental effects associated with these processes offer the greatest opportunities for new options. Duke plans to work with industrial customers to identify ways of improving the energy efficiency of their processes. Using higher efficiency equipment or changing the operational characteristics of a process are two other areas that will be investigated. With environmental legislation, industry has higher environmental standards to be addressed. To meet these standards as efficiently and economically as possible, Duke will continue to investigate options that may need to be included in the integrated planning process.

Demand-Side Bidding

As part of Duke's expanding DSM program the company is exploring a Demand-Side Bidding concept. Demand-Side Bidding involves the competitive procurement of DSM options from a third party or customer who may be able to provide such options in a better or more cost-effective manner than Duke. This concept attempts to utilize the specialized knowledge or expertise of third parties or customers to find cost-effective DSM options that may not be captured with utility-run programs.

One potential benefit of such an activity would be to reduce the cost to acquire DSM options. Another potential benefit would be to gain a larger share of the cost-effective DSM options that are available in the service area.

The current schedule calls for release of a request for proposal in the summer of 1992. Evaluation of submitted bids will take place during the fall of 1992 followed by contract negotiations with those bidders with acceptable proposals. The installation and verification of DSM options acquired through bidding is scheduled for 1993 through 1995.

Demand-Side Bidding is being run as a pilot effort to determine its effectiveness in acquiring DSM options. Continued or expanded use of the concept will be based on the results of the pilot.

DSM Resource Assessment

The total DSM Resource Assessment will be completed in 1993. A consultant will be hired in 1992 to assimilate all the data and produce the final report.

End-Use Metering

Data from the Residential/Commercial End-Use Metering project will be collected through December 1993. Industrial metering opportunities will be identified with at least one installation by the end of 1992.

Customer Surveys

Customer input and data collection in the form of surveys will be an ongoing and growing activity at Duke. Many questions about options and existing programs can be answered using surveys.

12.4.2 Planned Enhancements of the End-Use Technique

Residential End-Use

Current efforts are proceeding in two directions. During 1992, REEPS 2.0 will be used to produce a forecast which explicitly incorporates DSM accomplishments. REEPS requires only annual appliance energy usage to produce a forecast. Work will also continue on developing hourly end-use load shapes.

Demographic and load data are now available on 867 load research customer for the years 1989-1990. In addition, in the last part of 1992 twelve months of end-use metered data will become available. This data will allow for the validation of load shapes produced by the conditional demand analysis of whole house data. It will also allow for more detailed modeling of specific end-uses.

Commercial End-Use

The load profile work mentioned in Section 5.4.3 can be used to evaluate demand-side programs and options. Duke plans to develop major end-use load shapes for each of six building types (office, retail trade, education, food stores, medical, and restaurants).

EPRI's COMMEND model is currently being used to develop energy usage forecasts for the major end-uses of the six building types mentioned above. These end-uses include heating, cooling, ventilation, water heating, cooking, refrigeration, lighting and other electricity usage.

Industrial End-Use

An industrial end-use energy forecast will be developed during 1992 to assist in the evaluation of the future impact of existing and proposed DSM programs and options. The main tool to be used to project energy by end-use will be the EPRI software product INFORM, which will project energy by SIC for the following end-uses: motor drives; process heating; lighting; HVAC; and miscellaneous uses. A test version of INFORM was received in February 1992. Since INFORM is still a test version, Duke Power has initiated an informal alliance with two other utilities planning to use INFORM in order to "compare notes" and chart progress. A load shape forecast will follow the end-use energy forecast using SHAPES-PC and/or HELM-PC.

12.4.3 Supply-Side Planning Enhancements

In order to continually improve supply-side inputs into the integrated planning process, Duke intends to pursue system improvements and developmental activities.

System Improvements

Plant Modernization Program (PMP) - Five fossil units remain to be returned to service under this program. Cost and capacity needs will determine the optimum timing for completing this work.

Hydroelectric Station Improvements - Duke has performed a study of the reliability improvement and life extension potential of various repairs, replacements, and modifications at some of Duke's hydroelectric power plants. The work on each plant will be evaluated on a case-by-case basis and considered for implementation where it proves to be cost effective and prudent.

Steam Generator Replacement - The project team that has been formed to look at this issue will continue to perform conceptual designs and studies to support a decision on whether or not to replace steam generators at the McGuire and Catawba nuclear stations. The decision will consider optimum timing based on cost, unit performance, and impact on system operation and generation.

Developmental Activities

Clean Air Act - Duke is currently working on a detailed compliance plan that must be filed and approved by the Environmental Protection Agency by 1995. This plan will indicate required modifications to Duke's existing fossil units or operating practices.

Externalities - Duke will continue to monitor and evaluate developments regarding environmental externalities. Duke will continue to include the costs of environmental compliance in its assessment of resource options. Further, Duke will continue to qualitatively consider environmental effects in resource assessment. Duke will also continue to keep abreast of developments in this area.

12.4.4 Cost Tracking

During 1991 Duke implemented a comprehensive cost tracking system. This system is designed to capture the full cost associated with DSM programs, pilot projects and administration of the IRP process. The data provided by this system will be used primarily to evaluate the cost-effectiveness of DSM programs. In addition, these costs will be vital components in rate making, cost recovery and cost management. One of the enhancements planned for this activity includes a better linkage between the planning and budgeting process.

12.4.5 Demand-Side Program Evaluations

Duke has established a formal DSM program evaluation. The initial evaluations, which are still underway, focused on three of Duke's largest DSM programs: air conditioning and water heater load control and interruptible service. The results of these three evaluations are expected in 1992.

Duke began a full-scale evaluation program in 1992. The purpose of the evaluation program is to determine the actual demand and energy savings in each program as well as assess delivery mechanisms, program penetration, and customer acceptance of the programs. Duke has hired a consultant to manage the evaluation process for 1992 with a goal to internalize the process for 1993. The program involves impact, market and process evaluations of all existing, new and piloted DSM programs. The results of the evaluation process will be used to determine the cost-effectiveness of programs, to guide changes to programs, and to document program accomplishments for cost recovery and rewards.

The primary purpose of evaluation is to provide information needed to manage DSM programs. Key elements of Duke's evaluation philosophy include the following points:

- Developing detailed evaluation plans defining the key information requirements at the time that the program is fielded
- Conducting annual impact evaluations to examine program results, kw and kwh impacts and costs to reassess program cost effectiveness
- Conducting process and market evaluations at least biannually to determine how effectively programs are being implemented, both internally and externally

- Selecting the evaluation methodology that is appropriate for the circumstances and information content required
- Assuring that the analytics used within the evaluation and the results are consistent with the IRP process
- Using performance indicators to track program performance and define the need for and scope of process and impact evaluations
- Maintaining DSM program tracking systems that can support program management and evaluation
- Assuring the development of the highest quality data
- Balancing the costs of evaluation with the value of information gathered
- Realizing the synergy among the various evaluation activities that will be conducted
- Conducting pilots to define key DSM program parameters prior to full-scale implementation wherever fesible
- Maintaining flexibility realizing that methods and strategies will change over time.

12.4.6 Demand-Side Program Cost Recovery

In the Commission's May 17, 1990 order adopting the 1989 IRP, the Commission called for the utilities to file cost-recovery plans with the 1991 STAP. Duke filed a proposal which was made up of three components: recovery of DSM expenses, recovery of lost revenues, and a reward for positive IRP accomplishments. North Carolina law (N.C.G.S. 62-2(3a)) allows the NCUC to consider rewarding utilities for "efficiency and conservation which decreases utility bills." Duke reached a stipulation agreement with the NCUC Public Staff which allowed DSM expenses beyond those covered in rates to be placed in a deferral account for future rate consideration. The agreement also allows Duke to request recovery of lost revenues on a case-by-case basis, but only when offset by "found revenues." The stipulation did not address a rewards mechanism but stated that once determined, the rewards would be placed in the deferral account. The stipulation was approved by the NCUC as part of the rate case order in November 1991.

Duke reached a similar stipulation agreement with the SCPSC Staff and the Consumer Advocate in South Carolina. The stipulation established a deferral account for certain DSM expenses and lost revenues (once again, as offset by found revenues). The stipulation did not address rewards for DSM accomplishments. The stipulation was part of the South Carolina rate case order in November 1991.

Duke has proposed a rewards mechanism to the NCUC Public Staff and is working toward a stipulation agreement on the mechanism. The reward is a "shared savings" approach; that is, a portion of the net present value of the savings of the program is returned to the utility with the remainder of the savings going to the customer.

Glossary

AC. Alternating Current

AFBC. Atmospheric Fluidized Bed Combustion

AFUDC. Allowance for Funds Used During Construction

ALWR. Passive Advanced Light Water Reactor

A/C. Air Conditioning

APC. Advanced Pulverized Coal

BACT. Best Available Control Technology

BEA. Bureau of Economic Analysis

BLS. Bureau of Labor Statistics

BOD. Biochemical Oxygen Demand

BTU. British Thermal Unit

B/C. Benefit Cost Ratio

CAA. Clean Air Act

CAES. Compressed Air Energy Storage

CFBC. Circulating Fluidized Bed Combustion

CFC. Chlorofluorocarbons

COMMEND. EPRI commercial end-use energy forecasting software

CP&L. Carolina Power and Light

CT. Combustion Turbine

CWIP. Construction Work in Progress

DC. Direct Current

DSManager. EPRI DSM option evaluation software package. (See Appendix VI- 1)

DSM. Demand-Side Management

EEI. Edison Electric Institute

EGEAS. An optimization planning model

Energy Efficiency.

- **Demand-Side** Reducing energy use without reducing the amenity.
- **Supply-Side** Increasing output while using the same amount of fuel, or maintaining output while using less fuel.

ENPRO. A chronological production costing model (See Exhibit IX-1)

EPA. Environmental Protection Agency

EPRI. Electric Power Research Institute

FERC. Federal Energy Regulatory Commission

FGD. Flue Gas Desulfurization

GWH. Gigawatt-hour (a measurement of energy)

GRP. Gross Regional Product

HELM-PC. EPRI load shape forecasting software product for all customer classes

HTGR. High Temperature Gas-Cooled Nuclear Reactor

HVAC. Heating, Ventilation, and Air Conditioning

INFORM. EPRI industrial end-use energy forecasting software

IPP. Independent Power Producer

IRP. Integrated Resource Plan

IS. Interruptible Service (a DSM program)

KW. Kilowatts (a measure of demand or capacity)

KWH. Kilowatt-hour (a measure of energy)

LCIRP. Least Cost Integrated Resource Plan

LCTS. Lincoln Combustion Turbine Station

LWR. Light Water Nuclear Reactor

MMBTU. Millions of British Thermal Units

MNDC. Maximum Net Dependable Capability

MSW. Municipal Solid Waste

MW. Megawatt (a measurement of demand or capacity)

NAAQS. National Ambient Air Quality Standards

NABE. National Association of Business Economists

NCAEC. North Carolina Alternative Energy Corporation

NCUC. North Carolina Utilities Commission

NOx. Nitrogen Oxides

NRC. Nuclear Regulatory Commission

NSPS. New Source Performance Standards

NUG. Non-Utility Generator

OPT. Duke's non-residential time-of-use rate

Options. Potential DSM Programs or Supply-Side additions

PART. Participants test (See Appendix IX-2)

PC. Pulverized coal

PFBC. Pressurized Fluidized Bed Combustion

PMP. Plant Modernization Program

Pilot. Field test of DSM option on limited basis (See Appendix VI-3.2)

PSD. Prevention of Significant Deterioration

Programs. DSM options offered to the customer

PROMOD. A software package that simulates the operation of an electric utility's generating system (See Appendix IX-1)

PROVIEW. A resource optimization planning model (See Appendix IX-1)

PURPA. Public Utility Regulatory Policies Act

PWRR. Present Worth of Revenue Requirements

QF. Qualifying Facility

Rate Schedule WC. Rate schedule to administer 1/2 price off-peak water heating (See Appendix VI-2)

RDF. Refuse Derived Fuel

REEPS. EPRI residential end-use forecasting software

Resource. Method of supplying, reducing, or displacing a portion of customer needed demand & energy (KW, KWH)

Rider IS. Rate document to administer Interruptible Service Program (See Appendix VI-2)

Rider LC. Rate document to administer Residential A/C & Water Heater Load Control Program (See Appendix VI-2)

Rider SG. Rate document to administer Standby Generator Program (See Appendix VI-2)

RIM. Rate Impact Measure test (See Appendix IX-2)

PSCSC. Public Service Commission of South Carolina

RD&D. Research, Development and Demonstration

SCF. Standard Cubic Foot

SCPSC. South Carolina Public Service Commission

SEER. Seasonal Energy Efficient Ratio

SEPA. Southeastern Power Administration

SHAPES-PC. Energy Management Assoc. end-use energy and load shape software for all customer classes

SIC. Standard Industrial Classification (a government publication)

SCC. Stress Corrosion Cracking

SG. Standby Generator

SO_2. Sulfur Dioxide

STAP. Short-Term Action Plan

Technologies. Generation sources, end-uses, etc. that are potential DSM or Supply-Side options

TIPS. A Duke developed economic spreadsheet (See Appendix IX-1)

TRC. Total Resource Cost Test (See Appendix IX-2)

T&D. Transmission and Distribution

TVA. Tennessee Valley Authority

UC. Utility Cost Test (See Appendix IX-2)

VOC. Volatile Organic Compound

WEFA. Wharton Econometric Forecasting Associates

Integrated Resource
Plan
1992

VOLUME III

APPENDICES

DUKE POWER COMPANY

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Appendix 2.

Appendix II-1

STIPULATION A.1 TREAT DSM EXPLICITLY

RECOMMENDATION:

Treat DSM explicitly. The utilities should enhance their forecasting methods to allow explicit treatment of DSM potential and achievements. The utilities could adopt end-use/econometric models that explicitly account for consumption characteristics, program potential, and achievements. Such models are available from EPRI and other organizations. These models, at a minimum, should be run in parallel with the current forecasting process to explicitly track DSM potential and program impact.

PROJECT OVERVIEW:

To treat DSM explicitly in the forecasting process will require three major activities most of which are in progress.

1. Commit resources required to accomplish end-use forecasting.
2. Evaluate end-use forecasting software.
3. Have the ability to do end-use forecasting for all customer classes by December 31, 1991.

ACTION PLAN:

Action 1:

Duke plans to commit resources to adopt end-use forecasting techniques in the forecasting process. Facilities and additional equipment will be allocated to support new positions in the Forecasting department staff. Computer equipment and software will be required, as well as training for personnel intended for the end-use forecasting process.

Status: Duke has committed resources to adopt end-use forecasting through the addition of two new positions in the Forecasting department and the provision of hardware, software, and training. COMPLETED. (See Section 5.5 of the 1992 IRP)

Action 2:

Duke plans to purchase and receive software to evaluate for the utilization in the end-use forecasting technique.

Status: Duke has reviewed many software packages (including REEPS, COMMEND, INDEPTH, SHAPES-PC, HELM-PC, and SAS with HELM-PC) being used in conjunction with SAS. Duke is in the process of reviewing INFORM, which is an EPRI product for industrial purposes. COMPLETED. (See Section 5.5 of the 1992 IRP)

Action 3:

Duke plans to be able to do end-use forecasting for all customer classes by December 31, 1991 and to complete end-use analysis for some, if not all, customer classes for utilization in the 1992 IRP filing.

Status: A residential end-use appliance based forecast, which has been prepared, requires additional sample points to yield an acceptable product. Completion of this forecast is projected for December 1992. A forecast based on total whole house load shapes should be available by the end of 1991. The first month that end-use metering data was available for commercial was July 1991. Since a minimum of one year of end-use data is required for forecasting, it will be August 1992 before end-use forecasting can be done. Industrial end-use forecasts are still scheduled for December 1992. (See Section 5.5 of the 1992 IRP)

PROGRESS ASSESSMENT:

A significant amount of work has been performed toward enhancing forecasting techniques to specifically address the effects of Demand Side Programs. This work includes the addition of necessary resources, evaluation and development of analytical tools, and initial runs of end-use forecasts for residential and commercial sectors.

The original objectives were to complete the residential forecast by February 1991, commercial by November 1991, and industrial by December 1992 and to utilize these techniques in parallel with current econometric forecasts to specifically address the effects of DSM programs on system loads. The forecast used in the 1992 filing was adopted in June 1991 and, therefore, does not incorporate specific end-use techniques other than those included in the current econometric models.

Work is continuing on development of end-use techniques. Initial results from the residential study revealed results which need to be refined in order to effectively address DSM. The process of acquiring the necessary data and developing the models is more complex and detailed than initially projected resulting in some delays. These results are not unique to Duke and are being experienced by other utilities. Additional whole house data, plus data from the end-use metering project should allow the development of a full appliance based end-use forecast by December 1992. Efforts in commercial will involve disaggregating the building type load shapes into individual major end-uses. Use of INFORM as an industrial end-use tool will progress as detailed end-use data becomes available.

STIPULATION A.2 INCORPORATE FACTORS AFFECTING ELECTRICITY USE

RECOMMENDATIONS

Incorporate factors affecting electricity use. The utilities should adopt peak load models that include details on the patterns and determinants of electricity use and the effects of time-of-use electricity prices. Relevant models are available, such as Battelle's SHAPES and EPRI's HELM, which could be adapted to specific utility needs.

PROJECT OVERVIEW

To incorporate factors affecting electricity use three activities will be required.

Actions:

1. Evaluate econometric models for peak demand by revenue sub-class in the residential class, by rate schedule for the commercial class, and by SIC for the industrial class.
2. Commit resources required to accomplish end-use forecasting.
3. Evaluate end-use software and models by the divisions stated in Action 1.

ACTION PLAN

Action 1:

Duke plans to evaluate the econometric models by the appropriate sub-classification to be incorporated into the forecasting process. Through this evaluation the factors affecting these sub-classes can be determined.

Status: Duke has implemented the forecast of peaks by customer class. COMPLETED. (See Section 5.5 of the 1992 IRP)

Action 2:

Duke plans to commit resources to adopt end-use forecasting techniques in the forecasting process. Facilities and additional equipment will be allocated to support new positions in the Forecasting department staff. Computer equipment and software will be required, as well as training for personnel intended for the end-use forecasting process.

Status: Duke has committed resources to adopt end-use forecasting through the addition of two new positions in the Forecasting department and the provision of hardware, software, and training. COMPLETED. (See Section 5.5 of the 1992 IRP)

Action 3:

Duke plans to purchase and receive software to evaluate for the utilization in the end-use forecasting technique. Duke plans to be able to do end-use forecasting for all customer classes by December 31, 1991 and to complete end-use analysis for some, if not all, customer classes for utilization in the 1992 IRP filing. If some of the electricity usage trends quantified in the end-use analysis can be represented by a time series factor, then such factor will be implemented in the appropriate econometric model.

Status: Duke has reviewed many software packages (including REEPS, COMMEND, INDEPTH, SHAPES-PC, HELM-PC, and SAS with HELM-PC) being used in conjunction with SAS. Duke is in the process of reviewing INFORM, which is an EPRI product for Industrial end-use forecasting. A residential end-use appliance based forecast, which has been prepared, requires additional sample points to yield an acceptable product. Completion of this forecast is projected for December 1992. A forecast based on total whole house load shapes should be available by the end of 1991. The first month that end-use metering data was available for commercial was July 1991. Since a minimum of end-use data is required for forecasting, it will be August 1992 before end-use forecasting can be done. Industrial end-use forecasts are still scheduled for December 1992. (See Section 5.5 of the 1992 IRP)

PROGRESS ASSESSMENT:

A significant amount of work has been performed toward enhancing forecasting techniques to specifically address the effects of Demand Side Programs. This work includes the addition of necessary resources, evaluation and development of analytical tools, and initial runs of end-use forecasts for residential and commercial sectors.

The original objectives were to complete the residential forecast by February 1991, commercial by November 1991, and industrial by December 1992 and to utilize these techniques in parallel with current econometric forecasts to specifically address the effects of DSM programs on system loads. The forecast used in the 1992 filing was adopted in June 1991 and, therefore, does not incorporate specific end-use techniques other than those included in the current econometric models.

Work is continuing on development of end-use techniques. Initial output from the residential study revealed results which need to be refined in order to effectively address DSM. The process of acquiring the necessary data and developing the models is more complex and detailed than initially projected resulting in some delays. These results are not unique to Duke and are being experienced by other utilities. Additional whole house data, plus data from the end-use metering project, should allow the development of a full appliance based end-use forecast by December 1992. Efforts in commercial will involve disaggregating the building type load shapes into individual major end-uses. Use of INFORM as an industrial end-use tool will progress as detailed end-use data becomes available.

STIPULATION A.3 INCORPORATE END-USE TRENDS

RECOMMENDATION:

Incorporate end-use trends. The utilities need to examine their models to be sure that change s in equipment efficiencies and in operating practices that affect forecasts of annual electricity use are appropriately reflected in their forecasts of peak demand.

PROJECT OVERVIEW:

In order to incorporate end-use trends, the utility will have to enact three activities.

1. Commit resources required to accomplish end-use modelling and forecasting.
2. Evaluate end-use forecasting software.
3. Evaluate econometric and end-use models to incorporate end-use trends.

ACTION PLANS:

Action 1:

Duke plans to commit resources to adopt end-use forecasting techniques in the forecasting process. Facilities and additional equipment will be allocated to support new positions in the Forecasting department. Computer equipment and software will be required, as well as training for personnel intended for the end-use forecasting process.

Status: (See Stipulations A.1 and A.2 above)

Action 2:

Duke plans to purchase and receive software to evaluate for the utilization in the end-use forecasting technique.

Status: (See Stipulations A.1 and A.2 above)

Action 3:

Duke plans to do traditional end-use modelling techniques for the residential and commercial classes to evaluate end-use trends for those classes. If these trends can be represented by a time series, then the trends will be incorporated into the econometric approach. The industrial sector energy will be evaluated econometrically by SIC, and historical load shape information will be used to derive demand for the industrial sector for at least the customer class.

Status: (See Stipulations A.1 and A.2 above)

PROGRESS ASSESSMENT:

A significant amount of work has been performed toward enhancing forecasting techniques to specifically address the effects of Demand Side Programs. This work includes the addition of necessary resources, evaluation and development of analytical tools, an d initial runs of end-use forecasts for residential and commercial sectors.

The original objectives were to complete the residential forecast by February 1991, commercial by November 1991, and industrial by December 1992 and to utilize these techniques in parallel with current econometric forecasts to specifically address the effects of DSM programs on system loads. The forecast used in the 1992 filing was adopted in June 1991 and, therefore, does not incorporate specific end-use techniques other than those included in the current econometric models.

Work is continuing on development of end-use techniques. Initial output from the residential study revealed results which need to be refined in order to effectively address DSM. The process of acquiring the necessary data and developing the models is more complex and detailed than initially projected resulting in some delays. These results are not unique to Duke and are being experienced by other utilities. Additional whole house data, plus data from the end-use metering project, should allow the development of a full appliance based end-use forecast by December 1992. Efforts in commercial will involve disaggregating the building type load shapes into individual major end-uses. Use of INFORM as an industrial end-use tool will progress as detailed end-use data becomes available.

STIPULATION B.1 COLLECT DATA ON FACTORS AFFECTING ELECTRICITY USE BY CUSTOMER CLASS

RECOMMENATION:

Collect data on factors affecting electricity use by customer class. The utilities should strengthen their efforts to collect and analyze data on the determinants and patterns of electricity use (including additional customer surveys and end use load research) for each customer class. Because information on the commercial sector is especially weak, efforts should focus on this class.

PROJECT OVERVIEW

Duke is to review software for analyzing electricity use and DSM effects on customers. Software packages REEPS, COMMEND, INDEPTH, SHAPES, and HELMS are representatives of what will be evaluated for analyzing electricity use. Other packages like LOAD SHAPER and DSManager will be reviewed for determining and analyzing DSM option effects.

Customer data such as end-use usages, customer trends and usages, and construction practices will be obtained through surveys. Demographic, end-use, and load research type surveys will be used.

Actions:

1. Commit resources to and compile data from an end-use metering project to develop base data on the electrical consumption of end-uses by customer classes and types.
2. Implement customer surveys by class, type, etc. to establish base data about customer penetrations for differing types of end-uses, operational data, building envelop data, construction techniques, etc.
3. Evaluate end-use forecasting software.
4. Evaluate DSM option software.

ACTION PLAN

Action 1:

Duke will perform end-use metering by class to provide data for a base case position of electrical usage of end-uses. This base case will be used to determine energy and demand saving potential for new technologies and/or practices.

Status: All of the 500 residential and commercial sites, originally selected for end-use metering have been installed. Data from the Month of July 1991 was the first usable data from the project. The test location for industrial should be finalized in 1992. The implementation of end-use metering has taken longer than anticipated due to each step of the process taking longer than originally thought. (See Section 6.5.3 of the 1992 IRP)

Action 2:

Duke will develop and implement customer surveys to collect data on end-use penetrations, customer behavior, construction practices and trends, and other end-use and structural data. These surveys will be done by customer class, by type customer, for non-metered customer, for end-use monitored customers, and for demographics. Surveys will be done to establish base case information for the number of customers that are potential participants and to gather values to be used for establishing values for same DSM options.

Status: The residential and commercial sectors have customer surveys that have been completed with others in progress. Surveys being considered are new construction, builder, and specific end-use surveys. Industrial end uses are much more complex than residential and commercial; therefore, in 1992, Duke will begin obtaining the information and customer input to make the necessary decisions. (See Sections 6.2 and 6.5 of the 1992 IRP)

Action 3:

Duke plans to purchase and receive software to evaluate for utilization in the end-use forecasting technique.

Status: The end-use forecasting software -REEPS, COMMEND, INDEPTH, and SHAPES-PC- were evaluated in 1990. HELMS-PC is being evaluated for commercial and residential classes end-use shapes while INFORM is being evaluated for industrial end-use forecasting. (See Section 5.5.4 of the 1992 IRP)

Action 4:

Duke plans to evaluate EPRI and other software, as applicable, for use in evaluating DSM options.

Status: DSMANAGER and LOADSHAPER software packages have been evaluated and are being used to evaluate Demand-Side options. (These packages were used in developing Section 6 of the 1992 IRP)

PROGRESS ASSESSMENT:

Work related to this stipulation is still projected to be within target limits even though some start dates and final completion dates have been revised. The 1992 filing will include initial data on factors affecting electricity use by customer class. Overall completion dates may still vary due to data requirements and the completion of numerous projects related to obtaining this data.

STIPULATION B.2 CONDUCT COMPREHENSIVE DSM ASSESSMENT

RECOMMENDATION:

Conduct comprehensive DSM assessment. The utilities should conduct comprehensive assessments of the DSM resources in their service areas, along the lines of studies conducted for the New York State Energy Research and Development Authority, the Northwest Power Planning Council, the Michigan Electricity Options Study and Pacific Gas & Electric. We recommend that the utilities conduct such a project together, perhaps with the NCAEC and other interested parties, to develop estimates of conservation and load management potentials for North Carolina as a whole and for each utility service area. We recommend that the NCUC order the utilities to conduct the indicated DSM resource assessments and to complete initial studies within one year

PROJECT OVERVIEW:

The process of a DSM assessment requires current customer end-use electrical consumption patterns, new construction trends and applications, and technical data on new end-use technologies as well as new energy efficient techniques which would affect construction or energy usage. Other customer da ta about usage penetration will also be needed. Then, by taking existing electrical usages and comparing it to new techniques and/or technologies, a per unit value of potential savings in energy and demand can be derived. With existing and new construction data, the savings per unit can become an assessment of maximum potential. Much of the data obtained in regard to stipulation B.1 will be used in this process.

Actions:

1. Work with the North Carolina Alternative Energy Corporation (NCAEC) and their consultants, Barakat and Chamberlain, Inc. (BCI) to develop, if feasible, a joint utility effort for a portion of the DSM assessment needs.
2. Commit resources to compile data from an end-use metering project and to develop base data on the electrical consumption of end-uses by customer classes and types
3. Implement customer surveys by class, type, etc. to establish base data about customer penetrations for differing types of end-uses, operational data, building envelop data, construction techniques, etc.
4. Develop and complete DSM Assessment Report.

ACTION PLAN:

Action 1:

Duke will evaluate the potential of NCAEC with BCI conducting a project to establish a meaningful guideline for and recommendations for the DSM assessment. If acceptable, Duke will commit the resources and also participate in the process.

Status: Duke worked with NCAEC, BCI, and other utilities in developing three major products to establish a meaningful guideline and recommendations for the DSM assessment. The three products were: "Characteristics of Selected DSM Technologies and Measures, " A Guidebook for Conducting a Demand-Side Management Resource Assessment," and

"Summary of DSM Program Experience." This action was COMPLETED in May 1991. (See Section 6.5.2 of the 1992 IRP)

Action 2:

Duke will perform end-use metering by class to provide data for a base case position of electrical usage of end-uses. This base case will be used to determine energy and demand saving potential for new technologies and/or practices.

Status: All of the 500 residential and commercial sites originally selected for end-use metering, have been installed. Data from the Month of July 1991 was the first usable data from the project. The test location for industrial should be finalized in 1992. The implementation of end-use metering has taken longer than anticipated due to each step of the process taking longer than originally thought. (See Section 6.5.3 of the 1992 IRP)

Action 3:

Duke will develop and implement customer surveys to collect data on end-use penetrations, customer behavior, construction practices and trends, and other end-use and structural data. These surveys will be done by customer class, by customer type, for non-metered customers, for end-use monitored customers, and for demographics. Surveys will be done to establish base case information for the number of customers that are potential participants and to gather values to be used for establishing values f or same DSM options.

Status: The residential and commercial sectors have customer surveys that have been completed with others in progress. Surveys being considered are new construction, builder, and specific end-use surveys. Industrial end uses are much more complex than residential and commercial; therefore, in 1992, Duke will begin obtaining the information and customer input to make the necessary decisions. (See Sections 6.2 and 6.5 of the 1992 IRP)

Action 4:

Duke, possibly with aid of consultants, will establish the format and content of the DSM Assessment Report. After data starts becoming available on customer and/or end-uses, evaluation criteria will be finalized that will produce the value for each option discussed in the assessment.

Status: The process of establishing the evaluation and calculation procedures for each option is about two-thirds complete. Work is in progress to determine the final list of options to be included in the assessment as well as the types and formats of the data about each option. (See Section 6.5.2 of the 1992 IRP)

<u>PROGRESS ASSESSMENT</u>:

Work related to this stipulation is on schedule toward the revised dates.

STIPULATION B.3 ADOPT THE TOTAL RESOURCE COST TEST AS THE PRIMARY ECONOMIC CRITERION FOR IRP

RECOMMENDATION:

Adopt the total resource cost test as the primary economic criterion for LCIRP. We recommend that the NCUC issue an order stating its preference for the total resource cost or utility cost test (equivalent to revenue requirements) as the primary economic criterion to be used by the utilities in screening, analyzing and selecting demand and supply resources. The rate impact measure test (a version of the no losers test) should not be used to screen resources, but should be used only after integration of resources to estimate the existence and size of any adverse rate impacts.

PROJECT OVERVIEW:

A comprehensive assessment, balancing the results of multiple criteria, will be developed.

Actions:

1. Review the standard tests listed in the California Standard Practices Manual (COMPLETED May 1990).
2. Select a combination of tests which address the concerns of most parties (COMPLETED May 1990).
3. Report test results in tabular form.

Action 3:

Report test results in tabular form (target completion April 1991)

Status: Included in 1992 IRP. (See Sections 6, 7, and 9)

PROGRESS ASSESSMENT:

The 1992 IRP includes the stipulated changes.

STIPULATION C.1 INCLUDE ALL DEMAND-AND SUPPLY-SIDE RESOURCES IN INTEGRATION

RECOMMENDATION:

Include all demand and supply side resources in integration. The utilities should modify their integration methods (and models, if necessary) so that demand and supply resources compete head to head within the integration process. Several models that accomplish this integration (e.g., UPLAN, LMSTM and MIDAS) are available from EPRI and other organizations. A single integrated model need not be used if acceptable integration procedures are implemented and fully documented. A combination of tools properly applied is a perfectly acceptable -- and in some ways superior -- approach.

PROJECT OVERVIEW:

The current process uses a combination of tools to provide for head-to-head competition between proposed demand and supply-side resources. Inclusion of existing demand-side programs in the process requires the separation of incremental costs to maintain or expand the program.

The review of planning methodologies has been an ongoing process and includes evaluation of existing methods and models, review of other utilities' methods and models, investigation and development of additional modeling techniques, improvement of equipment and addition of personnel.

ACTION PLAN:

Action 1:

Evaluate existing major DSM programs against proposed demand and supply-side resources (target completion April 1991).

Status: The Short Term Action Plan filed in April 1991 included an evaluation of existing major DSM programs. COMPLETED. (See Section 6..1 of the 1992 IRP)

Action 2:

Review methods and models used by other utilities (target completion April 1992).

Status: Duke has actively investigated its planning process to identify those areas in which improvement s can be made through the use of consultants, software vendors, and other utilities. The original review has been COMPLETED. (See Section 12.5 of 1992 IRP for future enhancements)

Action 3:

Evaluate, in cooperation with a vendor, the possibility of developing an innovative modeling technique which would allow the simultaneous optimization of direct load control programs with other demand and supply-side resources (target completion April 1992).

Status: Duke is currently working with Energy Management Associates, Inc (EMA) to analyze their PROSCREEN II and PROVIEW models to allow for the simultaneous optimization of direct load control programs with other demand-and supply-side alternatives. This project is currently ahead of schedule. (See Section 12.5 of 1992 IRP for future enhancements)

Action 4:

Improve integration tools and provide necessary staff to increase ability to analyze a large number of demand-side options.

Status: As a consequence of Duke's interaction with EMA in improving and developing integration tools, EMA has committed to develop a demand side screening tool, DSView, which will be used to screen demand-side options and to integrate demand-side packages with supply-side options. (See Section 12.5 of 1992 IRP for future enhancements)

PROGRESS ASSESSMENT:

Work related to this stipulation is on target and is included in the 1992 IRP.

STIPULATION C.2 COMPARE ELECTRICITY PRICES IN THE FORECASTING & INTEGRATION STAGES

RECOMMENDATION

Compare electricity prices in the forecasting and integration stages. The utilities should compare the electricity prices produced by the integration process with those incorporated in the load forecasting models. If the two sets of prices are significantly different, enough iterations of the modeling system should be conducted to reach convergence.

Status: Duke is currently comparing electricity prices in the forecasting and integration stages. COMPLETED. (See Exhibit 10-3 of the 1992 IRP)

PROGRESS ASSESSMENT:

Duke is meeting the stipulation and anticipates no action beyond current activities.

STIPULATION C.3 INCLUDE ENVIRONMENTAL EFFECTS IN RESOURCE ASSESSMENT

RECOMMENDATION:

Include environmental effects in resource assessment. The utilities, in cooperation with the NCUC and all interested parties, should develop ways to include the environmental effects of different resources in their LCIRP processes. The filing submitted in April 1991 should incorporate these effects.

PROJECT OVERVIEW:

Duke includes costs of environmental compliance and qualitative evaluation of environmental effects in its assessment of resource options. In addition, Duke continues to stay abreast of this issue through industry conferences and publications.

Actions:

1. Continue to qualitatively consider environmental effects in resource assessment and \tab evaluate the impacts of the clean air legislation on existing and planned resources.
2. Develop an understanding of the issue of external environmental costs.

ACTION PLAN:

Action 1:

Duke will continue to consider environmental effects in resource assessment and will evaluate the impacts of the clean air legislation on existing and planned resources. Duke will report the status of this process in the 1992 integrated resource filing.

Status: Duke considers environmental impacts in the evaluation of potential generation technologies, siting of new generation facilities, and in the risk assessment. The 1992 IRP includes preliminary Clean Air Act compliance costs. (See Section 7.5.1 of the 1992 IRP)

Action 2:

Duke will form a working group to examine the issue of external environmental costs. Duke will report the status of this group's activities in the 1992 integrated resource filing.

Status: Duke has formed a working group to become educated on methods to include environmental externalities in the evaluation of their impact on Duke's system. (See Section 7.5.1 of the 1992 IRP)

PROGRESS ASSESSMENT:

The status of each action item is included in the 1992 IRP.

STIPULATION D.1 DEVELOP AND CONDUCT PROGRAM EVALUATIONS

RECOMMENDATION:

Develop and conduct program evaluations. The utilities should begin immediately to design and conduct formal outcomes and process evaluations of existing DSM programs. In addition, evaluation plans should be incorporated into all future programs (especially those included in LCIRP filings). The NCUC should order the utilities to conduct such evaluations and should require that the utilities include such evaluation plans in a revised Short-Term Action Plan.

PROJECT OVERVIEW:

Establishing a formal demand-side program evaluation process can be outlined by five major actions. Several of these are already in progress.

Actions:

1. Establish a full time position to plan and manage Duke's formal demand-side program evaluation function.
2. Develop an evaluation plan which will organize Duke's efforts, and outline comprehensive, state-of-the-art evaluation requirements for all DSM programs.
3. Commit the resources required to coordinate and/or staff formal evaluation process for demand-side programs.
4. Begin formal evaluations of several existing DSM programs following the overall evaluation strategy.
5. Establish an ongoing review of DSM program evaluation functions to implement improvements in the process that are determined to be beneficial and cost effective.

ACTION PLAN:

Action 1:

Duke will establish a full time position to plan and manage a formal demand-side program evaluation function. This will be a senior level position in the customer planning area with responsibilities for planning, organizing, and administering all program evaluation functions. This position will be independent of the organizations which are responsible for implementing Duke's programs, in order to ensure an unbiased approach to program evaluations.

Status: Duke has established a full-time position to plan and manage the formal demand-side program evaluation function. This senior level position is in the Planning and Operating organization with responsibilities for planning, organizing, and administering all program evaluation functions. The position is independent of the line organizations which are responsible for implementing Duke's DSM programs. This position was filled the first of August 1990. COMPLETE (See Section 12.4 of the 1992 IRP)

Action 2:

Duke will develop an evaluation strategy which will coordinate existing efforts, detail new requirements, and provide an overall comprehensive approach to DSM program evaluations. This strategy will utilize state-of-the-art approaches to address the financial effectiveness, performance, potential, and implementation aspects of all existing programs.

Status: Duke has developed an overall strategy for the evaluation of demand-side programs. This involved identifying the parameters which should be addressed to adequately assess individual programs, establishing a schedule for instituting program evaluations, and projecting the budgetary requirements to implement a formal evaluation process. Existing corporate evaluation expertise and database resources have been identified, along with areas where new efforts may be required. Initial efforts to develop this evaluation strategy were completed in December 1990. However, refinement of this overall strategy will occur as further program evaluation efforts are undertaken. COMPLETE (See Section 12.4 of the 1992 IRP)

Action 3:

Duke will staff as necessary to ensure the timely implementation of a formal evaluation process for demand-side programs. In addition, Duke plans to commit the resources required to contract with outside consultants to perform appropriate aspects of DSM program evaluations.

Status: In accordance with the overall evaluation strategy for demand-side programs, current staffing requires only the existing manager for program evaluation activities. This individual has responsibility for initial specification, contracting and project management requirements. Additional staffing requirements are expected as the workload increases. Appropriate outside consultant expertise has been contracted for performing the initial program evaluations. Anticipated financial resources have been budgeted for both current and future evaluation efforts. COMPLETE (See Section 12.4 of the 1992 IRP)

Action 4:

Duke expects to initiate formal DSM program evaluations for several existing programs in accordance with the overall evaluation strategy by year-end 1990. Additional evaluations will be initiated in a staggered sequence during subsequent time periods.

Status: The first formal DSM Program Evaluations were contracted August 1, 1991. Additional program evaluation efforts were contracted on September 30, 1991, closing out the work approved in Duke's January 1991 Request for Proposal. These initial evaluations are expected to be completed by June, 1992. An additional request for proposal, addressing the evaluation of the next group of DSM programs, is scheduled to be issued by Year-end 1992. (See Section 12.4 of the 1992 IRP)

Action 5:

Duke will establish an ongoing review of DSM program evaluation functions. This will be an integral part of developing the initial formal evaluation function and is expected to be a vital part of all continuing evaluation efforts. State-of-the-art techniques, which will enhance the cost-effective evaluation of DSM programs, will be incorporated into future analyses on a routine basis.

Status: Duke expects to maintain the schedule for an ongoing review of DSM program evaluations, functions and techniques. (See Section 12.4 of the 1992 IRP)

PROGRESS ASSESSMENT:

Completion of work related to this stipulation is on target. A few interim dates for interfacing with consultants have proven optimistic, but this has not affected the timeliness of the overall evaluation strategy. Initial evaluation efforts will be addressed in the 1992 IRP.

STIPULATION D.2 PROPERLY ACCOUNT FOR DSM PROGRAM COSTS

RECOMMENDATION:

Properly account for DSM program costs. The utilities should modify their accounting systems so that the costs of each DSM program can be accurately tracked.

PROJECT OVERVIEW:

Properly accounting for the costs of each DSM program will require four major activities most of which are in progress.

Actions:

1. Assess and develop a methodology to accurately track specific costs (other than labor) associated with each program.
2. Assess and develop a methodology or various methodologies to accurately track labor and overhead costs associated with each program.
3. Identify any currently available in-house cost tracking computer software system. If available, assess any programming changes required for reporting costs of each DSM program.
4. Develop and carry out an implementation plan
5. * Validate data and test cost tracking system
6. * Report the results

*Action plans added by Duke - November 1991

ACTION PLAN:

Action 1:

Duke plans to assess various methodologies to more accurately track specific costs (other than labor) associated with each program. Some of the types of costs are materials and supplies, direct purchases, automotive expenses, employee expenses, contract work, etc. From the assessment, a methodology will be developed.

Status: Duke has completed the identification of specific cost components for DSM programs and how they will be tracked. COMPETE (See Section 12.4 of the 1992 IRP)

Action 2:

(Same as Action 1 except for labor and overhead costs).

Status: (Same as Action 1) COMPETE (See Section 12.4 of the 1992 IRP)

Action 3:

Duke plans to identify any currently available in-house cost tracking computer software system. To identify a cost system, the reporting media and form must be identified, allocation methodologies must be evaluated, and data requirements must be known.

Status: Duke has completed the identification of data and reporting requirements for data collection, cost reporting forms and required programming for planning and marketing. COMPETE (See Section 12.4 of the 1992 IRP)

Action 4:

Duke plans to develop and execute an implementation plan.

Status: Duke has completed the development and execution of an implementation plan for data gathering and reporting. COMPETE (See Section 12.4 of the 1992 IRP)

Action 5:

Duke plans to test and audit the cost tracking system to ensure the validity of the results. In addition, the actual cost data being collected will be compared to the planned cost data.

Status: This is a new action added by Duke to show the need to validate and test the system which is currently under way. (See Section 12.4 of the 1992 IRP)

Action 6:

Duke plans to make the results available showing the actual costs of each load reduction, load shift, and energy efficient DSM program.

Status: This is a new Action added by Duke to show the need to report the results. This will be done upon the completion of Action 5. (See Section 12.4 of the 1992 IRP)

PROGRESS ASSESSMENT:

Accomplishments related to this stipulation were completed on time or are continuing on schedule. The first year of collecting cost data has been a learning experience where many rough areas were smoothed out. To make sure we maximize this learning experience an internal audit review is being performed on the cost tracking system. Following this review, an intense analysis of actual cost vs. planned cost will be performed. Only after such an analysis will we be prepared to report results.

STIPULATION E.1 FILE REVISED ACTION PLANS

RECOMMENDATION:

File revised Action Plans. The NCUC should order the utilities to file revised Action Plans. These revisions should include specific project milestones, budgets and departmental responsibilities. The revised Action Plans should also show how the utilities plan to respond to the other recommendations made in this chapter.

PROJECT OVERVIEW:

Duke will work with the Public Staff, to improve the Short Term-Action Plan for use by the Commission. Duke is reviewing the STAP for inclusion of milestones and near-term action items to meet the milestones in addition to DSM implementation costs.

ACTION PLAN:

Action 1:

Duke will file an updated Short Term Action Plan in April of 1991 detailing Duke's most recent Integrated Resource Plan. The STAP will include near-term action items to meet the milestones defined in the filing.

Status: The Short Term Action Plan was filed in May 1991. COMPLETE. (See Section 2.2 of the 1992 IRP)

PROGRESS ASSESSMENT:

Work related to this stipulation is complete.

STIPULATION F.1 DEVELOP PUBLIC INVOLVEMENT IN IRP

RECOMMENDATION:

Develop Public Involvement in LCIRP. The utilities should actively seek input and advice from a variety of perspectives as they develop their plans. Two alternatives which have been used successfully elsewhere are: (1) creation of an advisory committee made up of local energy experts to participate in development and review of the plan; and (2) creation of customer panels which will also review plans as they are being developed.

PROJECT OVERVIEW:

Developing public involvement in IRP can be described by two actions which are already in progress.

1. To maintain effective communication with our customers, Duke Power is conducting customer focus groups in two major areas:
   A. Attitudes and Opinions
   B. Program Design
2. Establish a Least Cost Integrated Resource Planning Advisory Committee to promote a meaningful dialogue and information exchange between Duke and the citizens of North and South Carolina on electricity supply issues.

ACTION PLAN:

Action 1:

Duke continually monitors the opinions and attitudes of the employees and customers, including builders and realtors, toward Duke Power to enable us to improve our service to the community. Duke is working with the customers to design programs that meet their needs. Duke plans to conduct focus groups on selected programs.

Status: Duke continues to monitor the opinions and attitudes of customers and employees. COMPETE (See Sections 6.2 and 6.5 of the 1992 IRP)

Action 2:

Duke will establish an Advisory Committee that will enhance the public's understanding of electricity supply issue s facing Duke and Duke's awareness of customer concerns. The Advisory Committee will review the integration process and results as Duke implements its annual Integrated Resource Planning activities. The Advisory Committee will comment on both the integration framework and the results of the process. Comments from the Advisory Committee will be forwarded to the Integration Team and to the Supply-Side and Demand-Side Teams, as appropriate, for evaluation.

Status: The Integrated Resource Planning Advisory Panel has met five times with the most recent meeting in March, 1992. (See Section 2.3.6 of the 1992 IRP)

PROGRESS ASSESSMENT:

Work related to this stipulation is on schedule. The 1992 IRP filing will include the results of public involvement in the IRP process.

STIPULATION G.1 MODIFY IRP SCHEDULE

RECOMMENDATION:

Modify LCIRP schedule. We recommend that the NCUC order the utilities to submit revised and new filings on the following schedule.

- Action Plan submitted within six months, but no later than April 1990.

  These submissions should include plans for responding to the recommendations made in this report, and could be made part of the annual updates described in Rule R8-60.

- Progress report on activities related to the implementation of the consultants' recommendations, submitted one year after the hearings, but no later than November 1990.
- New LCIRP filing submitted in April 1991.

PROJECT OVERVIEW:

Duke is pursuing the schedule as outlined in the "Duke's Response" section of this Stipulation for filing progress reports, the Short Term Action Plan and the IRP filing in April 1992.

Actions:

1. File progress reports (Status Reports) on the IRP.
2. File Short Term Action Plan in April 1991.
3. File IRP in April 1992.

ACTION PLAN:

Action 1:

Duke plans to file progress reports with the Public Staff beginning with the current November 1990 filing through April 1992.

Status: All Status Report filings are on schedule. COMPETE (See Section 2.2 of the 1992 IRP)

Action 2:

Duke plans to submit a revised Short Term Action Plan in April 1991.

Status: The Short Term Action Plan was filed in May 1991. COMPETE (See Section 2.2 of the 1992 IRP)

Action 3:

Duke plans to file a detailed IRP in April 1992.

Status: The IRP was filed in April 1992 as scheduled. COMPETE (See Section 2.2 of the 1992 IRP)

PROGRESS ASSESSMENT:

Work related to all filings is proceeding on schedule and will be included as detailed in the Status Report.

STIPULATION G.2 MODIFY IRP REQUIREMENTS FOR NP&L

RECOMMENDATION

Modify IRP requirements for NP&L. The small size and special circumstances of NP&L suggest t hat it be treated differently with respect to these rules. We recommend that the NCUC modify the LCIRP Order to allow NP&L to submit a filing tailored to its situation.

DUKE'S RESPONSE:

Not applicable.

STIPULATION G.3 REWARD UTILITY FOR POSITIVE LCIRP ACCOMPLISHMENTS

RECOMMENDATION:

Reward utilities for positive LCIRP accomplishments. We recommend that the NCUC consider and adopt methods that reward utilities for effective implementation of their LCIRP plans. The utilities and others should be invited to suggest alternative financial incentive methods.

PROJECT OVERVIEW:

The Company will request action by the Commission in its next general rate case to include expenses for IRP.

The Commission in the May 17, 1990 Order in Docket No. E-100, Sub 58 ordered that each utility file proposed plans for timely recovery of costs associated with implementation of the integrated resource plans approved by the commission.

Duke agrees with the Public Staff that programs can be developed where incentives will be allowed. Duke will work with the Public Staff toward refinement of a plan for timely recovery of costs and financial incentives associated with implementation of the integrated resource plan.

Duke believes an orderly manner to proceed would be to follow the approval of a higher level of expenditures with a subsequent analysis of the resulting plan expansion and actual expenditures to assess the potential economic merits of further incentives.

ACTION PLAN:

Duke will request that an estimated level of expenses be included in rates at its next general rate case.

Status: Duke filed the specified proposal with the April 1991 Short Term Action Plan ultimately resulting in a stipulation between Duke and the Public Staff which was signed on September 9, 1991. The North Carolina Utilities Commission rate order of November, 1991 approved placing certain DSM program expenditures associated with Commission approved programs in a deferral account. Duke continues to work with the Public Staff to determine an appropriate reward mechanism for positive IRP accomplishments. (See Section 2.2.1 of the 1992 IRP.

Work related to this stipulation is continuing.

STIPULATION G.4 PROVIDE ADDITIONAL TABULAR INFORMATION ON FORECASTS, GENERATION RESOURCES AND DSM PROGRAMS

RECOMMENDATION:

Provide additional tabular information on forecasts, generation resources and DSM programs. To facilitate access to basic information about the utilities, we recommend that the NCUC modify Rule R8-60 to clarify that the requirements for tabular data on lo ad and energy forecasts, generating capability and reserve margins, as previously required by Rule R8-43, are still required. Additionally, a summary table of annual DSM effects should also be provided.

PROJECT OVERVIEW:

Duke will provide a summary table of DSM effects in addition to tabular information on forecasts and generation resources as outlined in Rule R8-60. Work related to the inclusion of DSM information will be achieved in subsequent Short Term Action Plan filings as presented in Duke's response to Stipulation E.1 contained herein.

ACTION PLAN:

No additional action is required beyond that contained in response to Stipulation E.1.

Status: Incorporation of DSM information/effects into the Short Term Action Plan has been COMPLETED.(See Section 6.4 of the 1992 IRP)

PROGRESS ASSESSMENT:

The 1992 Integrated Resource Plan contains the stipulated DSM information. Work related to the stipulation has been met with the Short Term Action Plan and was filed with the Commission in May 1991.

Appendix II-2: DUKE POWER COMPANY INTEGRATED RESOURCE PLANNING PLANNING ADVISORY PANEL

Guidelines

1. Purpose

   The Integrated Resource Planning (IRP) Planning Advisory Panel exists to receive technical guidance, opinions, and recommendations on the integrated resource planning process from area experts outside the company through information exchange between Duke and the panel.

2. Responsibilities

   The Planning Advisory Panel will review the planning options and results as Duke Power conducts its IRP process. A minimum of four meetings will be held each year.

   The Planning Advisory Panel will review information from the three Duke IRP teams during the panel meetings. Comments and advice from the panel will be considered by the Duke teams as the IRP is developed and implemented.

   A report will be prepared annually detailing the work of the panel including documentation of the input provided by the public members and the results of the panel's suggestions.

   Minutes of the meetings will be made available to the members.

3. Membership

   Membership will include a broad representation of the public and could include representatives from business, industry, education, environment concerns, customers, etc.

   There will initially be nine public members from North and South Carolina comprising the Advisory Panel. Members will be requested to serve a minimum term of one year. The number of panel members and the composition of the panel may vary from time-to-time as needs for the level and type of public input and involvement change. The chairpersons (Duke officers) from the Supply Side, Demand Side, and Integration Teams will attend and participate in all meetings representing his/her respective area.

4. Compensation for Public Members

   Members from the public will be paid by Duke five hundred dollars ($500) for each meeting of the Advisory Panel that they attend. Payment will be made in one of the following manners to be selected by each member:

   Option 1 - A check paid directly to the member.

   Option 2 - A check paid directly to a charity designated by the member.

   Option 3 - A check paid directly to a charity selected by Duke for each member who declines Options 1 or 2.

   Duke will reimburse members for reasonable expenses associated with their attendance at the Advisory Panel meetings.

5. Duke Power Support

   Duke Power will provide staff liaison assistance for the Advisory Panel. Staff liaison responsibilities include the following:

- Coordinate and facilitate all meetings
- Provide resource assistance
- Arrange presentations as necessary
- Coordinate mailings and meetings, prepare agendas, develop and disseminate minutes of meetings
- Generally assist the committee in making its efforts efficient and productive
- Produce a report annually detailing the work of the panel.

Summary of Integrated Resource Planning Advisory Panel Meetings

June, 1991 Meeting

The initial Integrated Resource Planning Advisory Panel meetings focused on the IRP process and results. The first meeting was held in June, 1991 in Duke's general offices. The purpose of the initial meeting was to familiarize the Panel with Duke's Integrated Resource Planning process and current plans. Mr. Al Jenkins, Vice-President, Customer Planning Department, presented information about our customers in a Duke overview. Mr. Bill Reinke, Vice-President, System Planning and Operation, discussed how Duke meets energy demands on a day-by-day basis and Mr. Ted McMeekin (former Vice-President, Design Engineering and chair of the Supply Side Team) described the existing and planned capacity on the Duke System.

At the completion of the Duke overview, Mr. Reinke presented a brief history of integrated resource planning and an overall description of the planning process. Mr. Jenkins discussed Duke's method of forecasting electrical demand as well as existing and new demand-side programs. Mr. McMeekin also described the supply-side options which are considered in the integrated resource planning process. Purchased power opportunities where discussed by Mr. Reinke. The Panel had several questions about non-utility generators and wheeling issues. Mr. Reinke continued his presentation by outlining the integration process. He described how the minimum planning reserve margin was developed, how demand-side programs are placed on a level playing field with supply side options and how the plan is adjusted to account for future uncertainties.

Mr. Bill Lee also addressed the Panel at this meeting, thanking them for their participation and committing to provide feedback on all Panel suggestions. During the initial meeting, the Panel members offered specific suggestions on several DSM programs. Mrs. Martha Drake and Dr. Cuyler Dunbar suggested use of the community college system to train contractors and HVAC installers on duct leakage. As a result of this suggestion, the Company arranged a meeting with AEC, Duke personnel, and Dr. Dunbar and Mrs. Drake to look further at this idea.

September, 1991 Meeting

The second Panel meeting was held in September, 1991, at the Energy Explorium at the McGuire Nuclear Station. The Panel was brought up-to-date on the status of the IRP process. Mr. Reinke presented the base supply side plan and the cumulative ranking of the demand side options. He explained the tests (participant, rate impact measure, and total resource cost) which are used to evaluate demand side programs. Mr. Jenkins elaborated on the demand-side options which are considered in the IRP process. The Panel expressed interest in additional information on the Interruptible Service program, due to its size and importance to Duke's demand side program.

The Panel was also introduced to the concept of environmental externalities. Mr. James R. Hendricks (former Engineering Manager, Civil/Environmental Section, Design Engineering Department) defined and illustrated externalities. He outlined the various goals and methodologies in addressing environmental externalities. Mr. Hendricks also described how other states are addressing externalities and the status of the issue with the Commissions in North and South Carolina. He noted that Duke has established a working group to address the issue. The Panel requested information on the structure and role of the Utilities Commissions.

Ms. Sondra Wise of Duke's Corporate Communications Department discussed Duke's communication and education programs. She explained that the main message of Duke's programs is the wise use of electricity. She described the Company's emphasis on programs directed at young people noting that this is the best age group to influence regarding electricity use. She provided handouts of various types of advertisements Duke has used and showed a tape of ZAX (Duke's cartoon character) commercials emphasizing conservation. Ms. Wise discussed Duke's pilot program on residential compact fluorescent lights and provided each panel member with a 15W bulb. A Panel member noted that even conservation minded consumers would find the price quite steep.

Mr. Neal Stirewalt, Manager, Special Projects, presented information on Duke's proposed methodolgy for DSM cost recovery and evaluation. He discussed the background and current issues in cost recovery and evaluation. Mr. Stirewalt also discussed the broader topic of IRP evaluation to verify the results of the IRP process. A Panel member noted that recovery of DSM program costs was straight- forward, but that recovery of lost revenues and payment of incentives are bigger issues which required a more in-depth look. Another Panel member voiced a view that adjustment for lost revenues is essential for utilities to consider DSM programs.

November, 1991 Meeting

The third Panel meeting was held in November, 1991 in Greensboro, N.C. In the meeting, the status of the 1992 IRP was presented. The integration and risk assessment phases were discussed by Mr. Reinke. He provided the purpose of risk assessment and the types of risk assessment Duke performs. Mr. Reinke outlined Duke's alternatives for DSM penetration and the basis for the decision on which alternative to pursue. The Panel reviewed the plan which was presented to Duke's management later that month. Mr. Reinke requested thoughts, comments and input from the Panel on the integrated resource plan. There was much discussion from the Panel regarding Duke's need to maintain its existing units and the prospect of nuclear plant life extension. There was also discussion on the success of Duke's existing demand-side programs and the uncertainty of demand-side programs as compared to new generating facilities.

Mr. Steve Sheek, Duke's manager of Power Services, presented information on the Interruptible Service program at this meeting. He discussed the history of the program as well as the current program and issues involved in the program such as economics, testing, communications, and the future of the program. He asked for Panel thoughts and inputs. The Panel had different thoughts on whether the penalty is severe enough to ensure cooperation. The members offered several suggestions regarding testing of the program. One Panel member suggested frequent alerts with actual test interruptions, whereas another Panel member suggested surprise alerts where the customer goes through all steps except actual interruption. Another Panel member favored audit of emergency plans as sufficient for testing the program. Dr. Phail Wynn had suggested in an earlier meeting that Interruptible Service customers receive an annual summary of credits so that they can see the value of the program. Mr. Sheek reported that the suggestion is being incorporated into the program. After hearing information and issues regarding the program, a separate meeting was set to discuss the issues in more detail.

The Panel heard a presentation from Mr. A. W. Turner, NCUC Public Staff attorney, on the role and organization of the Commission in North Carolina. Mr. Turner praised the Panel for their potential role in Duke's IRP process. He told the Panel that they are an important voice in how energy needs will be met over the next several decades.

February, 1992 Meeting

The Panel met in February at Duke's division office in Greenville, S.C. Mr. Reinke updated the Panel on the status of the 1992 IRP. He told the Panel that the plan they reviewed in November was approved by Duke management in late November. He reminded the group that one key to the plan is flexibility. The Panel asked about lead time for several generating technologies. Several explored the viability of nuclear power for future generating facilities. Other points of interest with the Panel were regional planning for new generation and the potential impact of an improved economy on DSM programs. Mr. Reinke told the Panel that they would receive a draft of the 1992 IRP filing for their comments on its clarity and substance.

The Panel received an update on DSM cost recovery and externalities. On the issues of DSM cost recovery, Mr. Stirewalt reviewed Duke's proposed cost recovery mechanism. He noted that Duke was authorized in the recent rate case order in both states to place DSM costs above those approved in the rate case in a deferral account. Duke can request recovery of lost revenues in North Carolina and can propose a rewards mechanism in both states.

On the issue of externalities, Mr. Reinke explained the results of a study on the impact of externalities on the Duke system. The Panel was provided a portion of the study and Duke offered to have the appropriate Duke personnel meet with the Panel members to provide additional information to help the Panel in their focus on the issue of externalities. The Panel was asked to review Duke's proposed strategy on externalities for reasonableness. Time was set aside in two meetings to allow the Panel time to discuss the strategy and to reach a consensus. This work is not complete.

A presentation on demand side bidding was made to the Panel. The Panel was provided with a draft of Duke's demand side bidding RFP (request for proposal) and asked to comment on the readability and reasonableness of the RFP.

Ms. Marsha Ward, General Counsel with the SC PSC, discussed the organization of the SC PSC at the February, 1992 Panel meeting.

March, 1992 Meeting

The Panel met on March 18, 1992 at the new Customer Service Center in Charlotte. The March Panel meeting focused on the 1992/1993 forecast and supply side options. The Panel also began their work on externalities.

Future Meetings

Additional Panel meetings are scheduled for April, June, September, and November in various North and South Carolina locations. The April meeting will be held in Raleigh at the Industrial Energy Laboratory.

The Panel will receive an update on the current IRP activities at each meeting and will be asked for input on those activities. The April meeting will focus on demand side options for the 1992/1993 planning cycle.

The Panel will continue to focus on specific issues in integrated resource planning such as DSM cost recovery and rewards, DSM cost effectiveness tests, and the role of electrotechnologies in IRP.

Appendix 4.

Appendix IV-1: DUKE POWER CO. -- THERMAL GENERATING RESOURCES -- SUMMER, 1992

Plant/Unit	Fuel	Nameplate Capacity (MW-Gross)	Max. Net Dependable Capacity (MW)	Commercial Operation (Year)	Returned From PMP(1) (Year)
Allen 1	Coal	165.000	165	1957	1990
Allen 2	Coal	165.000	165	1957	1989
Allen 3	Coal	275.000	265	1959	
Allen 4	Coal	275.000	275	1960	
Allen 5	Coal	275.000	270	1961	
Belews Creek 1	Coal	1,080.072	1,120	1974	
Belews Creek 2	Coal	1,080.072	1,120	1975	
Buck 3	Coal	80.000	70	1941	Sched: 1993
Buck 4	Coal	40.000	38	1942	Sched: 1994
Buck 5	Coal	125.000	128	1953	1991
Buck 6	Coal	125.000	128	1953	
Buck 7C	CT: Gas/Oil	34.855	31	1970	
Buck 8C	CT: Gas/Oil	34.855	31	1970	
Buck 9C	CT: Gas/Oil	34.855	31	1970	
Buzzard Roost 6C	CT: Gas/Oil	22.700	22	1971	
Buzzard Roost 7C	CT: Gas/Oil	22.700	22	1971	
Buzzard Roost 8C	CT: Gas/Oil	22.700	22	1971	
Buzzard Roost 9C	CT: Gas/Oil	22.700	22	1971	
Buzzard Roost 10C	CT: Gas/Oil	17.833	18	1971	
Buzzard Roost 11C	CT: Gas/Oil	17.833	18	1971	
Buzzard Roost 12C	CT: Gas/Oil	17.833	18	1971	
Buzzard Roost 13C	CT: Gas/Oil	17.833	18	1971	
Buzzard Roost 14C	CT: Gas/Oil	17.833	18	1971	
Buzzard Roost 15C	CT: Gas/Oil	17.833	18	1971	
Cliffside 1	Coal	40.000	38	1940	Sched: 1994
Cliffside 2	Coal	40.000	38	1940	Sched: 1993
Cliffside 3	Coal	65.000	61	1948	1992
Cliffside 4	Coal	65.000	61	1948	1991
Cliffside 5	Coal	570.885	562	1972	
Dan River 1	Coal	70.000	67	1949	1987
Dan River 2	Coal	70.000	67	1950	1986
Dan River 3	Coal	150.000	142	1955	1989
Dan River 4C	CT: Gas/Oil	35.240	30	1967	
Dan River 5C	CT: Gas/Oil	35.240	30	1967	
Dan River 6C	CT: Gas/Oil	27.490	25	1968	
Lee 1	Coal	90.000	100	1951	
Lee 2	Coal	90.000	100	1951	
Lee 3	Coal	175.000	170	1959	

Appendix IV-2: DUKE POWER CO. -- THERMAL GENERATING RESOURCES -- SUMMER, 1992

Plant/Unit	Fuel	Nameplate Capacity (MW-Gross)	Max. Net Dependable Capacity (MW)	Commercial Operation (Year)	Returned From PMP[1] (Year)
Lee 4C[2]	CT: Gas/Oil	35.050	30	1978	
Lee 5C	CT: Gas/Oil	35.050	30	1968	
Lee 6C	CT: Gas/Oil	35.050	30	1968	
Marshall 1	Coal	350.000	385	1965	
Marshall 2	Coal	350.000	385	1965	
Marshall 3	Coal	648.000	660	1969	
Marshall 4	Coal	648.000	660	1970	
Riverbend 4	Coal	100.000	94	1952	1990
Riverbend 5	Coal	100.000	94	1952	
Riverbend 6	Coal	133.000	133	1954	1991
Riverbend 7	Coal	133.000	133	1954	Sched: 1992
Riverbend 8C	CT: Gas/Oil	33.750	30	1969	
Riverbend 9C	CT: Gas/Oil	33.750	30	1969	
Riverbend 10C	CT: Gas/Oil	33.750	30	1969	
Riverbend 11C	CT: Gas/Oil	33.750	30	1969	
Urquhart 3G	CT: Gas/Oil	15.700	15	1969	
Catawba 1	Nuclear	1,205.091	1,129	1985	
Catawba 2	Nuclear	1,205.091	1,129	1986	
McGuire 1	Nuclear	1,220.310	1,129	1981	
McGuire 2	Nuclear	1,220.310	1,129	1984	
Oconee 1	Nuclear	886.669	846	1973	
Oconee 2	Nuclear	886.669	846	1974	
Oconee 3	Nuclear	893.271	846	1974	
Total Thermal Capacity		15,746.623	15,347		
Capability In PMP		333.000	317		
Summer Thermal Capability		15,413.623	15,030		

Note:

1. PMP (Plant Modernization Program) is a program to refurbish fossil units. Units in PMP are removed from stated capacity.
2. Unit initially installed at Urquhart (4G) in 1969. Original Lee 4C unit failed and was replaced by this unit in 1978.

Appendix IV-3: DUKE POWER CO. -- HYDRO GENERATING RESOURCES -- SUMMER, 1992

Plant	Type	Nameplate Capacity (MW-Gross)	Net Firm Capacity (MW)	Commercial Operation (Year)	FERC Project No.
(Catawba River Plants)--					
Bridgewater	Conventional	20.000	23	1919	2232
Rhodhiss	Conventional	25.500	28	1925	2232
Oxford	Conventional	36.000	39	1928	2232
Lookout	Conventional	18.720	24	1923	2232
Cowans Ford	Conventional	350.000	325	1&2: 1963 3&4: 1967	2232
Mt. Island	Conventional	60.000	56	1923	2232
Wylie	Conventional	60.000	56	1925	2232
Fishing Creek	Conventional	36.720	41	1916	2232
Great Falls	Conventional	24.000	24	1907	2232
Dearborn	Conventional	45.000	36	1923	2232
Rocky Creek	Conventional	28.000	27	1909	2232
Cedar Creek	Conventional	45.000	39	1926	2232
Wateree	Conventional	56.000	74	1919	2232
(Other Plants)--					
Boyds Mill(1)	Conventional	0.960	0.11	1932	
Buzzard Roost(2)	Conventional	15.000	13.2	1966	1267
Gaston Shoals(1)	Conventional	9.140	6.27	1927	2332
Hollidays Bridge(1)	Conventional	3.500	2.23	1914	2465
Idols(1)	Conventional	1.411	0.163	1914	2585
Keowee	Conventional	157.500	174	1971	2503
99 Islands	Conventional	18.000	11.96	1910	2331
Saluda(1)	Conventional	2.400	0.515	1917	2406
Spencer Mountain(1)	Conventional	0.640	0.56	1926	2607
Stice Shoals(1)	Conventional	0.600	0.125	1970	
Turner Shoals(1)	Conventional	5.500	3	1927	
Tuxedo(1)	Conventional	5.000	3	1927	
Bad Creek	Pumped Storage	1,065.000	1,236	1991	2740
Jocassee	Pumped Storage	612.000	640	1&2: 1973 3&4: 1975	2503
Total Hydro Capability		2,701.591	2,883		
System Summer Capability		18,115.214	17,913		

Note:

1. Commercial Operation Date listed is year operated by Duke or one of its predecessors. Plant was purchased.
2. Commercial Operation date listed is year leased by Duke.

Appendix 6.

Appendix VI-1: DSManager Description

EPRI's DSManager is a database-intensive program that requires basic yearly data to define Duke-specific forecasted loads, marginal costs, generation and transmission capacity credits and rates. This data is formatted within DSManager to closely emulate the single-option analysis of the integration stage in the planning process.

Duke uses DSManager for the initial review of DSM options and revised programs. DSManager format does not lend itself to analyze options used only in the case of system capacity shortages with insignificant energy impacts. Therefore, Interruptible options were not prescreened by DSManager.

Generation capacity credits on cost per kw basis, are entered in DSManager consistent with data used by Resource Planning. Capacity credits ($/kw) for generation are entered to reflect the cost to defer an equivalent amount of combustion turbine (CT) capacity through implementation of a demand program side program. Likewise, transmission and distribution capacity credits ($/kw) are entered to equate the yearly avoided cost of transmission and distribution facilities. Credits are escalated yearly based on the projected inflation rate. Transmission capacity credits are always 100 percent. Distribution capacity credits are scaled based on the amount of demand that is supplied directly from the distribution system (versus the transmission system).

Options are designed to match DSManager's required input format, while maintaining consistency with inputs required to match the format of Resource Integration analysis tools. Load profiles are developed to represent the typical customer "before and after" implementation of the demand side program. Based on the change in energy and demand of the typical customer, DSManager can determine the total demand reduction, energy reduction, reduction in production costs and change in revenue for an entire option.

In addition to load profiles, inputs include customer rate schedules, projections of annual number of participants, and estimates of annual costs for both the customer (initial investment and O&M costs/savings) and Duke Power (capital, marketing, administrative and program payments). Composite rate schedules are created when potential participants come from different customer classes.

For all studies a base year (typically the current year) is established. This is the year to which all cost data is related through present worth analysis. Discount rates are entered in order to determine the present worth of future revenues, costs/savings and capacity credits for the Utility Cost Test, Rate Impact Measure (RIM), and Total Resource Cost (TRC) Test.

Participant Cost Test

Based on results of the tests above, the relative effectiveness of various strategies for demand-side options is determined and the most viable options are passed for use in the integrated analysis.

Appendix VI-2: Programs and Rate Schedules

The following programs and rate schedules filed with both the N.C. and S.C. Commissions are included in this appendix:

Programs

- Residential High Efficiency Heat Pump and Air Conditioning Payment Program
- Residential Add-On (Dual Fuel) Heat Pump Program
- High Efficiency Freezer and Refrigerator Payment Program
- The North Carolina Residential Insulation Loan Program
- South Carolina Residential Loan Program

Rate Schedules and Riders

- Schedule OPT
- Schedule RT
- Schedule RC
- Rider LC
- Rider IS
- Rider SG

DUKE POWER COMPANY
HIGH EFFICIENCY HEAT PUMP/CENTRAL AIR CONDITIONING
PILOT PROGRAM

PURPOSE

The purpose of the pilot program is to encourage the installation of high efficiency heat pumps and high efficiency central air conditioning systems in existing residences, to reduce the need for generation capacity, and meet the customers' needs for more efficient heating and cooling systems. The program will help the customer offset the higher installation costs of the more efficient equipment.

REQUIREMENTS TO RECEIVE PAYMENT

- Payments are available for the replacement of, or installation of, a heat pump or central air conditioning system in existing individually-metered residences.
- Availability of the program is limited to the pilot areas for customers served in Duke's Winston-Salem, North Carolina Division and Duke's Greenville, South Carolina Division.
- The customer must apply for the payment, and the heat pump or central air conditioner must be installed, between July 1, 1990 and October 31, 1990.
- The heat pump or central air conditioning system must have an Air Conditioning and Refrigeration Institute (ARI) Seasonal Energy Efficiency Ratio (SEER) rating of 10 or more.
- The system must be installed by an Authorized Comfort Machine Dealer.
- The system must be sized to within one-half (1/2) ton of cooling load.
- The maximum heat loss of the residence shall be 30 Btuh per square foot of conditioned area.
- The system must be installed to applicable building codes and in accordance with manufacturer's recommendations

PAYMENT AMOUNT

The amount of the payment for equipment with an SEER of 10 is $50 per ton for a heat pump and $40 per ton for central air conditioning. For an SEER greater than 10, the amount will be determined on a sliding scale on the basis of an additional $25 per ton for each SEER point above 10, as follows:

$$(((\text{Actual SEER} - 10) \times \$25.00)) + \$50.00))) \times \frac{\text{BTU's}}{12{,}000} = \$ \text{ Heat pump payment}$$

$$(((\text{Actual SEER} - 10) \times \$25.00)) + \$40.00))) \times \frac{\text{BTU's}}{12{,}000} = \$ \text{ Air conditioner payment}$$

Example: For a 2.5 ton heat pump with SEER of 11.4, the one-time payment is $212.50.

Duke Power Company
High Efficiency Heat Pump and Central Air Conditioning Payment Program

Purpose:

The purpose of the program is to encourage the installation of high efficiency heat pumps and high efficiency central air conditioning systems in a new or existing residence to reduce the need for generation capacity, and to meet the customers' needs for more efficient heating and cooling systems. The program will help the customer offset the higher installation costs of the more efficient equipment.

Requirements To Receive Payment

- Payments are available for the replacement of, or installation of, a heat pump or central air conditioning system in a new or existing individually-metered residence.
- Payments are available only to owners of structures receiving residential service from Duke Power's distribution system.
- The heat pump or central air conditioning system must be installed, and the Customer must apply for the payment between June 1, 1991 and May 31, 1994.
- The heat pump or central air conditioning system must have an Air Conditioning and Refrigeration Institute (ARI) Seasonal Energy Efficiency Ratio (SEER) rating of 10 or more. Minimum equipment efficiencies qualifying for payment may be increased as heating and cooling equipment technology advances.
- The system must be installed by a Duke Power Company Authorized Comfort Machine Dealer.
- The system must be sized to within one-half (1/2) ton of cooling load.
- The system must be installed to applicable building codes and in accordance with the manufacturer's recommendations.

Payment Amount

The amount of the payment for equipment with a SEER of 10 is $50 per ton for a heat pump and $40 per ton for central air conditioning. For a SEER greater than 10, the amount will be determined on a sliding scale on the basis of an additional $25 per ton for each SEER point above 10 as follows:

$$(((\text{Actual SEER} - 10) \times \$25.00)) + \$50.00))) \times \frac{\text{BTU's}}{12{,}000} = \$ \text{ Heat Pump Payment}$$

$$(((\text{Actual SEER} - 10) \times \$25.00)) + \$40.00))) \times \frac{\text{BTU's}}{12{,}000} = \$ \text{ Air Conditioner Payment}$$

Example: For a 2.5 ton heat pump with SEER of 11.4, the one-time payment is $212.50.

RESIDENTIAL ADD-ON (DUAL FUEL) HEAT PUMP PROGRAM

PURPOSE

To encourage add-on heat pumps to residential customers in existing structures. The use of high efficiency heat pumps in an add-on heat pump program helps minimize the growth of winter peak demand.

PROGRAM

Effective January 1, 1991, Duke Power will finance a high efficiency add-on heat pump used in a dual fuel system in existing residential structures through the Comfort Machine Financing Program. The financing will be available only in homes with existing fossil fuel heating systems.

DUKE POWER COMPANY
HIGH EFFICIENCY FREEZER AND REFRIGERATOR PAYMENT PROGRAM

PURPOSE

The purpose of the program is to encourage the purchase of high efficiency freezers and refrigerators by residential customers, to reduce the need for generation capacity and meet customers' needs for more efficient freezers and refrigerators. This payment program will help the customer offset the higher purchase costs for more efficient appliances.

PROGRAM

Effective January 1, 1991, payments are available for the purchase of freezers and/or refrigerators within the top 15 percent energy efficient categories as determined by analysis performed by Bonneville Power Administration. The analysis is based on how much energy the refrigerator or freezer uses relative to its size and how the model performs in comparison to other similar models. The list of qualifying refrigerators and freezers is updated every six months (April and October) and provided in published form, entitled, "The Top 15% Energy Efficient Refrigerators and Freezers," to appliance dealers and customers.

To qualify for the payment, the yellow Energy Guide label rating on an appliance must be the same as that in the published list of qualifying refrigerators and freezers. To verify that an appliance qualifies, three numbers are checked: the model number, the Energy Guide Label Rating and total volume.

PAYMENT AMOUNT

The payment for a qualifying energy efficient freezer will be $30.00.
The payment for a qualifying energy efficient refrigerator will be $55.00.

THE NORTH CAROLINA RESIDENTIAL INSULATION LOAN PROGRAM *

PURPOSE

The purpose of this program is to provide summer and winter load management benefits to Duke Power by assisting those existing residential customers who could provide meaningful demand reductions by upgrading their home insulation.

PROGRAM

To provide direct loans not to exceed $2,500 per residential unit to insulate to meet the RC rate or MAX House insulation standards, or to provide direct loans not to exceed $1,000 per residential unit to insulate to the most cost effective insulation measure. Duke will make these loans to qualified participants. Monthly payment installments will be billed and repaid through the normal billing and repayment procedures. The combination of loans to an individual owner of multiple residential units may not exceed $50,000. A surety bond or other guarantee agreement approved by Duke Power may be required from multiple residential unit owners.

SCOPE

Loans qualifying under this program will be for specific structure improvements as outlined in the details of this plan. Duke Power's role will be limited to recommending specific improvements, providing direct loans, and inspecting the work.

AVAILABILITY

This program will be available to owners of single or multi-family residential structures served from Duke's retail distribution system with each unit served under a residential rate schedule. Owner shall include homeowner associations of multi-family residential structures. Duke Power Company shall require of homeowner associations adequate assurance of payment in the form of a surety bond or other guarantee agreement approved by Duke Power.

* The residential loan program is being modified to provide direct loans from the established escrow account (rather than loan assistance) at 9.9%.

QUALIFICATION AND IDENTIFICATION OF IMPROVEMENTS

Part I

To qualify for a direct loan of up to $2,500, the owner must agree to upgrade the structure to meet the requirements of Duke's Rate Schedule RC or it Maximum Value Home (The Max) Program installation standards and result in a load management impact. As a result of the required thermal improvements to the structure, an average of 2 kilowatts of electrical load reduction will be realized.

The Company will provide the structure owner with an analysis of necessary improvements upon request. If an owner has been presented an accurate list of improvements by an independent contractor, a second analysis by a Company representative will not be necessary.

Part II

To qualify for a direct loan of up to $1,000, the owner must agree to upgrade the structure by making insulation improvements in the most cost effective manner. The priority of insulation improvements will be determined by the Company by analyzing each structure to determine improvements and the resulting operating cost reduction. Improvements providing the highest return on investment will be conducted first.

The Company will provide the structure owner with a list of insulation improvements in the order of priority of return on investment upon request. If an owner has been presented an accurate list of improvements by an independent contractor, a second analysis by a Company representative will not be necessary. The priority of improvements on the list shall conform to the priority of improvements predetermined by the Company.

PROGRAM ELEMENTS

Specific improvements allowed in the loan can include any items necessary to bring the structure up to the RC rate or Max standards. The range of elements approved for financing include those on the following list:

1. Ceiling/attic insulation
2. Wall insulation
3. Floor insulation
4. Duct insulation
5. Storm windows
6. Storm doors
7. Attic ventilation hardware
8. Caulking, weatherstripping and miscellaneous infiltration reduction measures.
9. Other improvements as may be added from time to time.

CONTRACTOR SELECTION

If requested by the customer at the time of the analysis, the Company representative will furnish a list of qualified contractors willing and able to perform the work outlined in the analysis.

The customer will not be bound by the list of contractors supplied to him and may select a contractor of his choice.

LOAN ARRANGEMENTS

The customer must secure the loan from the local Duke Power Office. Loans to qualifying owners will be made for a period of five years or less at 9.9% APR. If the amount of the loan is less than $1,500 the term of the loan shall not exceed 42 months). The Company may make short term offerings of these loans at less than 9.9% to further encourage the customer to improve the levels of insulation which aids in the reduction of the customer's energy costs.

INSTALLATION VERIFICATION

Upon notification by the owner that the installation is complete, a Duke Power representative will examine the structure to see that it complies with the Qualification and Identification of Improvements Part I or Part II, whichever is applicable.

After the structure owner submits invoices to the company for materials and work performed, the loan to the owner and arrangements for monthly repayment will be initiated by the local business office.

PROGRAM BENEFITS

The benefits to Duke Power will be the reduced need for future additional generation capacity.

A large portion of the homes that will request direct loans have relatively poor insulation levels and are heated by fossil fuels.

With improved levels of insulation the customer will benefit from a reduction in the amount of energy required for space heating and/or cooling.

PROGRAM COST

The revenues required to make direct loans will come from an interest bearing account funded by an added amount on all residential energy sales. The escrow account which funds the Loan Program will not be drawn below the level necessary to satisfy monetary obligations. New commitments to direct loans will be made to the extent allowed by the existing escrow funds.

PURPOSE

The purpose of this program is to provide summer and winter load management benefits to Duke Power by assisting those existing residential customers who could provide meaningful demand reductions by upgrading their home insulation.

PROGRAM

The program provides direct loans not to exceed $2,500 per residential unit to insulate to meet the RC rate or MAX House insulation standards, and provides direct loans not to exceed $1,000 per residential unit to insulate to the most cost effective insulation measure. Duke will make these loans to qualified participants. Monthly payment installments will be billed and repaid through the normal billing and repayment procedures. The combination of loans to an individual owner of multiple residential units may not exceed $50,000. A surety bond or other guarantee agreement approved by Duke Power may be required from multiple residential unit owners.

SCOPE

Loans qualifying under this program will be for specific structure improvements as outlined in the details of this plan. Duke Power's role will be limited to recommending specific improvements, providing direct loans, and inspecting the work.

AVAILABILITY

This program will be available to owners of single or multi-family residential structures served from Duke's retail distribution system with each unit served under a residential rate schedule. Owner shall include homeowner associations of multi-family residential structures. Duke Power Company shall require of homeowner associations adequate assurance of payment in the form of a surety bond or other guarantee agreement approved by Duke Power.

QUALIFICATION AND IDENTIFICATION OF IMPROVEMENTS

Part I

To qualify for a direct loan of up to $2,500, the owner must agree to upgrade the structure so it meets the requirements of Duke's Rate Schedule RC or it Maximum Value Home (The Max) Program insulation standards which results in a load management impact. As a result of the required thermal improvements to the structure, an average of 2 kilowatts of electrical load reduction will be realized.

The Company will provide the structure owner with an analysis of necessary improvements upon request. If an owner has been presented an accurate list of improvements by an independent contractor, a second analysis by a Company representative will not be necessary.

Part II

To qualify for a direct loan of up to $1,000, the owner must agree to upgrade the structure by making insulation improvements in the most cost effective manner. The priority of insulation improvements will be determined, by the Company, through analyzing each structure to determine improvements and the resulting operating cost reduction. Improvements providing the highest return on investment will be conducted first.

The Company will provide the structure owner with a list of insulation improvements in the order of priority of return on investment upon request. If an owner has been presented an accurate list of improvements by an independent contractor, a second analysis by a Company representative will not be necessary. The priority of improvements on the list shall conform to the priority of improvements pre-determined by the Company.

PROGRAM ELEMENTS

Specific improvements allowed in the loan can include any items necessary to bring the structure up to the RC rate or Max standards. The range of elements approved for financing include those on the following list:

1. Ceiling/attic insulation
2. Wall insulation
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9. Other improvements as may be added from time to time.

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If requested by the customer at the time of the analysis, the Company representative will furnish a list of qualified contractors willing and able to perform the work outlined in the analysis.

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INSTALLATION VERIFICATION

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After the structure owner submits invoices to the Company for materials and work performed, the loan to the owner and arrangements for monthly repayment will be initiated by the local business office.

PROGRAM BENEFITS

The benefits to Duke Power will be the reduced need for future additional generation capacity.

A large portion of the homes that will request direct loans have relatively poor insulation levels and are heated by fossil fuels.

With improved levels of insulation the customer will benefit from a reduction in the amount of energy required for space heating and/or cooling.

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SCHEDULE OPT (NC)
OPTIONAL POWER SERVICE, TIME-OF-DAY

AVAILABILITY (North Carolina Only)

Available to the individual customer.

Service under this Schedule shall be used solely by the contracting Customer in a single enterprise, located entirely on a single, contiguous premises.

This Schedule is not available to the individual customer who qualifies for a residential schedule, nor for auxiliary or breakdown service; and power delivered hereunder shall not be used for resale or exchange or in parallel with other electric power, or as a substitute for power contracted for or which may be contracted for, under any other schedule of the Power Company, except at the option of the Company, under special terms and conditions expressed in writing in the contract with the Customer.

The obligations of the Company in regard to supplying power are dependent upon its securing and retaining all necessary rights-of-way, privileges, franchises and permits, for the delivery of such power, and the Company shall not be liable to any customer or applicant for power in the event it is delayed in, or is prevented from furnishing the power by its failure to secure and retain such rights-of-way, rights, privileges, franchises and permits.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts; or
3-phase, 208Y/120 volts, 460Y/265 volts; 480Y/277 volts; or
3-phase, 3-wire, 240, 460, 480, 575, or 2300 volts; or
3-phase, 4160Y/2400, 12470Y/7200, or 24940Y/14400 volts; or
3-phase voltages other than the foregoing, but only at the Company's option, and provided that the size of the Customer's contract warrants a substation solely to serve that Customer, and further provided that the Customer furnish suitable outdoor space on the premises to accommodate a ground-type transformer installation, or substation, or a transformer vault built in accordance with the Company's specifications.

The type of service supplied will depend upon the voltage available. Prospective customers should ascertain the available voltage by inquiry at the nearest office of the Company before purchasing equipment.

Motors of less than 5 H.P. may be single-phase. All motors of more than 5 H.P. must be equipped with starting compensators and all motors of more than 25 H.P. must be of the slip-ring type except that the Company reserves the right, when in its opinion the installation would not be detrimental to the service of the Company, to permit other types of motors.

RATE:

I. Customer Charge per month	$34.31
II. Demand Charge	
A. On-Peak Billing Demand	
1. Summer months of June through September:	
For the first 2000 KW per month	$12.35 per KW
For the next 3000 KW per month	$11.31 per KW
For all over 5000 KW per month	$10.26 per KW
2. Winter months of October through May:	
For the first 2000 KW per month	$ 7.27 per KW
For the next 3000 KW per month	$ 6.22 per KW
For all over 5000 KW per month	$ 5.17 per KW
B. Economy Demand per month	$ .98 per KW
III. Energy Charge	
A. All On-Peak energy per month	4.0658 cents per Kwh
B. All Off-Peak energy per month	2.0345 cents per Kwh

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

The On-Peak period for the summer months of June through September shall be those hours, Monday through Friday, beginning at 12:00 Noon and ending at 10:00 P.M.

The On-Peak period for the winter months of October through May shall be those hours, Monday through Friday, beginning at 6:00 A.M. and ending at 1:00 P.M.

All other weekday hours and all Saturday and Sunday hours shall be Off-Peak.

APPROVED FUEL CHARGE ADJUSTMENTS

The Company's approved fuel charge adjustments, if any, over or under the Rate set forth above pursuant to North Carolina General Statute-62-133.2, will apply to all service supplied under this Schedule. The currently approved adjustments are included in the Rate set forth above.

(Over)

DEFINITION OF "MONTH"

The term "month" as used in this Schedule means the period intervening between meter readings for the purposes of monthly billing, such readings being taken once a month.

Summer months' rates will apply to customers billed for the regular billing months of June through September except that for customers who receive bills on cycle-billing, the summer months' rates will be billed each year beginning with the June billing cycles 15 and 35. Cycle-billing of the summer rates will continue for the remainder of June cycles, all July, August and September cycles, and continue with October billing cycles concluding with October cycles 14 and 34. Winter months' rates apply to all other periods.

CONTRACT DEMAND

The Company will require contracts to specify the maximum demand to be delivered to the Customer which shall be the Contract Demand.

In consideration of special or unusual characteristics of the type of service requested when the Customer can restrict On-Peak demand to levels considerably below that of the Contract Demand, the Company may also contract for a limited On-Peak Contract Demand in addition to the Contract Demand defined above.

DETERMINATION OF BILLING DEMAND

The Demand for billing purposes each month shall be the maximum integrated thirty-minute demand measured relative to the appropriate time period and during the month for which bill is rendered, but:

A. For On-Peak periods, the demand for billing purposes shall not be less than 50% of the Contract Demand or 50% of the On-Peak Contract Demand if such is specified, either of which is less, nor less than 15 kilowatts.

B. For Economy Demand, such maximum monthly measured demand, but not less than 50% of the Contract Demand, shall be compared to the On-Peak Billing Demand and any amount of excess over the On-Peak Billing Demand shall be the Economy Demand for billing purposes.

MINIMUM BILL

The monthly bill shall be no less than the bill calculated on the Rate above including the Customer Charge, Energy Charge, Demand charge, plus other appropriate charges such as Adjustment for Fuel Costs, Extra Facilities Charge, etc., but the Demand Charge component shall be not less than $1.56 per KW per month of Contract Demand. If the Customer's measured demand exceeds the Contract Demand, the Company may at any time establish the minimum based on the maximum integrated demand in the previous twelve months, including the month for which the bill is rendered.

POWER FACTOR CORRECTION

When the average monthly power factor of the Customer's power requirements is less than 85 percent, the Company may correct the integrated demand in kilowatts for that month by multiplying by 85 percent and dividing by the average power factor in percent for that month.

PAYMENT

Bills under this Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the fifteenth day after the date of the bill. If any bill is not so paid, the Company has the right to suspend service. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

Each customer shall enter into a contract to purchase electricity from the Company for a minimum original term of one (1) year, and thereafter from year to year upon the condition that either party can terminate the contract at the end of the original term, or at any time thereafter, by giving at least sixty (60) days' previous notice of such termination in writing; but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

North Carolina Eighth Revised Leaf No. 37
Effective for service on and after July 1, 1990
NCUC Docket No. E-7, Sub 462
Order dated June 26, 1990

(Over)

SCHEDULE OPT (SC)

OPTIONAL POWER SERVICE, TIME-OF-DAY

AVAILABILITY (South Carolina Only)

Available to the individual customer.

Service under this Schedule shall be used solely by the contracting Customer in a single enterprise, located entirely on a single, contiguous premises.

This Schedule is not available to the individual customer who qualifies for a residential schedule, nor for auxiliary or breakdown service; and power delivered hereunder shall not be used for resale or exchange or in parallel with other electric power, or as a substitute for power contracted for or which may be contracted for, under any other schedule of the Power Company, except at the option of the Company, under special terms and conditions expressed in writing in the contract with the Customer.

The obligations of the Company in regard to supplying power are dependent upon its securing and retaining all necessary rights-of-way, privileges, franchises and permits, for the delivery of such power, and the Company shall not be liable to any customer or applicant for power in the event it is delayed in, or is prevented from furnishing the power by its failure to secure and retain such rights-of-way, rights, privileges, franchises and permits.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts; or
3-phase, 208Y/120 volts, 460Y/265 volts; 480Y/277 volts; or
3-phase, 3-wire, 240, 460, 480, 575, or 2300 volts; or
3-phase, 4160Y/2400, 12470Y/7200, or 24940Y/14400 volts; or
3-phase voltages other than the foregoing, but only at the Company's option, and provided that the size of the Customer's contract warrants a substation solely to serve that Customer, and further provided that the Customer furnish suitable outdoor space on the premises to accommodate a ground-type transformer installation, or substation, or a transformer vault built in accordance with the Company's specifications.

The type of service supplied will depend upon the voltage available. Prospective customers should ascertain the available voltage by inquiry at the nearest office of the Company before purchasing equipment.

Motors of less than 5 H.P. may be single-phase. All motors of more than 5 H.P. must be equipped with starting compensators and all motors of more than 25 H.P. must be of the slip-ring type except that the Company reserves the right, when in its opinion the installation would not be detrimental to the service of the Company, to permit other types of motors.

RATE:

I. Customer Charge per month	$33.54
II. Demand Charge	
A. On-Peak Billing Demand	
1. Summer months of June through September:	
For the first 2000 KW per month	$12.45 per KW
For the next 3000 KW per month	$11.04 per KW
For all over 5000 KW per month	$ 8.89 per KW
2. Winter months of October through May:	
For the first 2000 KW per month	$ 7.28 per KW
For the next 3000 KW per month	$ 6.06 per KW
For all over 5000 KW per month	$ 4.49 per KW
B. Economy Demand per month	$ .96 per KW
III. Energy Charge	
A. All On-Peak energy per month	4.7274 cents per Kwh
B. All Off-Peak energy per month	2.3470 cents per Kwh

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

The On-Peak period for the summer months of June through September shall be those hours, Monday through Friday, beginning at 12:00 Noon and ending at 10:00 P.M.

The On-Peak period for the winter months of October through May shall be those hours, Monday through Friday, beginning at 6:00 A.M. and ending at 1:00 P.M.

All other weekday hours and all Saturday and Sunday hours shall be Off-Peak.

ADJUSTMENT FOR FUEL COSTS

The Company's Adjustment for Fuel Costs is incorporated as a part of, and will apply to all service supplied under, this Schedule.

DEFINITION OF "MONTH"

The term "month" as used in this Schedule means the period intervening between meter readings for the purposes of monthly billing, such readings being taken once a month.

Summer months' rates will apply to customers billed for the regular billing months of June through September except that for customers who receive bills on cycle-billing, the summer months' rates will be billed each year beginning with the June billing cycles 15 and 35. Cycle-billing of the summer rates will continue for the remainder of June cycles, all July, August and September cycles, and continue with October billing cycles concluding with October cycles 14 and 34. Winter months' rates apply to all other periods.

(Over)

CONTRACT DEMAND

The Company will require contracts to specify the maximum demand to be delivered to the Customer which shall be the Contract Demand.

In consideration of special or unusual characteristics of the type of service requested when the Customer can restrict On-Peak demand to levels considerably below that of the Contract Demand, the Company may also contract for a limited On-Peak Contract Demand in addition to the Contract Demand defined above.

DETERMINATION OF BILLING DEMAND

The Demand for billing purposes each month shall be the maximum integrated thirty-minute demand measured relative to the appropriate time period and during the month for which bill is rendered, but:

A. For On-Peak periods, the demand for billing purposes shall not be less than 50% of the Contract Demand or 50% of the On-Peak Contract Demand if such is specified, either of which is less, nor less than 15 kilowatts.

B. For Economy Demand, such maximum monthly measured demand, but not less than 50% of the Contract Demand, shall be compared to the On-Peak Billing Demand and any amount of excess over the On-Peak Billing Demand shall be the Economy Demand for billing purposes.

MINIMUM BILL

The monthly bill shall be no less than the bill calculated on the Rate above including the Customer Charge, Energy Charge, Demand charge, plus other appropriate charges such as Adjustment for Fuel Costs, Extra Facilities Charge, etc., but the Demand Charge component shall be not less than $1.43 per KW per month of Contract Demand. If the Customer's measured demand exceeds the Contract Demand, the Company may at any time establish the minimum based on the maximum integrated demand in the previous twelve months, including the month for which the bill is rendered.

POWER FACTOR CORRECTION

When the average monthly power factor of the Customer's power requirements is less than 85 percent, the Company may correct the integrated demand in kilowatts for that month by multiplying by 85 percent and dividing by the average power factor in percent for that month.

PAYMENT

Bills under this Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the fifteenth day after the date of the bill. If any bill is not so paid, the Company has the right to suspend service. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

Each customer shall enter into a contract to purchase electricity from the Company for a minimum original term of one (1) year, and thereafter from year to year upon the condition that either party can terminate the contract at the end of the original term, or at any time thereafter, by giving at least sixty (60) days' previous notice of such termination in writing; but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

South Carolina Eleventh Revised Leaf No. 37
Effective for bills on and after December 1, 1990
SCPSC Docket No. 90-6-E
Order No. 90-1107

(Over)

SCHEDULE RT (NC)
RESIDENTIAL SERVICE, TIME-OF-DAY

AVAILABILITY

Available only on a voluntary basis, at the Company's option, and only to individually-metered residential customers in residences, condominiums, mobile homes, or apartments.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts; or
3-phase, 208Y/120 volts; or other available voltages at the Company's option.

Motors in excess of 2 H.P., frequently started, or arranged for automatic control, must be of a type to take the minimum starting current and must be equipped with controlling devices approved by the Company.

Three-phase service will be supplied, if available. Where three-phase and single-phase service is supplied through the same meter, it will be billed on the rate below. Where three-phase service is supplied through a separate meter, it will be billed on the applicable General Service schedule.

RATE:

I. Customer Charge of $16.78 per month.

II. Plus On-Peak Demand Charge

a. For summer months of June through September:
All KW of On-Peak demand @ $6.19 per KW per month.

b. For winter months of October through May:
All KW of On-Peak demand @ $3.08 per KW per month.

III. Plus Energy Charge

a. All On-Peak energy @ 4.3703 cents per Kwh.
b. All Off-Peak energy @ 3.4199 cents per Kwh.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

The On-Peak period for the summer months of June through September shall be those hours, Monday through Friday, beginning at 1:00 P.M. and ending at 7:00 P.M.

The On-Peak period for the winter months of October through May shall be those hours, Monday through Friday, beginning at 7:00 A.M. and ending at 12:00 Noon.

All other weekday hours and all Saturday and Sunday hours shall be Off-Peak.

APPROVED FUEL CHARGE ADJUSTMENTS

The Company's approved fuel charge adjustments, if any, over or under the Rate set forth above pursuant to North Carolina General Statute 62-133.2, will apply to all service supplied under this Schedule. The currently approved adjustments are included in the Rate set forth above.

DEFINITION OF "MONTH"

The term "month" as used in this Schedule means the period intervening between meter readings for the purposes of monthly billing, such readings being taken once a month.

Summer months' rates will apply to customers billed for the regular billing months of June through September except that for customers who receive bills on cycle-billing, the summer months' rates will be billed each year beginning with the June billing cycles 15 and 35. Cycle-billing of the summer rates will continue for the remainder of June cycles, all July, August and September cycles, and continue with October billing cycles concluding with October cycles 14 and 34. Winter months' rates apply to all other periods.

(Over)

DETERMINATION OF BILLING DEMAND

The demand for billing purposes each month shall be the maximum integrated thirty-minute demand measured for the On-Peak period during the month for which the bill is rendered.

MINIMUM BILL

The minimum bill shall be the Customer Charge.

PAYMENT

Bills under this Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the twenty-fifth day after the date of the bill. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

The original term of this contract shall be one year, and thereafter until terminated by either party on thirty days' written notice.

North Carolina Twenty-Eighth Revised Leaf No. 18
Effective for service on and after July 1, 1990
NCUC Docket No. E-7, Sub 462
Order dated June 26, 1990

(Over)

SCHEDULE RT (SC)

RESIDENTIAL SERVICE, TIME-OF-DAY

AVAILABILITY

Available to individually-metered residential customers in residences, condominiums, mobile homes, or apartments.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts; or
3-phase, 208Y/120 volts; or other available voltages at the Company's option.

Motors in excess of 2 H.P., frequently started, or arranged for automatic control, must be of a type to take the minimum starting current and must be equipped with controlling devices approved by the Company.

Three-phase service will be supplied, if available. Where three-phase and single-phase service is supplied through the same meter, it will be billed on the rate below. Where three-phase service is supplied through a separate meter, it will be billed on the applicable General Service schedule.

RATE:

I. Customer Charge of $13.40 per month.

II. Plus On-Peak Demand Charge

a. For summer months of June through September:
All KW of On-Peak demand @ $6.11 per KW per month.

b. For winter months of October through May:
All KW of On-Peak demand @ $3.06 per KW per month.

III. Plus Energy Charge
a. All On-Peak energy @ 4.8006 cents per Kwh.
b. All Off-Peak energy @ 3.8661 cents per Kwh.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

The On-Peak period for the summer months of June through September shall be those hours, Monday through Friday, beginning at 1:00 P.M. and ending at 7:00 P.M.

The On-Peak period for the winter months of October through May shall be those hours, Monday through Friday, beginning at 7:00 A.M. and ending at 12:00 Noon.

All other weekday hours and all Saturday and Sunday hours shall be Off-Peak.

ADJUSTMENT FOR FUEL COSTS

The Company's Adjustment for Fuel Costs is incorporated as a part of, and will apply to all service supplied under, this Schedule.

DEFINITION OF "MONTH"

The term "month" as used in this Schedule means the period intervening between meter readings for the purposes of monthly billing, such readings being taken once a month.

Summer months' rates will apply to customers billed for the regular billing months of June through September except that for customers who receive bills on cycle-billing, the summer months' rates will be billed each year beginning with the June billing cycles 15 and 35. Cycle-billing of the summer rates will continue for the remainder of June cycles, all July, August and September cycles, and continue with October billing cycles concluding with October cycles 14 and 34. Winter months' rates apply to all other periods.

(Over)

DETERMINATION OF BILLING DEMAND

The demand for billing purposes each month shall be the maximum integrated thirty-minute demand measured for the On-Peak period during the month for which the bill is rendered.

MINIMUM BILL

The minimum bill shall be the Customer Charge.

PAYMENT

Bills under this Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the fifteenth day after the date of the bill. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

The original term of this contract shall be one year, and thereafter until terminated by either party on thirty days' written notice.

South Carolina Thirty-Fourth Revised Leaf No. 18
Effective for bills on and after December 1, 1990
SCPSC Docket No. 90-6-E
Order No. 90-1107

(Over)

SCHEDULE RC (NC)

RESIDENTIAL SERVICE, ENERGY CONSERVATION

AVAILABILITY (North Carolina Only)

Available only to individually-metered residential customers in residences, condominiums, mobile homes, or apartments which meet the thermal conditioning and other requirements in I. below, irrespective of the source of energy for environmental space conditioning.

For individually-metered residential customers in residences, condominiums, mobile homes, or apartments which meet the requirements in I. plus the additional thermal conditioning standards and equipment requirements in II. below, the energy charges per kwh in the Rate will be reduced 2%.

I. Thermal Conditioning and Equipment Standards

A. Sufficient application of thermal control products must be installed to meet the standards outlined below:

Ceilings shall have insulation installed having a thermal resistance value of 30 (R-30).

Walls exposed to full temperature differential (TD) or unconditioned area shall have a total resistance of R-12.

Floors over crawl space shall have insulation installed having a resistance of R-19.

Windows shall be insulated glass or storm windows.

Doors exposed to full TD shall be weatherstripped and equipped with storm doors or of the insulated type. Other doors exposed to unconditioned areas must be weatherstripped.

Air ducts located outside of conditioned space must have: 1) all joints mechanically fastened and sealed, and, 2) a minimum of 2 inches of R-6.5 duct wrap insulation, or its equivalent.

Attic ventilation must be a minimum of one square foot of free area for each 150 square feet of attic area. Mechanical ventilation or ceiling vapor barrier, in lieu of free area, may be used where necessary, subject to special approval.

Chimney flues and fireplaces must have tight-fitting dampers.

Alternate Equivalent Performance Standard: Variations may be made in the Insulation Standards as long as total heat loss does not exceed that calculated using the specific Standards above. Duct or pipe losses shall be included in the computation of total heat losses. Duke Power's procedure for calculating heat loss or the current edition of ASHRAE* Guide shall be the source for heat loss calculations.

Framing corrections are not to be considered in computing resistance values.

All thermal control products described in the Standards above should be installed in accordance with manufacturer's recommendations.

B. Electric Space Heating is not required, but if installed, shall meet the following conditions:

1. Heat pumps shall be controlled by two-stage heating thermostats, the first stage controlling compressor operation and the second stage controlling all auxiliary resistance heaters. Auxiliary heaters shall be limited to 48 amps (11.5 KW at 240 volts) each and shall be switched so that the energizing of each successive heater is controlled by a separate adjustable outdoor thermostat. A manual switch for by-pass of the first stage and the interlock of the second stage of the heating thermostat will be permitted.
2. Excess heating capacity (15% more than total calculated heat losses) may be disconnected at the option of the Company.
3. Total heat loss shall not exceed 30 BTUH*** per square foot of net heated area. Duke Power's procedure for calculating heat loss or the current edition of ASHRAE* Guide shall be the source for heat loss calculations. Duct or pipe losses shall be included in the computation of total heat losses.

C. Electric Domestic Water Heating is not required, but if installed, shall meet the following conditions:

1. Water heaters shall be of the automatic insulated storage type, of not less than 30-gallon capacity, and may be equipped with only a lower element or with a lower element and an upper element.
2. Heaters having only a lower element may have wattages up to but not exceeding the specific wattages as shown below for various tank capacities.

Tank Capacity in Gallons	Maximum Single Element Wattage
30 - 39	3500
40 - 49	4500
50 and larger	5500

3. Heaters having both a lower and an upper element may have wattages in each element up to but not exceeding the specific wattages set forth in the table above for single-element heaters, but they must have interlocking thermostats to prevent simultaneous operation of the two elements; however, if the sum of the wattages of the two elements does not exceed the specific wattages for single-element heaters set forth in the table above, no interlocking device will be required.
4. Heaters of 120 gallons capacity and larger shall be subject to special approval.

II. Additional Thermal Conditioning and Equipment Requirements

If the following requirements are met, the energy charges per kwh in the Rate below will be reduced 2%.

A. Thermal Conditioning Requirements

The structure must meet all of the thermal conditioning requirements in I. A. above plus the following:

Outside walls must be insulated to R-16. Walls between a conditioned area and an unconditioned finished area must be insulated to R-13, except that masonry walls between a conditioned area and a finished unconditioned area must be insulated to R-11.

For concrete slab floors on grade, R-6 perimeter insulation may be used in lieu of the R-19 insulation required for floors over crawl space.

Glass area must not exceed 15% of the square footage of conditioned floor area.

(Over)

AVAILABILITY (continued)

Alternate Equivalent Performance Standard: Variations may be made in the Insulation Standards in II. A. so long as the total heat loss does not exceed that calculated using the specific Standards. Duct or pipe losses shall be included in the computation of total heat losses. Reductions in allowable glass area cannot be used as a basis to lower ceiling, wall or floor insulation levels. Duke Power's procedure for calculating heat loss or the current edition of ASHRAE* Guide shall be the source for heat loss calculations.

Framing correction are not to be considered in computing resistance values.

All thermal control products described in the Standards above should be installed in accordance with manufacturer's recommendations.

B. Electric Heat Pump(s) must be installed to supply all the space conditioning requirements, and in addition to the requirements in I. B. above, heat pumps shall meet the following conditions:

1. The heat pump(s) must have a Seasonal Energy Efficiency Ratio (SEER) of 9 or greater.
2. Perimeter distribution (low outside supply with air directed upward) system is recommended for the level of the structure which is the primary living area.
3. Heat pumps shall be wired for air conditioning load control.

C. Electric Water Heating is required to supply the entire water heating requirements, and in addition to the requirements in I. C. above, water heaters must meet the following condition:

Electric water heaters shall be wired for water heating load control.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts: or
3-phase, 208Y/120 volts; or other available voltages at the Company's option.

Motors in excess of 2 H.P., frequently started, or arranged for automatic control, must be of a type to take the minimum starting current and must be equipped with controlling devices approved by the Company.

RATE:

For the billing months of July through October

$7.54	Basic Facilities Charge
** 6.1327 cents per Kwh for the first	350 Kwh used per month (1)
6.8013 cents per Kwh for all over	350 Kwh used per month (1)

For the billing months of November through June

$7.54	Basic Facilities Charge
** 6.1327 cents per Kwh for the first	350 Kwh used per month (1)
6.1709 cents per Kwh for the next	950 Kwh used per month (1)
5.8873 cents per Kwh for all over	1300 Kwh used per month (1)

(1) For structures which meet the Availability requirements in II. above, the energy charges per kwh will be reduced 2%. The 2% reduction does not apply to the Basic Facilities Charge.

APPROVED FUEL CHARGE ADJUSTMENTS

The Company's approved fuel charge adjustments, if any, over or under the Rate set forth above pursuant to North Carolina General Statute 62-133.2, will apply to all service supplied under this Schedule. The currently approved adjustments are included in the Rate set forth above.

PAYMENT

Bills under this Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the twenty-fifth day after the date of the bill. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

The original term of this contract shall be one year, and thereafter until terminated by either party on thirty days' written notice.

RESIDENTIAL LOAD CONTROL PROVISIONS

In areas where the Company operates load control devices, and at the Company's option, the Company offers a limited program as described in its schedule Rider LC for customers who voluntarily enter into a specific agreement for residential load control whereby the Company will pay customers for the right to interrupt service to the Customer's central electric air conditioning (cooling) systems and/or electric water heaters.

* American Society of Heating, Refrigerating, and Air Conditioning Engineers

** For customers receiving Supplemental Security Income under the program administered by the Social Security Administration and who are blind, disabled, or 65 years of age or over, the rate for the first 350 Kwh shall be 5.6848 cents per Kwh (1). Additional service beyond 350 Kwh per month shall be charged at the regular rates for such service. This is a special experimental rate authorized by the North Carolina Utilities Commission on August 31, 1978. The present maximum discount to customers being served under this experiment is $1.57. Customers' load test data is being obtained to determine if the data confirms this lower charge which was estimated based on a presumed difference in their load characteristics.

*** At 60 degree F. temperature differential

North Carolina Thirty-Seventh Revised Leaf No. 16
Effective for service on and after July 1, 1990
NCUC Docket No. E-7, Sub 462
Order dated June 26, 1990

(Over)

SCHEDULE RC (SC)

RESIDENTIAL SERVICE, ENERGY CONSERVATION

AVAILABILITY (South Carolina Only)

Available only to individually-metered residential customers in residences, condominiums, mobile homes, or apartments which meet the thermal conditioning and other requirements in I. below, irrespective of the source of energy for environmental space conditioning.

For individually-metered residential customers in residences, condominiums, mobile homes, or apartments which meet the requirements in I. plus the additional thermal conditioning standards and equipment requirements in II. below, the energy charges per kwh in the Rate will be reduced 2%.

I. Thermal Conditioning and Equipment Standards

A. Sufficient application of thermal control products must be installed to meet the standards outlined below:

Ceilings shall have insulation installed having a thermal resistance value of 30 (R-30).

Walls exposed to full temperature differential (TD) or unconditioned area shall have a total resistance of R-12.

Floors over crawl space shall have insulation installed having a resistance of R-19.

Windows shall be insulated glass or storm windows.

Doors exposed to full TD shall be weatherstripped and equipped with storm doors or of the insulated type. Other doors exposed to unconditioned areas must be weatherstripped.

Air ducts located outside of conditioned space must have: 1) all joints mechanically fastened and sealed, and, 2) a minimum of 2 inches of R-6.5 duct wrap insulation, or its equivalent.

Attic ventilation must be a minimum of one square foot of free area for each 150 square feet of attic area. Mechanical ventilation or ceiling vapor barrier, in lieu of free area, may be used where necessary, subject to special approval.

Chimney flues and fireplaces must have tight-fitting dampers.

Alternate Equivalent Performance Standard: Variations may be made in the Insulation Standards as long as total heat loss does not exceed that calculated using the specific Standards above. Duct or pipe losses shall be included in the computation of total heat losses. Duke Power's procedure for calculating heat loss or the current edition of ASHRAE* Guide shall be the source for heat loss calculations.

Framing corrections are not to be considered in computing resistance values.

All thermal control products described in the Standards above should be installed in accordance with manufacturer's recommendations.

B. Electric Space Heating is not required, but if installed, shall meet the following conditions:

1. Heat pumps shall be controlled by two-stage heating thermostats, the first stage controlling compressor operation and the second stage controlling all auxiliary resistance heaters. Auxiliary heaters shall be limited to 48 amps (11.5 KW at 240 volts) each and shall be switched so that the energizing of each successive heater is controlled by a separate adjustable outdoor thermostat. A manual switch for by-pass of the first stage and the interlock of the second stage of the heating thermostat will be permitted.
2. Excess heating capacity (15% more than total calculated heat losses) may be disconnected at the option of the Company.
3. Total heat loss shall not exceed 30 BTUH** per square foot of net heated area. Duke Power's procedure for calculating heat loss or the current edition of ASHRAE* Guide shall be the source for heat loss calculations. Duct or pipe losses shall be included in the computation of total heat losses.

C. Electric Domestic Water Heating is not required, but if installed, shall meet the following conditions:

1. Water heaters shall be of the automatic insulated storage type, of not less than 30-gallon capacity, and may be equipped with only a lower element or with a lower element and an upper element.
2. Heaters having only a lower element may have wattages up to but not exceeding the specific wattages as shown below for various tank capacities.

Tank Capacity in Gallons	Maximum Single Element Wattage
30 - 39	3500
40 - 49	4500
50 and larger	5500

3. Heaters having both a lower and an upper element may have wattages in each element up to but not exceeding the specific wattages set forth in the table above for single-element heaters, but they must have interlocking thermostats to prevent simultaneous operation of the two elements; however, if the sum of the wattages of the two elements does not exceed the specific wattages for single-element heaters set forth in the table above, no interlocking device will be required.
4. Heaters of 120 gallons capacity and larger shall be subject to special approval.

II. Additional Thermal Conditioning and Equipment Requirements
If the following requirements are met, the energy charges per kwh in the Rate below will be reduced 2%.

A. Thermal Conditioning Requirements
The structure must meet all of the thermal conditioning requirements in I. A. above plus the following:

Outside walls must be insulated to R-16. Walls between a conditioned area and an unconditioned finished area must be insulated to R-13, except that masonry walls between a conditioned area and a finished unconditioned area must be insulated to R-11.

For concrete slab floors on grade, R-6 perimeter insulation may be used in lieu of the R-19 insulation required for floors over crawl space.

Glass area must not exceed 15% of the square footage of conditioned floor area.

(Over)

AVAILABILITY (continued)

Alternate Equivalent Performance Standard. Variations may be made in the Insulation Standards in II. A. so long as the total heat loss does not exceed that calculated using the specific Standards. Duct or pipe losses shall be included in the computation of total heat losses. Reductions in allowable glass area cannot be used as a basis to lower ceiling, wall or floor insulation levels. Duke Power's procedure for calculating heat loss or the current edition of ASHRAE* Guide shall be the source for heat loss calculations.

Framing correction are not to be considered in computing resistance values.

All thermal control products described in the Standards above should be installed in accordance with manufacturer's recommendations.

B. Electric Heat Pump(s) must be installed to supply all the space conditioning requirements, and in addition to the requirements in I. B. above, heat pumps shall meet the following conditions:

1. The heat pump(s) must have a Seasonal Energy Efficiency Ratio (SEER) of 9 or greater.
2. Perimeter distribution (low outside supply with air directed upward) system is recommended for the level of the structure which is the primary living area.
3. Heat pumps shall be wired for air conditioning load control.

C. Electric Water Heating is required to supply the entire water heating requirements, and in addition to the requirements in I. C. above, water heaters must meet the following condition:

Electric water heaters shall be wired for water heating load control.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts; or
3-phase, 208Y/120 volts; or other available voltages at the Company's option.

Motors in excess of 2 H.P., frequently started, or arranged for automatic control, must be of a type to take the minimum starting current and must be equipped with controlling devices approved by the Company.

RATE:

$6.16	Basic Facilities Charge
6.0655 cents per Kwh for the first	1000 Kwh used per month (1)
6.6610 cents per Kwh for all over	1000 Kwh used per month (1)

(1) For structures which meet the Availability requirements in II. above, the energy charges per kwh will be reduced 2%. The 2% reduction does not apply to the Basic Facilities Charge.

ADJUSTMENT FOR FUEL COSTS

The Company's Adjustment for Fuel Costs is incorporated as a part of, and will apply to all service supplied under, this Schedule.

PAYMENT

Bills under this Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the fifteenth day after the date of the bill. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

The original term of this contract shall be one year, and thereafter until terminated by either party on thirty days' written notice.

RESIDENTIAL LOAD CONTROL PROVISIONS

In areas where the Company operates load control devices, and at the Company's option, the Company offers a limited program as described in its schedule Rider LC for customers who voluntarily enter into a specific agreement for residential load control whereby the Company will pay customers for the right to interrupt service to the Customer's central electric air conditioning (cooling) systems and/or electric water heaters.

* American Society of Heating, Refrigerating, and Air Conditioning Engineers

** At 60 degree F. temperature differential

South Carolina Thirty-Ninth Revised Leaf No. 16
Effective for bills on and after December 1, 1990
SCPSC Docket No. 90-6-E
Order No. 90-1107

(Over)

RIDER LC (NC)
RESIDENTIAL LOAD CONTROL

Available to individually metered residential customers receiving concurrent service from the Company on Schedule R, RA, or RC. Water heating load control on this Rider is not available if the residence receives water heating service on Schedule WC.

In areas where the Company operates load control devices, customers may, on a limited basis, voluntarily enter into a specific agreement for residential load control, at the Company's option; in addition to all other requirements of the applicable schedule, the following provisions shall apply:

1. General Provisions

Categories of Load Control
Customers may request water heating and air conditioning loads be controlled under the same category or different categories, at the Customer's option.

Category A.
Emergency Control: The Company shall have the right to interrupt service to the Customer's central air conditioning (cooling) systems and/or electric water heaters. This interruption of service may be at any time the Company has capacity problems, and the Company reserves the right to test the functioning of these load control provisions at any time.

Category B.
Emergency Control plus Cycling Control: For all loads controlled under this category, the Company shall have the right to interrupt service as described in Category A above, and in addition shall have the right to intermittently interrupt (cycle) service to the Customer's central electric air conditioning (cooling) systems and/or electric water heaters. The Company will restrict its operation of the load control devices so that during the eighteen (18) hour period from 6 a.m. until 12 midnight the total duration of cycling interruption for each type of load shall not exceed nine (9) hours. During all other hours, the Company will not operate the load control devices for load cycling. No individual interruption due to cycling of service to water heaters shall exceed four (4) hours in duration. No individual interruption due to cycling of service to air conditioning systems shall exceed thirty (30) minutes during a sixty (60) minute period. The Company reserves the right to test the functioning of these provisions at any time.

An electric water heater may be controlled provided it is of the automatic insulated storage type, of not less than 30-gallon capacity (not less than 15-gallon capacity on Schedule R) and is installed and used without alternative system assistance.

The Company shall have the right to require that the owner of the controlled equipment give satisfactory written approval for the Company's installation and operation of load control devices on that equipment before entering an agreement with the Customer and making such installation.

2. Credits for Load Control

A payment for controlled water heating will be made to the Customer as a billing credit as follows:

Category A, \$2.00/month
or, Category B, \$2.50/month

A payment for controlled air conditioning will be made to the Customer in each of the four billing months of July through October as a billing credit as shown below per month per KW of full-load nameplate compressor capacity. Credit payments will be made only for the first 4 KW per 1,000 square feet of conditioned space:

<u>For the four (4) billing months, July through October</u>

Category A, \$3.25 per month, per KW
or, Category B, \$3.50 per month, per KW

The total credits on any monthly bill shall not exceed 35% of the current monthly bill as calculated on the applicable schedule exclusive of such credits, nor shall the monthly bill be less than the Basic Facilities Charge for the applicable Schedule

(Over)

3. Installation Fee

Where there exists, or the Customer provides, a water heater circuit and/or air conditioner circuit, wired through a Company meter enclosure, exclusive of any other load, and suitable for the installation of a load control device, there shall be no installation charge.

Where additional wiring is required for the installation of load control devices and the Company determines that it can accomplish this in a manner which is economically feasible, the Customer shall pay a fee as follows:

For installation of the load control devices for only water heating load or only air conditioning load, the fee shall be $35.00.

For concurrent installation of the control devices for both water heating load and air conditioning load, the fee shall be $50.00.

4. Contract Period

The Company offers a contract for customers allowing load control for an initial term of two years, and thereafter until terminated by either party on thirty days' written notice. If within the first year, the Customer wishes to discontinue any load control service but continue service at the same location, the Customer will pay a $25.00 service charge; or, at the Company's option, if the Customer contracts for another type of control which can utilize the existing equipment, there will be no such charge. The Customer may terminate the contract after the first year without such service charge.

North Carolina Second Revised Leaf No. 70
Effective for service on and after August 28, 1984
NCUC Docket No. E-7, Sub 338
Order dated August 28, 1984

(Over)

RIDER LC (SC)
RESIDENTIAL LOAD CONTROL

Available to residential customers receiving concurrent service from the Company on Schedules R, RW, RA, or RC.

In areas where the Company operates load control devices, customers may enter into a specific agreement for residential load control, at the Company's option, on a limited and voluntary basis; in addition to all other requirements of the applicable schedule, the following provisions shall apply:

1. General Provisions

   The Company shall have the right to interrupt service to the Customer's central electric air conditioning (cooling) systems and/or electric water heaters. This interruption of service may be at any time the Company has capacity problems and the Company reserves the right to test the functioning of these load control provisions at any time.

   An electric water heater may be controlled provided it is of the automatic insulated storage type, of not less than 30 gallon capacity (not less than 15 gallon capacity on Schedule R) and is installed and used without alternate system assistance.

   The Company shall have the right to require that the owner of the controlled equipment give satisfactory written approval for the Company's installation and operation of load control devices on that equipment before entering an agreement with the Customer and making such installation.

2. Credits for Load Control

   A payment for water heater control will be made to the Customer as a billing credit of $2.00 per month.

   A payment for air conditioner control will be made to the Customer in each of the four billing months of July through October at the rate of $3.25 per month per KW of full-load nameplate compressor capacity for the first 4 KW per 1,000 square feet of conditioned space.

   The total credits on any monthly bill shall not exceed 35% of the current monthly bill as calculated on the applicable schedule exclusive of such credits, nor shall the monthly bill be less than the Basic Facilities Charge.

3. *Installation* Fee

   Where there exists, or the Customer provides, a water heater circuit and/or air conditioner circuit, wired through a Company meter enclosure, exclusive of any other load, and suitable for the installation of a load control device, there shall be no installation charge.

   Where additional wiring is required for the installation of load control devices and the Company determines that it can accomplish this in a manner which is economically feasible, the Customer shall pay a fee as follows:

   For installation of the control devices for only water heating load, or only air conditioning load, the fee shall be $35.00.

   For concurrent installation of the control devices for both water heating load and air conditioning load, the fee shall be $50.00.

4. Contract Period

   The Company offers a contract for customers allowing load control for an initial term of two years, and thereafter until terminated by either party on thirty days' written notice. If within the first year, the Customer wishes to discontinue load control service but continue service at the same location, the Customer will pay a $25.00 service charge; the Customer may terminate after the first year without such service charge.

South Carolina First Revised Leaf No. 70
Effective for bills rendered on and after November 5, 1981
SCPSC Docket No. 81-300-E, Order No. 81-739

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RIDER IS (NC)
INTERRUPTIBLE POWER SERVICE

Available to non-residential customers receiving concurrent service from the Company on Schedules G, GA, I, IP, GT, IT, or OPT.

For non-residential customers who enter into a specific contract for interruptible power service, the following provisions apply in addition to the stated provisions of the Customer's rate schedule:

1. Load Limitations:

   Contracts for interruptible power service will be accepted by the Company on the basis of successive contracts, and each contract shall specify an interruptible, integrated demand of not more than 30,000 KW to be subject to these provisions. The Company shall limit the acceptance of contracts to a total of 100,000 KW of total system interruptible load on all non-residential schedules. Future contracts providing for replacement loads will be considered in order to maintain the availability of 100,000 KW capacity to the Company.

2. Definitions:

   Contract Demand: The Contract Demand is the maximum kilowatt demand which the Company shall be required to supply to the Customer, and is the sum of the Interruptible Contract Demand with limited periods of availability, and the Firm Contract Demand with an unlimited period of availability.

   Interruptible Contract Demand: The Interruptible Contract Demand of not more than 30,000 KW is that portion of the Contract Demand which the Company will supply to the Customer at all times except during Interruption Periods.

   Firm Contract Demand: The Firm Contract Demand, which may be specified at different values for the summer months of June through September and the winter months of October through May, is that portion of the Contract Demand which the Company will supply to the Customer without limitation on the periods of availability.

   Interruption Period: An Interruption Period is that interval of time, initiated and terminated by the Company, during which the Customer will require service at no more than the Firm Contract Demand and the Company is obligated to supply no more than the Firm Contract Demand.

   Penalty Demand: The Penalty Demand is the maximum thirty (30) minute integrated demand required by the Customer during an Interruption Period in excess of the Firm Contract Demand.

   Exposure Period: The Exposure Period is that period of time within the month corresponding to the weekday peak demand periods and during which interruption under these provisions is most likely to occur. Specifically, the Exposure Period for the purpose of computing monthly credits is defined as follows:

   Summer Months of June through September —
   12 Noon to 10 P.M., Monday through Friday

   Winter Months of October through May —
   6 A.M. to 1 P.M., Monday through Friday

3. Control Notices:

   The Customer shall be notified of all initiations of Interruption Periods at least thirty (30) minutes prior to such times, and the Customer shall fully comply with the Company's requests to reduce and maintain his load to not more than the Firm Contract Demand for the duration of the Interruption Period. The Customer shall be notified of all terminations of Interruption Periods.

4. Interruptible Power Categories:

   The Customer shall specify the availability of his interruptible load by selecting one of the following categories:

Interruptible Power Category	Maximum Annual Hours of Interruption	Maximum Hours of Interruption in Five (5) Years
1	200	750
2	400	1500
3	600	2250

   The Company may invoke interruption periods for not more than the number of hours so designated. Further, the Company shall have the right to invoke an interruption period at any time, subject to a maximum duration of 15 hours in any calendar weekday, which may be extended only by mutual agreement with the Customer.

5. Credit and Credit Computation:

   Each month, a determination of the interruptible capacity available to the Company will be made in order to compute a credit. All energy consumed at a level above the Firm Contract Demand, but not exceeding the Contract Demand, during the Exposure Period, excluding the energy consumed above the Firm Contract Demand during Interruption Periods, will be divided by the hours of duration of the Exposure Period excluding the hours of duration of Interruption Periods. The value thus computed will be reduced by the amount of the monthly maximum demand above the Firm Contract Demand which occurs during any Interruption Period. The resulting amount will be the Effective Interruptible Demand (EID) and shall not be less than zero.

(Over)

5. Credit and Credit Computation: (Continued)

The formula for computation is:

$$EID = \frac{KWH_{EP} - KWH_{IP}}{Hours_{EP} - Hours_{IP}} - KW_{MP}$$

Where: EID = Effective Interruptible Demand

KWH_{EP} = Energy consumed during the Exposure Period above Firm Contract Demand, but not exceeding Contract Demand

KWH_{IP} = Energy consumed during Interruption Periods above Firm Contract Demand

$Hours_{EP}$ = Hours of duration of the Exposure Period

$Hours_{IP}$ = Hours of duration of the Interruption Periods

KW_{MP} = Maximum monthly Penalty Demand

The amount of credit to be applied to the Customer's account each month will be determined by the formula:

$$Credit = EID \times \$/KW_{EID}$$

Where: $\$/KW_{EID}$ is a value from the following table:

Interruptible Power Category	$\$/KW_{EID}$
1	\$1.15
2	\$1.75
3	\$2.05

6. Penalty and Penalty Computation:

Should the Customer fail to reduce and maintain his load at, or below, the Firm Contract Demand during any Interruption Period, a penalty will be applied to the Customer's account for the month of occurrence. The penalty shall be computed by the formula:

$$Penalty = \Sigma KW_P \times \$1.58$$

Where: ΣKW_P = the summation of the Penalty Demands occurring in each and every Interruption Period during the billing period.

7. A monthly "Extra Facilities Charge," equal to 1.7% of the installed cost of the extra facilities necessary for interruptible power service, but not less than $25, shall be billed to the Customer in addition to the billing for energy, or for demand plus energy, in accordance with the Extra Facilities provisions of the Company's Service Regulations.

8. Contract Period:

Contracts with interruptible load provisions shall be for a minimum original term of five (5) years and thereafter until terminated, by giving at least thirty (30) months' previous notice of such termination in writing, but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

The Company reserves the right to terminate the Customer's contract containing the interruptible load provisions at any time upon written notice to the Customer in the event that the Customer violates any of the terms or conditions of the applicable schedule or this Rider. In the event of early termination of a contract with interruptible load provisions, the Customer will be required to pay the Company for the costs due to such early cancellation.

North Carolina Second Revised Leaf No. 72
Effective for service on and after October 31, 1986
NCUC Docket No. E-7, Sub 408
Order dated October 31, 1986

(Over)

RIDER IS (SC)
INTERRUPTIBLE POWER SERVICE

Available to non-residential customers receiving concurrent service from the Company on Schedules G, GA, I, SP, GT, IT, OPT, or PG.

For non-residential customers who enter into a specific contract for interruptible power service, the following provisions apply in addition to the stated provisions of the Customer's rate schedule:

1. Load Limitations:

   Contracts for interruptible power service will be accepted by the Company on the basis of successive contracts, and each contract shall specify an interruptible, integrated demand of not more than 30,000 KW to be subject to these provisions. The Company shall limit the acceptance of contracts to a total of 200,000 KW of total system interruptible load on all non-residential schedules. Future contracts providing for replacement loads will be considered in order to maintain the availability of 200,000 KW capacity to the Company.

   At the option of the Company, Customers may specify that the interruptible load provisions of this Rider be applicable only to a designated portion of the Customer's load which shall be submetered for purposes of this Rider.

2. Definitions:

   Contract Demand: The Contract Demand is the maximum kilowatt demand which the Company shall be required to supply to the Customer.

   Interruptible Contract Demand: The Interruptible Contract Demand of not more than 30,000 KW is that portion of the Contract Demand which the Company will supply to the Customer at all times except during Interruption Periods.

   Firm Contract Demand: The Firm Contract Demand, which may be specified at different values for the summer months of June through September and the winter months of October through May, is that portion of the Contract Demand which the Company will supply to the Customer without limitation on the periods of availability.

   Interruption Period: An Interruption Period is that interval of time, initiated and terminated by the Company, during which the Customer will require service at no more than the Firm Contract Demand and the Company is obligated to supply no more than the Firm Contract Demand.

   Penalty Demand: The Penalty Demand is the maximum thirty (30) minute integrated demand required by the Customer during an Interruption Period in excess of the Firm Contract Demand.

   Exposure Period: The Exposure Period is that period of time within the month corresponding to the weekday peak demand periods and during which interruption under these provisions is most likely to occur. Specifically, the Exposure Period for the purpose of computing monthly credits is defined as follows:

   Summer Months of June through September —
   12 Noon to 10 P.M., Monday through Friday

   Winter Months of October through May —
   6 A.M. to 1 P.M., Monday through Friday

3. Control Notices and Limitations:

   The Customer shall be notified of all initiations of Interruption Periods at least thirty (30) minutes prior to such times, and the Customer shall fully comply with the Company's requests to reduce and maintain his load to not more than the Firm Contract Demand for the duration of the Interruption Period. The Customer shall be notified of all terminations of Interruption Periods.

   The Company may invoke interruption periods for not more than 150 hours in any year. Further, the Company shall have the right to invoke an interruption period at any time, subject to a maximum duration of 10 hours in any calendar day, which may be extended only by mutual agreement with the Customer.

4. Credit and Credit Computation:

   Each month, a determination of the interruptible capacity available to the Company will be made in order to compute a credit. All energy consumed at a level above the Firm Contract Demand during the Exposure Period, excluding the energy consumed above the Firm Contract Demand during Interruption Periods, will be divided by the hours of duration of the Exposure Period excluding the hours of duration of Interruption Periods. The value thus computed will be reduced by the amount of the monthly maximum demand above the Firm Contract Demand which occurs during any Interruption Period. The resulting amount will be the Effective Interruptible Demand (EID) and shall not be less than zero.

   The formula for computation is:

$$EID = \frac{KWH_{EP} - KWH_{IP}}{Hours_{EP} - Hours_{IP}} - KW_{MP}$$

   Where: EID = Effective Interruptible Demand

   KWH_{EP} = Energy consumed during the Exposure Period above Firm Contract Demand

   KWH_{IP} = Energy consumed during Interruption Periods above Firm Contract Demand

   $Hours_{EP}$ = Hours of duration of the Exposure Period

   $Hours_{IP}$ = Hours of duration of the Interruption Periods

   KW_{MP} = Maximum monthly Penalty Demand

   The amount of credit to be applied to the Customer's account each month will be determined by the formula:

   Credit = EID × $\$3.50/KW_{EID}$

(Over)

5. Penalty and Penalty Computation:

   Should the Customer fail to reduce and maintain his load at, or below, the Firm-Contract Demand during any Interruption Period, a penalty will be applied to the Customer's account for the month of occurrence. The penalty shall be computed by the formula:

   $$\text{Penalty} = \Sigma KW_p \times \$1.58$$

   Where: ΣKW_p = the summation of the Penalty Demands occurring in each and every Interruption Period during the billing period.

6. A monthly "Extra Facilities Charge," equal to 1.7% of the installed cost of the extra facilities necessary for interruptible power service, but not less than $25, shall be billed to the Customer in addition to the billing for energy, or for demand plus energy, in accordance with the Extra Facilities provisions of the Company's Service Regulations.

7. Contract Period:

   Contracts with interruptible load provisions shall be for a minimum original term of five (5) years and thereafter until terminated, by giving at least twelve (12) months' previous notice of such termination in writing, but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

   The Company reserves the right to terminate the Customer's contract containing the interruptible load provisions at any time upon written notice to the Customer in the event that the Customer violates any of the terms or conditions of the applicable schedule or this Rider. In the event of early termination of a contract with interruptible load provisions, the Customer will be required to pay the Company for the costs due to such early cancellation.

South Carolina Third Revised Leaf No. 72
Effective for bills rendered on and after March 5, 1989
SCPSC Docket No. 89-63-E, Order No. 89-114

(Over)

RIDER SG (NC)
STANDBY GENERATOR CONTROL

Available at the option of the Company to non-residential customers receiving concurrent service from the Company.

For customers not receiving concurrent service from the Company on Rider IS who enter into a specific contract for the control of standby generators which are not operated in parallel with the Company's system, the following provisions shall apply:

1. GENERAL DESCRIPTION

The Standby Generator Control Program is designed to provide a source of capacity through load reduction at any time the Company has capacity problems. The Company reserves the right to test the operation of the Customer's standby generator(s) at any time. When the Company requests the operation of the standby generators, the watt-hour meter(s) installed on or near the generator bus of the Customer's facility will be energized to record the KWH output of the generator. Each month the meter(s) will be read and the Customer compensated for the KWH output based on a credit amount per KWH which will be up-dated monthly. Payments will not be rendered unless the Company requested the generator operation and the Customer complied.

2. METERING AND CONTROL EQUIPMENT

The metering and control equipment will be furnished, owned, installed and maintained by the Company at no expense to the Customer.

3. DEFINITIONS

Engine/Generator Nameplate Rating: The nameplate rating is the maximum kilowatt output of the engine/generator at full load at its rated power factor as specified on the nameplate.

Control Period: A control period is that interval of time, initiated and terminated by the Company, during which the Customer is requested to transfer load from the Company's source to the electrical distribution system supplied by the engine/generator unit.

Notice to Control Load: The Customer shall be notified by remote signal of all initiations of Control Periods at least (10) minutes prior to such times.

4. METER READING

Each month, the installed watt-hour meter(s) shall be read for purposes of computing a payment. In the event that a Control Period is in progress, the reading of the meter(s) shall be delayed until after the Control Period has ended.

5. EQUIPMENT INSPECTION

At periodic intervals, the Company will inspect each generator metering and control system installation at the Customer's facility.

6. BASIS OF MONTHLY CREDIT

Each month, a credit will be computed in accordance with fuel oil price quotations from vendors for Company stations with combustion turbines.

7. MONTHLY CREDIT NOTIFICATION

Notification of the credit per KWH and the monthly period for which it is applicable shall be provided to each participating Customer no later than the last business day of the month preceding the application period.

8. COMPUTATION OF THE MONTHLY PAYMENT

Following the reading of the standby generator meter(s) each month, the amount of monthly payment for each participating Customer shall be computed as follows:

MONTHLY PAYMENT (\$) = (KWH × \$/KWH) + \$10.00 per month for compliance

Where: KWH = Total KWH output of Customer's standby generator during the monthly Control Periods

\$/KWH = Applicable credit for the month

The \$10.0 per month for compliance is in addition to the credit per KWH and is paid only in months in which the Company requests operation of the generator and the Customer complies.

In no event shall the monthly payment be based on an amount of KWH greater than the generator nameplate rating in KW multiplied by the Control Period hours during the month.

9. PAYMENT TO CUSTOMER

Each month, payment shall be made by check to each participating Customer for the amount of credit due for the previous month. The check (or attached statement) shall specify at least the following information and other data as appropriate: Applicable Month, Total KWH Output, Credit Amount, and Payment Amount.

North Carolina First Revised Leaf No. 74
Effective February 5, 1986
NCUC Docket No. E-7, Sub 405
Order dated February 5, 1986

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RIDER SG (SC)
STANDBY GENERATOR CONTROL

Available at the option of the Company to non-residential customers receiving concurrent service from the Company.

For customers not receiving concurrent service from the Company on Rider IS who enter into a specific contract for the control of standby generators which are not operated in parallel with the Company's system, the following provisions shall apply:

1. GENERAL DESCRIPTION

The Standby Generator Control Program is designed to provide a source of capacity through load reduction at any time the Company has capacity problems. The Company reserves the right to test the operation of the Customer's standby generator(s) at any time. When the Company requests the operation of the standby generators, the watt-hour meter(s) installed on or near the generator bus of the Customer's facility will be energized to record the KWH output at the generator. Customers may voluntarily enter into an agreement to participate in Standby Generator Control in one of the following categories:

Category A.

Standard Generator Response: The Customers under Category A shall operate their generators on an "as available" basis. Each month the meter(s) will be read and the Customer compensated for the KWH output based on an energy credit which will be updated monthly.

Category B.

Guaranteed Generator Response: The Customers under Category B shall operate their generators on a "guaranteed response" basis. Customers shall commit to operate during a minimum of 80% of the Control periods annually, including tests, and to provide at least 200 KW average capacity on an annual basis. Each month the meter(s) will be read. The Customer under Category B will receive a capacity credit based on the average capacity generated during all control periods of the current month. Also, the Customer will be compensated for the KWH output based on an energy credit which will be updated monthly. Continuation under Category B will be based on the Company's annual review of its records for the particular customer's standby generation to determine when actual performance has indicated compliance with the above standards for the twelve-month period.

Payments will not be rendered unless the Company requested the generator operation and the Customer complied.

2. METERING AND CONTROL EQUIPMENT

The metering and control equipment will be furnished, owned, installed and maintained by the Company at no expense to the Customer.

3. DEFINITIONS

Engine/Generator Nameplate Rating: The nameplate rating is the maximum kilowatt output of the engine/generator at full load at its rated power factor as specified on the nameplate.

Control Period: A control period is that interval of time, initiated and terminated by the Company, during which the Customer is requested to transfer load from the Company's source to the electrical distribution system supplied by the engine/generator unit. No control period shall be of more than ten (10) hours duration in any calendar day.

Notice to Control Load: The Customer shall be notified by remote signal of all initiations of Control Periods at least (10) minutes prior to such times.

4. METER READING

Each month, the installed watt-hour meter(s) shall be read for purposes of computing a payment. In the event that a Control Period is in progress, the reading of the meter(s) shall be delayed until after the Control Period has ended.

5. EQUIPMENT INSPECTION

At periodic intervals, the Company will inspect each generator metering and control system installation at the Customer's facility.

6. BASIS OF MONTHLY CREDIT

Each month, an energy credit will be computed in accordance with fuel oil price quotations from vendors for Company stations with combustion turbines.

7. MONTHLY CREDIT NOTIFICATION

Notification of the energy credit per KWH and the monthly period for which it is applicable shall be provided to each participating Customer no later than the last business day of the month preceding the application period.

(Over)

8. COMPUTATION OF THE MONTHLY PAYMENT

Following the reading of the standby generator meter(s) each month, the amount of monthly payment for each participating Customer shall be computed as follows:

ENERGY CREDITS (Categories A & B)

Monthly Payments ($) = (KWH × $/KWH) + $10.00 per month for compliance

CAPACITY CREDITS (Category B Only)

For Category B customers, a Capacity Credit will be computed as follows:

Monthly Payments ($) = (KWH/Total Hours in Control Periods) × $/KW

Where: KWH = Total KWH output of Customer's standby generator during the monthly Control Periods

$/KWH = Applicable energy credit for the month

$/KW = $2.75 Applicable capacity credit

The $10.00 per month for compliance is in addition to the credit per KWH and is paid only in months in which the Company requests operation of the generator and the Customer complies.

In no event shall the monthly payment be based on an amount of KWH greater than the generator nameplate rating in KW multiplied by the Control Period hours during the month.

9. PAYMENT TO CUSTOMER

Each month, payment shall be made by check to each participating Customer for the amount of credit due for the previous month. The check (or attached statement) shall specify at least the following information and other data as appropriate: Applicable Month, Total KWH Output, Credit Amount, and Payment Amount.

South Carolina Second Revised Leaf No. 74
Effective for bills rendered on and after March 5, 1989
SCPSC Docket No. 89-63-E, Order No. 89-114

(Over)

Appendix VI-3: Pilot Projects

INTRODUCTION:

Demand-side options, like other resource options, have uncertainties associated with their capability to meet utility system requirements. These factors consist of both technical and non-technical issues. The non-technical issues include customer preference and behavior, the effectiveness of program marketing/distribution channels and program costs. The technical issues include system load shape impacts, training for Duke personnel, and additional metering or communications equipment needed.

Pilot projects are undertaken to address the factors of uncertainty associated with demand side options. Pilot projects involve the introduction of an option into the marketplace in some limited fashion to gauge the impact in a controlled environment. The results of this test are used to determine whether the option needs to be redesigned or re-evaluated. Work Teams are formed with representatives from various departments to develop the specifics of the Pilot Projects.

The Departments involved in the Pilot Projects and their contributions to the development and implementation of the pilots are discussed in VI-3.1 of this appendix..

The eleven options that are currently being piloted are listed in Table 1. The option development team determined that these should piloted to address various uncertainties before they could be introduced to the marketplace as a full program. The pilot details with the unknowns to be investigated under each pilot is found in VI-3.2 of this appendix.

Table 1: 1992 Demand Side Pilot Projects

PILOT	OBJECTIVES	MILESTONES	
I. Residential Pilots			
A. High Efficiency Lighting	To test customer acceptance of compact fluorescent bulbs, target market response, and the feasibility of using a fulfillment house as distribution tool.	Res. - Comp Design - Comp	Implem - Comp Eval. - 2/92
B. High Efficiency Ground Coupled Heat Pump	To encourage the installation of ground coupled heat pumps on the Duke system. Installation costs, market potential, and load shapes will be determined.	Res. - Comp Design - Comp	Implem - 4/92 Eval. - 2/93
C. HVAC Tune-Up	To investigate the demand and energy reductions associated with repairing A/C and heat pump systems that are experiencing operational problems.	Res. - 2/92 Design - 2/92	Implem - 3/92 Eval. - 2/93
D. Water Heater Insulating Blanket	To promote the installation of water heater blankets, reducing the losses associated with lower levels of insulation.	Res. - Comp Design - Comp	Implem - 2/92 Eval. - 3/92
II. Commercial/Industrial Pilot			
A. Non-Residential Air Conditioning Load Shift (Cool Storage)	To promote cool storage technologies in the Duke service area. Customer economics and load shape data will be collected.	Res. - Comp Design - Comp	Implem - 4/92 Eval. - 2/93
B. Non-Residential Heat Treating Load Shift	To investigate the potential for convincing customers to shift heat treating process loads to off peak hours.	Res. - Comp Design - Comp	Implem - Comp Eval. - Comp
C. Industrial High Efficiency Dust Collection	To investigate the potential for convincing furniture manufacturers to install hi-efficiency dust collection systems for demand and energy reductions.	Res. - Comp Design - Comp	Implem - Comp Eval. - Comp
D. Non-Residential High Efficiency Indoor Lighting	To determine the feasibility of a full scale program convincing the installation of hi-efficiency indoor lighting technology in the commercial/industrial markets.	Res. - 3/92 Design - 4/92	Implem - 2/94 Eval. - 4/94
E. Motor Systems	To improve the efficiency and effectiveness of motors in meeting specific end-use applications.	Res. - 4/92 Design - TBD	Implem - TBD Eval. - TBD
F. Non-Residential Air Conditioning Load Control	To evaluate the operating characteristics and customer acceptance of an interruptible program for non-residential air conditioning systems.	Res. - Comp Design - Comp	Implem - Comp Eval. - 2/92
G. Standby Generator With Backfeed	To evaluate the technical feasibility of allowing parallel connections of customer owned generation to the Duke Power system.	Res. - Comp Design - Comp	Implem - Comp Eval. - Comp

Res - Research; Implem - Implementation; Eval - Evaluation; Comp - Completed
The milestones reflect the quarter and year of phase completion.

Appendix VI-3.1: Pilot Project Work Teams

Work Teams are formed once an option has been identified as having uncertainties that need addressing. Work Teams take the uncertainties identified and develop a program that will answer the questions that the uncertainties pose. The members bring to the Team the expertise and perspective that will make the project a well-rounded effort.

Table 2 identifies the core departments that make up the Work Teams and the expertise they contribute to the development of the pilots. Other departments are called upon to assist in the development of the project as the need arises but their involvement is normally minimal.

Table 2: PILOT WORK TEAM INVOLVEMENT

Department	Contribution
Customer Studies	• Provide Market Research expertise • Provide target market and customer survey data
Demand Side Planning	• Provide input to the pilot as to the assumptions and data used in the development of the original Demand Side option • Assist in the formation of the pilot scope and objectives • Analyze data collected from the pilot for inclusion back into the modelling process • Assist in the evaluation of the pilot for a full program
Field Marketing (Power and Residential)	• Provide technical support • Coordinate field communication • Provide field training and assistance
Marketing Program Development	• Develop the marketing strategy for implementing the pilot • Administer the implementation of the pilot • Provide training for the field on the pilot • Assist in the evaluation of the pilot for a full program
Other Departments: - Power Delivery - Rates - Customer Service Center - Customer Accounting External Groups: - Alternative Energy Corporation (AEC)	• Provide technical assistance • Coordinate field assistance and communications

Appendix VI-3.2: Pilot Descriptions

Residential Pilot Projects

PILOT: High Efficiency Ground Coupled Heat Pump (Geothermal)

Purpose

The purpose of this pilot is to encourage the installation of high efficiency ground coupled heat pumps to reduce demand impact on the generation system while improving customer comfort. The pilot will determine typical installation costs, market potential, and load shape data.

Background/Assumptions

Ground Coupled (Geothermal) Heat Pumps have been identified as an extremely efficient means of both heating and cooling by both the National Rural Electric Cooperative Association (NRECA) and the Department of Energy (DOE). This heat pump technology uses the relatively constant temperature of the earth as both a heat source and heat sink for its operation.

Geothermal heat pumps install, either horizontally or vertically, a closed loop heat exchanger in the earth to either pick up heat for space conditioning in the winter or to discharge excess space heat in the summer. By relying on a non-weather responsive source, the efficiencies of the heat pump technology are greater than that of the standard air source technology.

Although a fairly well known and widely utilized technology in other areas of the country, the geothermal heat pump is not greatly understood or used in the Duke service area. One of the obstacles to its acceptance is the premium on the installation costs due to the additional piping and trenching for the ground loop. One of the main objectives of the pilot is to determine the most effective method of encouraging the customer to install the geothermal heat pump.

This pilot was passed through the integration process as an option with the 1990 plan.

Objectives

1. Determine typical installation costs and cost effectiveness of the incentive.
2. Determine Market acceptance and potential.
3. Install metering on pilot locations to determine operating costs of the system and obtain load shape data.
4. Evaluate the data for feasibility of a full program.

Implementation Strategy

Two activities are currently underway in the Duke service area. Both were developed to determine the most effective means of encouraging the customer to install a geothermal heat pump.

The first activity consists of paying incentives to individual customers who install geothermal heat pumps. The incentive is based on a sliding scale that increases the incentive for more efficient heat pumps. This activity is limited to the Hendersonville Duke Power service area.

The second activity, located in the Charlotte service area, is designed to encourage developers to install geothermal heat pumps in their subdivisions. Two developers have agreed to participate in the pilot with the additional cost of the ground loop piping installation paid for by Duke. This is intended to defray the premium associated with the geothermal heat pump installation and aid in the marketing of the technology to the developer's customers.

Timeframe

Activity	Completion
1. Market Research	Completed
2. Pilot Design	Completed
3. Implementation	4th Quarter 1992
4. Evaluation	2nd Quarter 1993

PILOT: Residential High Efficiency Indoor Lighting

Purpose

The purpose of this pilot is to test customer acceptance of compact fluorescent bulbs, target marketing response rates,and the use of a fulfillment house as a distribution tool.

Background/Assumptions

Compact fluorescent lighting is an energy efficient alternative to the traditional incandescent fixtures found in residences. While residential lighting is a small load relative to the utility's system peak, it is by far the most visible consumer of electricity to the consumer. The pilot, although small in energy and demand impact, has the potential for a large impact based on perceived product value.

In addition to consumer acceptance of a new energy efficient product, the use of target marketing is another issue that will be addressed by the pilot. The Customer Studies Department has software and customer databases available that can segment Duke's Residential Market by their potential interest in a product or program. With the compact fluorescent bulb being a relatively new and unknown product to the majority of Duke's customer's, target marketing can test the acceptance rate of this product among a small yet potentially receptive group.

This pilot was passed through the integration process as an option with the 1990 plan.

Pilot Objectives

1. Test the acceptance of a new consumer product.
2. Test the response rate on target marketing.
3. Test the use of a fulfillment house as a distribution tool.
4. Test consumer satisfaction after the bulbs have been in use for a specified period.

<u>Implementation Strategy</u>

Based on demographic data from Customer Studies, a list of targeted customers was generated for four Duke service areas: Chapel Hill, Charlotte, and Durham in North Carolina and Greenville, South Carolina. These customers were identified as having a greater potential to purchase the bulbs based on their background and lifestyle.

Order forms were developed and mailed to the customers in these areas. The services of an external fulfillment house were retained to process and fill the orders and also handle returns and refunds. This would allow Duke to administer the program without hiring additional staff.

A target amount of 10,000 bulbs were ordered initially to handle the anticipated response. After the mailings, which began the first of September, were completed, customer responses were fulfilled until November 1, 1991. Based on the actual response from the mailings, an additional 2,250 bulbs were ordered to fulfill the orders.

After a period of six months, a follow-up survey will be initiated with both participants and non-participants to gauge level of satisfaction and use for those who bought the bulbs and reasons for not buying from the those who chose not to participate. The survey will assist in the evaluation as to how a full program should be implemented, if proved feasible.

Timeframe

Activity	Completion
1. Market Research	Completed
2. Pilot Design	Completed
3. Implementation	Completed
4. Evaluation	2nd Quarter 1992

This progress report is also in response to N.C. Commission order dated the 28th day of August 1991 in Docket No. E-100, Sub 58.

PILOT: HVAC Tune-Up Program

Purpose

The purpose of this pilot is to: 1) investigate the potential for reducing peak demand by repairing existing residential central air conditioners and heat pumps thereby increasing efficiency and 2) test the effectiveness of "tuning up" the HVAC system for residential customers.

Background/Assumptions

Many residential HVAC systems operate inefficiently due to lack of maintenance, excessive air leaks associated with the ductwork, chronic refrigerant leaks, dirty coils, and other miscellaneous problems. These may lead to high bill complaints and poor customer satisfaction with their system. It also leads to unnecessary energy consumption and peak demand contribution.

Experience has indicated that the existing HVAC contractor infrastructure is not adequately trained to implement a program that effectively locates and repairs these type of problems in a customer's existing system. By adequately training and assisting these contractors in finding these problems, they can be corrected and eliminate both customer irritants associated with their HVAC system and unnecessary energy consumption.

This pilot was passed through the integration process as an option with the 1991 plan.

Pilot Objectives

1. Identify the major problems with existing residential HVAC installations.
2. Design a system to correct the discovered problems and and thus improve homeowner comfort and increase the efficiency of the system.
3. Determine amount of additional training required for existing Comfort Machine dealers and the best source to provide it.
4. Estimate the energy savings by "tuning up" such systems.
5. Determine the amount of rep involvement required.

<u>Implementation Strategy</u>

Implementation of the pilot will begin in June 1992 in Durham with direct mail pieces being sent to single family homes in the area with the targeted response being anticipated at approximately 150 homes. These homes will be segmented into three distinct groups based on the age of the structure with a mix of fossil fuel heated homes included.

Prior to the implementation, training will be given to local HVAC dealers and Duke Representatives on inspection and analysis techniques by a consultant and the North Carolina Alternative Energy Corporation (NCAEC). Techniques involving the use of a blower door, system charging, and coil inspection will be included in the training.

Respondents to the mail order pieces will receive an inspection and analysis of their HVAC system. Fifty dollars (approximately one half) of this inspection will be paid for by Duke.

Upon completion of the analysis, the customer will have the option of allowing the dealer to perform all or part of the repairs identified in the inspection. Duke will pay for 90%, up to $350, of the repairs performed.

Evaluation of the effectiveness of the tune-up will be performed with the assistance of the NCAEC.

Timeframe

Activity	Completion
1. Market Research	2nd Quarter 1992
2. Pilot Design	2nd Quarter 1992
3. Implementation	3rd Quarter 1992
4. Evaluation	2nd Quarter 1992

PILOT: Residential Water Heater Insulating Blanket

Purpose

To promote the use of water heater thermal blankets in the residential market, thereby reducing the losses (and inefficiencies associated with the losses) caused by low levels of insulation.

Background/Assumptions

Electric hot water heaters have losses associated with them due to the insulation being unable to adequately reduce the heat transfer between the tank and the surrounding air. This causes the heating elements in the unit to operate unnecessarily in order to maintain the appropriate water temperature.

In order to reduce the heat transfer, thermal blankets can be added to the water tank that increases the insulation rating. These blankets are relatively inexpensive and simple to install. However, the value of these blankets are not well known to the general public and, in the case of low income households, not considered a necessity.

By promoting the use of these blankets, Duke Power can demonstrate the benefits to the residential market. In addition, unnecessary energy consumption can be reduced, thereby reducing the need for future generating capacity.

This pilot was passed through the integration process as an option with the 1991 plan.

Pilot Objectives

1. To encourage the installation of water heater blankets.
2. To determine the impact of a full program on the existing distribution infrastructure(i.e. warehousing)
3. To determine the manpower requirements and training needed for a full program. The use of a commissioned work force will be evaluated.
4. To determine the impact target marketing has on market acceptance and penetration.
5. To determine the effectiveness of working through agencies (such as HUD) to provide blankets to low-income customers.

Implementation Strategy

The pilot program, which began in April in the Greenville, South Carolina, service area, targets residential customers utilizing electric hot water heaters with emphasis on the following:

1. Special needs customers (low income, handicapped, elderly, etc.)
2. Existing residential customers with rate codes indicating an electric water heater is used.

Three groups will be involved in the installation of the blankets. The first will be comprised of community action volunteers who will install the blankets for special needs customers. The second group will utilize commissioned sales representatives to install the blankets on targeted customers' water heaters. The third group will be Duke Power's own Residential Energy Specialists who will install blankets on an "as needed" basis to enhance their existing services (such as energy audits).

Approximately 400 blankets will be installed in the Greenville area until the end of the pilot, which is set for July of this year. After this, the feasibility of a full program will be assessed.

Timeframe

Activity	Completion
1. Market Research	Completed
2. Pilot Design	Completed
3. Implementation	2nd Quarter 1992
4. Evaluation	3rd Quarter 1992

PILOT: Residential High Efficiency Indoor Lighting

Purpose

The purpose of this pilot is to test customer acceptance of compact fluorescent bulbs, target marketing response rates,and the use of a fulfillment house as a distribution tool.

Background/Assumptions

Compact fluorescent lighting is an energy efficient alternative to the traditional incandescent fixtures found in residences. While residential lighting is a small load relative to the utility's system peak, it is by far the most visible consumer of electricity to the consumer. The pilot, although small in energy and demand impact, has the potential for a large impact based on perceived product value.

In addition to consumer acceptance of a new energy efficient product, the use of target marketing is another issue that will be addressed by the pilot. The Customer Studies Department has software and customer databases available that can segment Duke's Residential Market by their potential interest in a product or program. With the compact fluorescent bulb being a relatively new and unknown product to the majority of Duke's customer's, target marketing can test the acceptance rate of this product among a small yet potentially receptive group.

This pilot was passed through the integration process as an option with the 1990 plan.

Pilot Objectives

1. Test the acceptance of a new consumer product.
2. Test the response rate on target marketing.
3. Test the use of a fulfillment house as a distribution tool.
4. Test consumer satisfaction after the bulbs have been in use for a specified period.

<u>Implementation Strategy</u>

Based on demographic data from Customer Studies, a list of targeted customers was generated for four Duke service areas: Chapel Hill, Charlotte, and Durham in North Carolina and Greenville, South Carolina. These customers were identified as having a greater potential to purchase the bulbs based on their background and lifestyle.

Order forms were developed and mailed to the customers in these areas. The services of an external fulfillment house were retained to process and fill the orders and also handle returns and refunds. This would allow Duke to administer the program without hiring additional staff.

A target amount of 10,000 bulbs were ordered initially to handle the anticipated response. After the mailings, which began the first of September, were completed, customer responses were fulfilled until November 1, 1991. Based on the actual response from the mailings, an additional 2,250 bulbs were ordered to fulfill the orders.

After a period of six months, a follow-up survey will be initiated with both participants and non-participants to gauge level of satisfaction and use for those who bought the bulbs and reasons for not buying from the those who chose not to participate. The survey will assist in the evaluation as to how a full program should be implemented, if proved feasible.

Timeframe

Activity	Completion
1. Market Research	Completed
2. Pilot Design	Completed
3. Implementation	Completed
4. Evaluation	2nd Quarter 1992

This progress report is also in response to N.C. Commission order dated the 28th day of August 1991 in Docket No. E-100, Sub 58.

PILOT: HVAC Tune-Up Program

Purpose

The purpose of this pilot is to: 1) investigate the potential for reducing peak demand by repairing existing residential central air conditioners and heat pumps thereby increasing efficiency and 2) test the effectiveness of "tuning up" the HVAC system for residential customers.

Background/Assumptions

Many residential HVAC systems operate inefficiently due to lack of maintenance, excessive air leaks associated with the ductwork, chronic refrigerant leaks, dirty coils, and other miscellaneous problems. These may lead to high bill complaints and poor customer satisfaction with their system. It also leads to unnecessary energy consumption and peak demand contribution.

Experience has indicated that the existing HVAC contractor infrastructure is not adequately trained to implement a program that effectively locates and repairs these type of problems in a customer's existing system. By adequately training and assisting these contractors in finding these problems, they can be corrected and eliminate both customer irritants associated with their HVAC system and unnecessary energy consumption.

This pilot was passed through the integration process as an option with the 1991 plan.

Pilot Objectives

1. Identify the major problems with existing residential HVAC installations.
2. Design a system to correct the discovered problems and and thus improve homeowner comfort and increase the efficiency of the system.
3. Determine amount of additional training required for existing Comfort Machine dealers and the best source to provide it.
4. Estimate the energy savings by "tuning up" such systems.
5. Determine the amount of rep involvement required.

Implementation Strategy

Implementation of the pilot will begin in June 1992 in Durham with direct mail pieces being sent to single family homes in the area with the targeted response being anticipated at approximately 150 homes. These homes will be segmented into three distinct groups based on the age of the structure with a mix of fossil fuel heated homes included.

Prior to the implementation, training will be given to local HVAC dealers and Duke Representatives on inspection and analysis techniques by a consultant and the North Carolina Alternative Energy Corporation (NCAEC). Techniques involving the use of a blower door, system charging, and coil inspection will be included in the training.

Respondents to the mail order pieces will receive an inspection and analysis of their HVAC system. Fifty dollars (approximately one half) of this inspection will be paid for by Duke.

Upon completion of the analysis, the customer will have the option of allowing the dealer to perform all or part of the repairs identified in the inspection. Duke will pay for 90%, up to $350, of the repairs performed.

Evaluation of the effectiveness of the tune-up will be performed with the assistance of the NCAEC.

Timeframe

Activity	Completion
1. Market Research	2nd Quarter 1992
2. Pilot Design	2nd Quarter 1992
3. Implementation	3rd Quarter 1992
4. Evaluation	2nd Quarter 1992

PILOT: Residential Water Heater Insulating Blanket

Purpose

To promote the use of water heater thermal blankets in the residential market, thereby reducing the losses (and inefficiencies associated with the losses) caused by low levels of insulation.

Background/Assumptions

Electric hot water heaters have losses associated with them due to the insulation being unable to adequately reduce the heat transfer between the tank and the surrounding air. This causes the heating elements in the unit to operate unnecessarily in order to maintain the appropriate water temperature.

In order to reduce the heat transfer, thermal blankets can be added to the water tank that increases the insulation rating. These blankets are relatively inexpensive and simple to install. However, the value of these blankets are not well known to the general public and, in the case of low income households, not considered a necessity.

By promoting the use of these blankets, Duke Power can demonstrate the benefits to the residential market. In addition, unnecessary energy consumption can be reduced, thereby reducing the need for future generating capacity.

This pilot was passed through the integration process as an option with the 1991 plan.

Pilot Objectives

1. To encourage the installation of water heater blankets.
2. To determine the impact of a full program on the existing distribution infrastructure(i.e. warehousing)
3. To determine the manpower requirements and training needed for a full program. The use of a commissioned work force will be evaluated.
4. To determine the impact target marketing has on market acceptance and penetration.
5. To determine the effectiveness of working through agencies (such as HUD) to provide blankets to low-income customers.

Implementation Strategy

The pilot program, which began in April in the Greenville, South Carolina, service area, targets residential customers utilizing electric hot water heaters with emphasis on the following:

1. Special needs customers (low income, handicapped, elderly, etc.)
2. Existing residential customers with rate codes indicating an electric water heater is used.

Three groups will be involved in the installation of the blankets. The first will be comprised of community action volunteers who will install the blankets for special needs customers. The second group will utilize commissioned sales representatives to install the blankets on targeted customers' water heaters. The third group will be Duke Power's own Residential Energy Specialists who will install blankets on an "as needed" basis to enhance their existing services (such as energy audits).

Approximately 400 blankets will be installed in the Greenville area until the end of the pilot, which is set for July of this year. After this, the feasibility of a full program will be assessed.

<u>Timeframe</u>

Activity	Completion
1. Market Research	Completed
2. Pilot Design	Completed
3. Implementation	2nd Quarter 1992
4. Evaluation	3rd Quarter 1992

Commercial/Industrial Pilot Projects

PILOT: Non-Residential Air Conditioning Load Shift (Cool Storage)

Purpose

The purpose of this pilot is to evaluate the application of thermal energy storage systems in Duke's service area. Cool Storage systems reduce summer peak demand by shifting cooling load to off-peak periods and storing that capacity for peak use.

Background/Assumptions

Space cooling of commercial and industrial structures is a significant contributor to Duke's summer peak demand. The technology exists that would allow a customer to use energy during the utility's off-peak hours to cool or freeze water and store it for use in cooling the structure during the utility's on-peak hours. The result is a reduction in the customer's demand for energy during those on-peak hours. This provides lower operating costs for the customer and reduces utility summer peak demands.

Historically, in the Duke Power service area, the high initial cost of storage systems and relatively low utility rates did not produce an economic environment where customers desired to pursue the storage option. The intent of a utility incentive is to improve the economic feasibility of cool storage and increase customer acceptance of the storage alternative.

This pilot was passed through the integration process as an option in the 1990 plan.

Objectives

1. Inventory the available technologies in cool storage.
2. Obtain data on the economics of cool storage including the operating costs, capital costs, utility rate implications and alternatives.
3. Determine the impact of system incentive payments on project economics and the customer's decision making process.
4. Determine the impact of incentive payments for feasibility studies.
5. Collect load shape data on new and existing installations.
6. Use collected data to analyze the feasibility of an incentive program for cool storage and as input into the design process of any future programs.

Implementation Strategy

Two activities are currently underway. One activity is to encourage designers to investigate the feasibility of cool storage facilities by paying 80%, up to $8000, of the cost of feasibility studies performed according to certain guidelines. The second activity is designed to provide an equipment purchase incentive of $200 per kilowatt of peak demand successfully shifted by an installed cool storage system.

Both activities are being implemented across the Duke service area and is available to any qualifying Duke Power customer.

In addition, a number of existing facilities have metering equipment installed to obtain load shape data for use in the modelling process.

The implementation of the pilot will continue through the end of 1992 with the evaluation following.

Timeframe

Activity	Completion
1. Market Research	Completed
2. Pilot Design	Completed
3. Implementation	4th Quarter 1992
4. Evaluation	2nd Quarter 1993

PILOT: Non-Residential Air Conditioning Load Control

Purpose

The purpose of this pilot is to evaluate the participation of non-residential customers in an emergency interruptible service program to central air conditioning systems.

Background/Assumptions

Due to the success of Duke's Residential Air Conditioning Load Control Program, there are more than 140,000 residential air conditioners available for interruption during emergency situations. To expand this activity, a similar program targeted at the non-residential market was found to be a potential source of additional interruptible capacity.

The pilot was initiated to determine program operation characteristics, market potential, and customer acceptance. It was designed to target customers with unitary packages of 10 tons or less.

This pilot was passed through the integration process as an option in the 1990 plan.

Objectives

1. Determine market acceptance and potential.
2. Verify operating characteristics of the load control devices on non-residential air conditioning
3. Determine load shapes and impact on Duke system.

Implementation Strategy

The program was offered to 250 customers served from the same distribution substation in Charlotte with the same format as the existing Residential Air Conditioning Program. A credit was given to the customer based on the size of the connected load. Sixteen customers agreed to participate and were interrupted for a four hour period last July. They were given no notice of the interruption.

A follow up survey was developed and administered afterwards to gauge the impact of the interruption on them. In addition, metering equipment was installed to obtain load shape data. Both of these activities are currently being use for the evaluation.

Timeframe

Activity	Completion
1. Market Research	Completed
2. Pilot Design	Completed
3. Implementation	Completed
4. Evaluation	2nd Quarter 1992

PILOT: Industrial High Efficiency Dust Collection (Completed)

Purpose

The purpose of this pilot was to reduce peak demands and assist customers in conserving energy by encouraging the installation of high efficiency fan motors, fan designs and air handling systems in industrial dust collection systems.

Background/Assumption

A pilot project work team was formed in January of 1991 to investigate the feasibility of a utility incentive program for promoting energy efficiency in industrial dust collection systems. Efficiency improvements can involve high efficiency fan motors, fan designs and air handling systems. Dust collection systems were chosen due to available data from a similar study by the North Carolina Alternative Energy Corporation (NCAEC).

The 1989 study of the North Carolina furniture industry by the NCAEC indicated that dust collection accounts for approximately 20%-25% of the electricity used by the 460 furniture plants in the state. Most dust collection systems in these plants contain outdated technology and consume up to 20% more electricity than modern systems. According to the study, adoption of energy efficient systems could save the state's furniture industry over $2 million annually and reduce electric demand by almost 20 megawatts statewide.

Customers who could improve the efficiency of their dust collection systems would reduce their peak demand on the electric utility, thereby allowing the utility to be more efficient in the use of its facilities. Improvements in the dust collection systems would also increase employee comfort and productivity and assist in complying with state and the national Occupational and Safety Hazards Administration's (OSHA) regulations.

Within the Duke Power service area, the Hickory and High Point regions contain the highest concentration of furniture producers. For this reason, the pilot was targeted for these areas with the intent of encouraging the installation of a high efficiency dust collection system in each area. The total amount of targeted load reduction was 500-600 kilowatts.

In order to offset the additional cost of a high efficiency system as opposed to a standard system, an incentive in the form a set dollar per kilowatt reduction was proposed. Based on avoided cost computations, $170/kw reduction was set as the incentive level.

Objectives

The objectives of the pilot were:

1. Inventory the available technology in dust collection systems.
2. Obtain data on the economics of dust collection systems including the operations costs, capital costs, utility rate implications and alternatives.
3. Determine the impact of utility incentive payments on system economics and the customer's decision-making process.
4. Collect load shape data on pilot and existing installations.

5. Use the collected data to analyze the feasibility of an incentive program for high efficiency dust collection systems.

Results And Conclusions

Research, field visits, and economic analysis indicate that there is little potential for a viable, cost-effective program. In regards to the original objectives of the pilot (as stated in Section III), the following conclusions can be made:

1. Inventory the available technology in dust collection systems.

   In discussions with both customers and design firms, the work team was able to determine what technologies were in use now. There are a wide range of systems found having varying efficiencies with the newer systems reflecting a more efficient design technology. The customers and firms interviewed were knowledgeable of the various types of systems and technologies available.

2. Obtain data on the economics of dust collection systems.

   Through the contacts made with customers and design firms, representative data was obtained and included in the economic analyses performed for Objective (3) below.

3. Determine the impact of utility incentive payments on system economics and the customer's decision-making process.

   Visits with the customers gave the work team an indication of the factors affecting decisions on the dust collection systems. These factors could not only be economically driven but regulatory driven, also, as in the case of indoor air quality.

   The economic drivers included a certain payback period in terms of years, the strength of the furniture market at the time of the project and the magnitude of the cost. Any of these could cause a project to either be approved, postponed, or cancelled.

   Financial data collected from customers and design firms were incorporated in some simple economic analyses involving the projected incentive ($170/KW reduction) identified by the Integration Process. The energy savings from retrofitting existing systems to more efficient design technology were minimal when compared to both the overall retrofit costs and the general plant costs. These calculations showed that the maximum incentive available would have little or no impact on the decision making process of the customer.

4. Collect load shape data on pilot and existing installations.

   Based on the results of the economic analyses performed in Objective (3) above, the work team decided load shape data was unnecessary.

5. Use the collected data to analyze the feasibility of an incentive program for high efficiency dust collection systems.

   Based on the field visits, there was initial interest in the concept of the pilot. However, the potential regarding existing installations appears to be minimal based on the economic analyses performed. Due to the lack of new plant construction, a program targeting this segment of the market would not be useful.

   The general consensus among customers was that regulatory pressure regarding indoor air quality would force plants to modify their systems, perhaps resulting in an increase in fan load. The customers currently making modifications were doing so utilizing point of use systems such as sanding booths.

Recommendations

Based on the results of the pilot's research and field visits and the conclusions drawn by the Work Team from these results, the Work Team recommended that a full scale program promoting incentives for customers to install high efficiency dust collection systems was not prudent.

Although not prudent as a full program, there may be benefits in co-funding a demonstration project. This may be useful for two primary reasons:

1. Demonstrate the benefits of improving the efficiency in dust collection systems to the furniture industry. The benefits may be approached from assisting in meeting increased indoor air quality standards as much as from the economic benefits.
2. Obtain accurate load shape and operating data to verify the information in the AEC report.

A demonstration project would probably be most feasible if incorporated in the construction of a new plat or if an existing customer was planning a modification.

The Work Team recommends that the pilot be completed and a full program not be implemented. It does encourage the Field Marketing representatives to continue to promote the concept of high efficiency dust collection systems and identify potential candidates for a demonstration project.

PILOT: Non-Residential Heat Treating Load Shift (Completed)

Purpose

The purpose of this pilot was to investigate shifting customer's heat treating load processes to off-peak operation by assisting with the purchase of additional production equipment if necessary. The pilot targeted both new and existing loads.

Background/Assumptions

A pilot project work team was formed in January of 1991 to investigate the feasibility of convincing non-residential customers with electric heat treating operations to shift this load to Duke's off-peak demand hours. Load shifting is a classical load shape objective used by utilities to reduce the impact of peak demand on system generation, increase the utilization the utility's most efficient generation, and delay the need for the utility to use (or build) more expensive forms of peaking-only generation.

Duke Power has in its schedule of rates a Time-of-Use rate (Optional Power Service, Time-of-Day) that is designed to encourage customers to optimize load shifting in order to reduce the financial impact of their electrical usage. The pilot was designed in part to encourage customers to maximize the benefits of Rate OPT by shifting their heat treating operations to off-peak hours only, thereby reducing the on-peak demand and energy components of their power bill.

It was recognized that this may impact the production capability of these customers by limiting the output of the heat treating operation. In order to minimize this impact, the pilot would offer incentives based on the amount of load that would be shifted. This incentive could be used to purchase additional heat treating equipment to maintain the production rate necessary for normal output or possibly offset other production costs, such as additional labor costs.

The incentive level was initially set at $165 per nameplate KW of heat treating shifted. The level was determined by inputs to the Least Cost Planning model and would serve as a benchmark to gauge the impact of the incentive on the customer's decision to shift the load.

Objectives

The objectives of the pilot were:

1. Identify the market potential for this application.
2. Identify potential candidates for participation.
3. Quantify the benefits of shifting load, both to the customer and to Duke Power.
4. Identify potential obstacles to shifting load, both to the customer and to Duke Power.

Results And Conclusions

Research, field visits, and economic analysis indicate that there is little potential for a viable, cost-effective program. In regards to the original objectives of the pilot (as stated in Section III), the following conclusions can be made:

1. Identify the market potential

   Although there were a number of customers identified in the prescreening as potential candidates, field visits indicated that the applicability was limited. This was mainly due to the types of heat treating equipment that the customers had in their plants.

   Most electric heating processes found in the field visits had operating characteristics (such as slow response time or the need to maintain a constant product temperature during non-production hours) that would not allow for shifting to off-peak production only. Those that did have processes capable of shifting would have to add equipment to maintain their current production levels.

2. Identify potential candidates for participation

   Field visits to potential candidates indicated that the ability to shift their existing operations would be no simple task. A number of items were identified and found to be serious obstacles to accepting the pilot. Perhaps the largest is the cost of the equipment. Even with the maximum incentive available, the simple payback was beyond the acceptable limits of the customers involved.

   Although this may severely limit the number of customers who may be able to benefit from the pilot, there may be instances where a customer's operation could be modified so that loadshifting would be feasible and beneficial by utilizing the existing Time-Of-Use rate. An example of this would be a customer that had existing underutilized induction heating equipment and could shift production to an off-peak shift.

3. Quantify the benefits of shifting load

   Due to the limited number of potential candidates, determining what benefits could be achieved was difficult to do. Analyses performed on the customers that may be able to participate indicated that the benefit derived from energy savings was slight. A possible benefit may result if additional equipment purchased for off-peak production increased a plant's total output capability.

4. Identify potential obstacles to shifting load

   A number of obstacles, both to the customer and to Duke Power, were identified in the pilot. Among these were:

   A. The high capital cost of additional equipment
   B. The limited availability of qualified operators and supervisors for off-peak operations
   C. The difficulty of insuring permanency with the load shift
   D. The limited types of applicable processes

These obstacles would make a successful full-scale program difficult.

Recommendations

Based on the results of the pilot's research and field visits and the conclusions drawn by the Work Team from these results, it is recommended that a full scale program promoting incentives for customers to shift heat treating loads to off-peak hours is not prudent.

Although not feasible for a full-scale program, there are indications that a niche market exists. Such a niche market may be more prudently addressed through the Demand Side Bidding Program.

Among the qualifications for a niche market candidate:

1. A customer that has existing induction equipment that is under utilized and can shift production on that existing piece of equipment.
2. Flexibility in scheduling operators for the equipment.

The Work Team also recommends that the Field Marketing representatives continue to encourage the optimizing of the Time-Of-Use Rate Schedule OPT for shifting loads to off-peak hours. The schedule can provide some financial incentive for customers who meet the above qualifications.

In conclusion, the Work Team recommends that the Heat Treating Load Shift option be discontinued as a viable Demand Side Option with little or no potential for a full program at this time.

PILOT: Non-Residential High Efficiency Indoor Lighting

Purpose

To determine the feasibility of Duke Power implementing a full scale indoor lighting program in the mid 1990's that will promote the installation of high efficiency lighting technology in the commercial and industrial market. A full scale program would help to defer additional generation that may be needed to meet system load demands.

Background/Assumptions

The first phase of Duke Power's High Efficiency Lighting pilot project was initiated in 1991 to identify and investigate the various utilities around the nation that have similar programs already in place. The purpose in this was to determine the strengths and weaknesses of these programs and use this information to aid in the development of a Duke program. In addition to assessing the existing utility programs, the available technologies in the area of high efficiency lighting were studied. Preliminary market research included interviewing local vendors, consultants, and government agencies involved in commercial and industrial lighting in addition to a commercial customer survey that had a lighting component.

After completing these first objectives, the decision was made to move from a research-oriented project to an implementation-oriented one. The work team developed a list of objectives that would address issues identified in the research phase and, if successfully answered, would permit the implementation of a full-scale program.

This pilot was passed through the integration process as an option with the 1990 plan.

Pilot Objectives

Six areas were identified as being critical issues that the pilot needed to address. They are listed in no ranked order of importance as each is an integral part of the whole pilot.

1. **Market Penetration** - A number of items can affect how many customers will embrace a program and how successful it will be.

   A. Determine the effect of varying the incentive level paid by Duke and the delivery method on the market penetration. Also measuring these effects on free ridership and by market segments.

   B. Determine what type of design program will have the most effect on the market penetration.

      1) <u>Customized</u> - In this program, the entire lighting layout is redesigned with high efficient lighting technology and the incentive on the demand reduction. It is expected that this program would have more application and acceptance in the larger customer arena.

      2) <u>Technology</u> - In this program, it is to be the most beneficial to smaller retrofit projects where a standardized form is used to help replace older fixtures with newer, more efficient ones. It should be determine how much impact this program would have on load reduction and if only smaller customers would indeed find this to be the most beneficial means of implementing the program.

2. **Load Shape** - By monitoring some of the pilot locations, a more accurate determination of the effect of the program on the load shape of the market can be found.

3. **Costs** - The pilot should help to determine the level of costs to the Company and to the customer. Some of these costs would include administrative, labor, incentive, and customer costs.

4. **Option Delivery Methods** - The involvement of Duke personnel, the existing lighting industry infrastructure, and consultants in delivering the program to the customer is a question that the pilot can answer. Also, what is the most effective vehicle for communicating the program to the customer?

5. **Product Evaluation** - To maximize the effectiveness of a program, the proper technologies must be identified as being the most efficient.

6. **Program Evaluation** - How effective is the pilot project on influencing the market?

   A. Permanence - The long-term success and duration of the technologies on reducing the lighting demand must identified.

   B. Regulations - The effect of a full program on influencing building codes to encourage the installation of high efficiency indoor lighting.

Implementation Strategy

The research phase of this pilot was conducted in 1991 to assess what is currently happening in the area of indoor lighting. Among the activities that took place was a survey and review of other utility lighting incentive programs. This resulted in a wide variety of approaches with varying degrees of success. This background knowledge will be used to design Duke's Lighting Pilot. Another activity that occurred in the research phase was an assessment of the current lighting technologies that are available to customers. How other utilities incorporated these technologies into their programs was studied and will also be incorporated into the Design phase.

A customer survey was developed that incorporated lighting questions and should provide information concerning primarily incentive levels. This will utilized in the Design phase when completed.

Upon completion of the preliminary research, it was decided that a third party with previous experience in designing and implementing a lighting program should be enlisted to assist the Work Team in this pilot. A Request for Proposals was sent out to third party consultants that were identified by the Team as having previous experience in this area. After a thorough selection process, a vendor was selected and is currently assisting in the Design,Implementation, and Evaluation of the Lighting Pilot.

Timeframe

Activity	Completion
1. Market Research	3rd Quarter 1992
2. Pilot Design	4th Quarter 1992
3. Implementation	2nd Quarter 1994
4. Evaluation	4th Quarter 1994

PILOT: Motor Systems

Purpose

To improve the efficiency and effectiveness of motors in meeting specific end-use applications. This will be a multi-part project with the initial phase being the identification of the issues and the assessment of the market potential. After the research phase, an evaluation will be necessary to determine what position Duke should take on a pilot DSM program.

Background/Assumptions

Because motor driven end uses account for approximately 70% of industrial electricity consumption, motors have gained considerable attention as a load modification avenue. Alternating current (AC) motors power numerous types of industrial loads - from pumps and fans to the many grinding, mixing, and machining end-use operations so pervasive in manufacturing. Because of their large presence in the industrial sector, motors and motor drives suggest significant load modification potential.

For applications involving variable load conditions, savings can be achieved by using an electronic adjustable speed drive (ASD) to vary the speed of a single speed motor. The ASD uses semiconductor devices and switching circuits to provide a variable frequency power output to an AC motor. By varying motor speed to meet process requirements, ASDs can greatly enhance efficiency compared to mechanical throttling devices and provide many other benefits such as smoother operation and prolonged motor life. On the negative side, ASDs may cause power quality problems.

(SOURCE: EPRI Report #CU-7089)

This pilot was passed through the integration process as an option with the 1991 Plan.

Pilot Objectives

1. To identify the key issues that need to be addressed in a full program.
2. To identify the true market potential.
3. Assess the current programs that other utilities have and learn what have been their successes and failures.
4. To gain a better understanding of high efficiency motor technology and its impacts on our system.

<u>Implementation Strategy</u>

The intent of this first phase of the Motor Systems pilot will be to research and identify the key issues. The option focuses on improving the efficiency and effectiveness of motors in meeting specific end-use applications. It is necessary to consider both the motor efficiency and efficiency of the driven devices (i.e. pumps, fans, compressors, etc.) in order to develop the most cost effective program for our customers. This poses a very large and complex task.

Similar to the Research Phase of the Lighting Pilot, the first phase of the Motors Pilot will be devoted to studying what is currently happening in the industry. Other utility programs will be assessed for their effectiveness and identification of key technologies and issues. Market research will be performed in order to identify both the market potential and market segments.

Once this has been done, an assessment of the needs and objectives specific to the Duke Power service area can be identified and strategies laid out to address them. The Work Team members are currently being identified and it is anticipated that the majority of 1992 will be spent researching the current utility programs and identifying the key issues to be addressed by the implementation of a Duke Power program.

Timeframe

Activity	Completion
1. Market Research	4th Quarter 1992
2. Pilot Design	TBD
3. Implementation	TBD
4. Evaluation	TBD

PILOT: Standby Generator With Backfeed

Purpose

The purpose of this pilot was to evaluate the technical feasibility of allowing parallel connections of customer owned generation to the Duke Power system. The focus of the pilot was centered on technical feasibility, utility system effects, and associated customer and utility costs.

Background/Assumptions

The Standby Generation with Backfeed pilot was chosen as an extension of Duke's existing Standby Generator Program. It was viewed as having the potential to provide additional emergency interruptible capacity.

The particular connection that has been defined as a "parallel backfeed connection" means the generator could be connected in parallel with the utility, serve the customer's load, and export any additional power available up to the generator rating onto the utility grid. From an operational standpoint, this differs significantly from the existing program where a customer must disconnect from the utility system and only serve the load that is physically connected to the generator.

Although utilities have experience with the parallel backfeed type of connection used by PURPA base-load type generators, there is little or no experience associated with allowing a similar connection for emergency standby generators. This is due to the very different operational nature of the emergency standby generator.

This pilot was passed through the integration process as an option with the 1990 plan and again in 1991.

Objectives

Due to the unknowns associated with the pilot, the following objectives have been identified to address the technical uncertainties:

1. Proper operation and protection of the utility and generator systems.
2. Determination of customer and Duke costs.

<u>Implementation Strategy</u>

Test sites were established with Duke customers that had existing on-site generation. These customers were selected as being representative of the various conditions that may be encountered on the Duke system. Once established, monitoring equipment was installed to gather data that could be used in computer models to guage the impact on the local distribution system.

<u>Results and Conclusions</u>

1. Proper operation and protection of the utility and generator systems.

Based on the information collected from the test locations, extensive operational modelling of the distribution circuit would be required to allow backfeed connections. Then, based on this modelling, modifications to the circuit's protective devices would be necessary. Both the modelling and the circuit modifications are costly and modelling based on actual field data collected showed that modifications could degrade circuit performance to some extent and increase the potential for equipment damage or human injury. However, with certain limitations, the effects on circuit operation and safety could be minimized but never eliminated.

Some of the limitations can be removed however if parallel connections were allowed up to the limits of the customer's load. In other words, the customer could connect the generator in parallel but not be allowed to export power onto the utility grid. This would reduce the capacity available but would minimize the costs associated with connecting to the Duke system.

The limitations are generally determined using data unique to the circuit and customer's generator. Therefore, potential installations would have to be evaluated on a case by case basis to see if the circuit could be configured to operate properly with the generator in parallel. Furthermore, only one backfeeding generator could be allowed per circuit. This is due to the inability to properly and safely protect multiple installations on the same circuit.

2. Determination of Duke and Customer costs.

The costs for Duke to upgrade its circuits to allow backfeed connections were found to be significant but still within the limits as modelled in the original option.

In addition, the costs to the customer are also significant. The additional investment in paralleling switchgear that is required for backfeed operation was not offset by the proposed credit that was modelled in the original option evaluation. However, it was discovered that many new generator systems being put in place today are being ordered with paralleling gear with customers justifying the additional investment for operational reasons. In these situations, the additional cost for operational software to allow backfeed operations becomes economically reasonable.

Recommendations

The Work Team feels that the original objectives of this pilot have been met and that the pilot is complete. It was determined that parallel backfeed connections are possible albeit on a limited basis and at the expense of circuit operational performance and safety.

Due to the compromises in circuit performance and safety, the Work Team recommends that the Standby Generator with Backfeed pilot not be implemented as a full program at this time. Other programs will be considered in its place that do not effect circuit performance or compromise safety. Duke will continue to investigate other means of obtaining and quantifying least cost capacity that may be available from customer-owned standby generators.

Appendix VI-4: DSM Program and Option Assumptions and Other Data

The following tables list the assumptions and other data used for each option that was forwarded to resource integration for the 1991 IP process.

Similar to the Research Phase of the Lighting Pilot, the first phase of the Motors Pilot will be devoted to studying what is currently happening in the industry. Other utility programs will be assessed for their effectiveness and identification of key technologies and issues. Market research will be performed in order to identify both the market potential and market segments.

Once this has been done, an assessment of the needs and objectives specific to the Duke Power service area can be identified and strategies laid out to address them. The Work Team members are currently being identified and it is anticipated that the majority of 1992 will be spent researching the current utility programs and identifying the key issues to be addressed by the implementation of a Duke Power program.

<u>Timeframe</u>

Activity	**Completion**
1. Market Research	4th Quarter 1992
2. Pilot Design	TBD
3. Implementation	TBD
4. Evaluation	TBD

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Recommendations

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Appendix VI-4: DSM Program and Option Assumptions and Other Data

The following tables list the assumptions and other data used for each option that was forwarded to resource integration for the 1991 IP process.

Demand Side Program: RESIDENTIAL LOAD CONTROL - WATER HEATING (EXISTING)

DSM Type: INTERRUPTIBLE

Description: This program allows the direct control of a customer's water heater load.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-0.363	KW per customer
Winter	-0.750	KW per customer
Spring	0.000	KW per customer
Fall	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RS CAT 2	Use proposed rates	
Energy Sales Price:	$0.07925	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	- Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$0	per unit per year
Administration cost =	$0	$0	per year

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
One time equipment charge	0	
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	124714	2001	0
1992	0	2002	0
1993	0	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	124714	124714
1992	0	0	0	0	0	124714
1993	0	0	0	0	0	124714
1994	0	0	0	0	0	124714
1995	0	0	0	0	0	124714
1996	0	0	0	0	0	124714
1997	0	0	0	0	0	124714
1998	0	0	0	0	0	124714
1999	0	0	0	0	0	124714
2000	0	0	0	0	0	124714
2001	0	0	0	0	0	124714
2002	0	0	0	0	0	124714
2003	0	0	0	0	0	124714
2004	0	0	0	0	0	124714
2005	0	0	0	0	0	124714
2006	0	0	0	0	0	124714
2007	0	0	0	0	0	124714
2008	0	0	0	0	0	124714
2009	0	0	0	0	0	124714
2010	0	0	0	0	0	124714

Demand Side Program: RESIDENTIAL LOAD CONTROL - WATER HEATING

DSM Type: INTERRUPTIBLE

Description: This program allows the direct control of a customer's water heater load.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-0.334	KW per customer
Winter	-0.690	KW per customer
Spring	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RS CAT 2	Use proposed rates	
Energy Sales Price:	$0.07925	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$2.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COSTS (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$1,000.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$4,000	$2,000	per year
Marketing Development (demonstration, travel, misc.)	$4,000	$500	per year
Marketing GO Labor =	$2,600	$2,000	per year
Field sales labor	$13	$13	per unit per year
Administration cost =	$7,500	$7,500	per year

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$66.76	per unit
Labor Costs =	$69.44	per unit
One time equipment charge	142500	
b. Annual Equipment Maint. (O & M) =	$9.40	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$35.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	2842
1992	7915	2002	2838
1993	8021	2003	2848
1994	8000	2004	2833
1995	8027	2005	2800
1996	7948	2006	0
1997	7946	2007	0
1998	7938	2008	0
1999	7941	2009	0
2000	7930	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	7915	7915	0	7915	7915
1993	0	8021	8021	0	15936	15936
1994	0	8000	8000	0	23936	23936
1995	0	8027	8027	0	31963	31963
1996	0	7948	7948	0	39911	39911
1997	0	7946	7946	0	47857	47857
1998	0	7938	7938	0	55795	55795
1999	0	7941	7941	0	63736	63736
2000	0	7930	7930	0	71666	71666
2001	0	2842	2842	0	74508	74508
2002	0	2838	2838	0	77346	77346
2003	0	2848	2848	0	80194	80194
2004	0	2833	2833	0	83027	83027
2005	0	2800	2800	0	85827	85827
2006	0	0	0	0	85827	85827
2007	0	0	0	0	85827	85827
2008	0	0	0	0	85827	85827
2009	0	0	0	0	85827	85827
2010	0	0	0	0	85827	85827

Demand Side Program: RESIDENTIAL LOAD CONTROL - AIR CONDITIONING (EXISTING)

DSM Type: INTERRUPTIBLE

Description: This program allows the direct control of the compressor load of a customer's central air conditioner.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-3.170	KW per customer
Winter	0.000	KW per customer
Spring	0.000	KW per customer
Fall	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: RS CAT 3 Use proposed rates
Energy Sales Price: $0.07549 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per 4 cooling months per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$0	per unit per year
Administration cost =	$0	$0	per year

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
One time equipment cost	0	
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	169632	2001	0
1992	0	2002	0
1993	0	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units: Free Riders	Incremental Units: Non-Free Riders	Incremental Units: Total	Total Cumulative Units: Free Riders	Total Cumulative Units: Non-Free Riders	Total Cumulative Units: Total
Accom. 1991	0	0	0	0	169632	169632
1992	0	0	0	0	0	169632
1993	0	0	0	0	0	169632
1994	0	0	0	0	0	169632
1995	0	0	0	0	0	169632
1996	0	0	0	0	0	169632
1997	0	0	0	0	0	169632
1998	0	0	0	0	0	169632
1999	0	0	0	0	0	169632
2000	0	0	0	0	0	169632
2001	0	0	0	0	0	169632
2002	0	0	0	0	0	169632
2003	0	0	0	0	0	169632
2004	0	0	0	0	0	169632
2005	0	0	0	0	0	169632
2006	0	0	0	0	0	169632
2007	0	0	0	0	0	169632
2008	0	0	0	0	0	169632
2009	0	0	0	0	0	169632
2010	0	0	0	0	0	169632

Demand Side Program: RESIDENTIAL LOAD CONTROL - AIR CONDITIONING

DSM Type: INTERRUPTIBLE

Description: This program allows the direct control of the compressor load of a customer's central air conditioner.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-2.916	KW per customer
Winter	0.000	KW per customer
Spring	0.000	KW per customer
Fall	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: RS CAT 3 Use proposed rates
Energy Sales Price: $0.07549 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$15.60	per 4 cooling months per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COSTS (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$1,000.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$4,000	$4,000	per year
Marketing Development (demonstration, travel, misc.)	$4,000	$500	per year
Marketing GO Labor =	$2,600	$1,000	per year
Field sales labor	$20	$20	per unit per year
Administration cost =	$7,500	$7,500	per year

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$66.76	per unit
Labor Costs =	$69.44	per unit
One time equipment cost	480000	
b. Annual Equipment Maint. (O & M) =	$9.40	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$35.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	9939
1992	25891	2002	9927
1993	26263	2003	9960
1994	26189	2004	9907
1995	26286	2005	10073
1996	26010	2006	10242
1997	26003	2007	10414
1998	25974	2008	10589
1999	25982	2009	10767
2000	25947	2010	10818

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	25891	25891	0	25891	25891
1993	0	26263	26263	0	52154	52154
1994	0	26189	26189	0	78343	78343
1995	0	26286	26286	0	104629	104629
1996	0	26010	26010	0	130639	130639
1997	0	26003	26003	0	156642	156642
1998	0	25974	25974	0	182616	182616
1999	0	25982	25982	0	208598	208598
2000	0	25947	25947	0	234545	234545
2001	0	9939	9939	0	244484	244484
2002	0	9927	9927	0	254411	254411
2003	0	9960	9960	0	264371	264371
2004	0	9907	9907	0	274278	274278
2005	0	10073	10073	0	284351	284351
2006	0	10242	10242	0	294593	294593
2007	0	10414	10414	0	305007	305007
2008	0	10589	10589	0	315596	315596
2009	0	10767	10767	0	326363	326363
2010	0	10818	10818	0	337181	337181

Demand Side Program: RESIDENTIAL CONTROLLED OFF PEAK WATER HEATING

DSM Type: Load Shift

Description: This program causes customers to shift water heating usage to off-peak periods. Load contol devices are used to control the times that the water heater is allowed to operate.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-0.568	kw/unit
Summer:	-0.329	kw/unit
Winter:	-0.699	kw/unit
Fall:	-0.568	kw/unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction
(Includes Line Loss)

Spring	-0.617	KW per customer
Summer	-0.357	KW per customer
Winter	-0.759	KW per customer
Fall	-0.617	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer

Total annual 0 KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	WC	Use proposed rates	
Energy Sales Price:	$0.03100	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$0	per unit per year
Administration cost =	$0	$0	per year

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
One time equipment charge	0	
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	43399	2001	0
1992	0	2002	0
1993	0	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	43399	43399
1992	0	0	0	0	0	43399
1993	0	0	0	0	0	43399
1994	0	0	0	0	0	43399
1995	0	0	0	0	0	43399
1996	0	0	0	0	0	43399
1997	0	0	0	0	0	43399
1998	0	0	0	0	0	43399
1999	0	0	0	0	0	43399
2000	0	0	0	0	0	43399
2001	0	0	0	0	0	43399
2002	0	0	0	0	0	43399
2003	0	0	0	0	0	43399
2004	0	0	0	0	0	43399
2005	0	0	0	0	0	43399
2006	0	0	0	0	0	43399
2007	0	0	0	0	0	43399
2008	0	0	0	0	0	43399
2009	0	0	0	0	0	43399
2010	0	0	0	0	0	43399

Demand Side Program: RESIDENTIAL CONTROLLED OFF PEAK WATER HEATING
WC SUBMETERED LOWER RATE

DSM Type: Load Shift

Description: This program causes customers to shift water heating usage to off-peak periods. Load contol devices are used to control the times that the water heater is allowed to operate.

Assumptions:

1. Unit Definition: unit
2. Units per Average Customer: 1 unit per customer
   Average Customer Usage 3090 kwh per year
   Percent of Market Retention 0.15
   Forecast recognizes 15% loss if rate did not exist. Therefore, revenue reflects additional energy sales.
3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-0.523	kw/unit
Summer:	-0.303	kw/unit
Winter:	-0.643	kw/unit
Fall:	-0.523	kw/unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction
(Includes Line Loss)

Spring	-0.568	KW per customer
Summer	-0.329	KW per customer
Winter	-0.699	KW per customer
Fall	-0.568	KW per customer

Note: Peak reduction reflects system reliability factor as determined by PLC task force.

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer

Total annual 0 KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	WC	Use proposed rates	
Energy Sales Price:	$0.03100	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.04	per kwh per month

8. DUKE COSTS (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)		First Year	Annual	
	Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
	Marketing Advertising = (brochures, promotional, air time)	$7,550	$1,000	per year
	Marketing Development (demonstration, travel, misc.)	$3,000	$0	per year
	Marketing GO Labor =	$2,500	$2,000	per year
	Field sales labor	$13	$13	per unit per year
	Administration cost =	$5,000	$5,000	per year
Distribution Costs				
	a. Installation (Capital Costs)			
	Material Costs =	$146.41	per unit	
	Labor Costs =	$72.09	per unit	
	One time equipment charge	63750		
	b. Annual Equipment Maint. (O & M) =	$9.40	per unit per year	

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes			
	a. Installation and equipment costs=	$35.00	per unit
	b. Annual Maintenance cost changes =	$0.00	per unit per year
	c.		per unit per year
	d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	3500	2002	0
1993	3500	2003	0
1994	3500	2004	0
1995	3500	2005	0
1996	3500	2006	0
1997	3500	2007	0
1998	3500	2008	0
1999	3500	2009	0
2000	3500	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	3500	3500	0	3500	3500
1993	0	3500	3500	0	7000	7000
1994	0	3500	3500	0	10500	10500
1995	0	3500	3500	0	14000	14000
1996	0	3500	3500	0	17500	17500
1997	0	3500	3500	0	21000	21000
1998	0	3500	3500	0	24500	24500
1999	0	3500	3500	0	28000	28000
2000	0	3500	3500	0	31500	31500
2001	0	0	0	0	31500	31500
2002	0	0	0	0	31500	31500
2003	0	0	0	0	31500	31500
2004	0	0	0	0	31500	31500
2005	0	0	0	0	31500	31500
2006	0	0	0	0	31500	31500
2007	0	0	0	0	31500	31500
2008	0	0	0	0	31500	31500
2009	0	0	0	0	31500	31500
2010	0	0	0	0	31500	31500

Demand Side Program: RESIDENTIAL CONTROLLED OFF PEAK WATER HEATING
FLAT MONTHLY PAYMENT

DSM Type: LOAD SHIFT

Description: This program causes customers to shift water heating usage to off-peak periods. The Company uses load control devices to control the times during which the water heater is allowed to operate.

Assumptions:
1. Unit Definition: unit
2. Units per Average Customer: 1 unit per customer
Average Customer Usage 3090 kwh per year
Percent of Market Retention 0.15
Forecast recognizes 15% loss if rate did not exist. Therefore, revenue reflects additional energy sales.
3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-0.357	KW per customer
Winter	-0.759	KW per customer
Spring	-0.617	KW per customer
Fall	-0.617	KW per customer

Note: Peak reduction reflects system reliability factor as determined by PLC task force.

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: RS CAT 2 Use proposed rates
Energy Sales Price: $0.07925 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$7.33	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$10,000.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$7,550	$3,500	per year
Marketing Development (demonstration, travel, misc.)	$6,000	$0	per year
Marketing GO Labor =	$2,500	$1,000	per year
Field sales labor	$23	$23	per unit per year
Administration cost =	$5,000	$5,000	per year
Distribution Costs			
a. Installation (Capital Costs)			
Material Costs =	$66.41	per unit	
Labor Costs =	$69.44	per unit	
One time equipment cost	63750		
b. Annual Equipment Maint. (O & M) =	$9.40	per unit per year	

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes		
a. Installation and equipment costs=	$35.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	3500	2002	0
1993	3500	2003	0
1994	3500	2004	0
1995	3500	2005	0
1996	3500	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	3500	3500	0	3500	3500
1993	0	3500	3500	0	7000	7000
1994	0	3500	3500	0	10500	10500
1995	0	3500	3500	0	14000	14000
1996	0	3500	3500	0	17500	17500
1997	0	0	0	0	17500	17500
1998	0	0	0	0	17500	17500
1999	0	0	0	0	17500	17500
2000	0	0	0	0	17500	17500
2001	0	0	0	0	17500	17500
2002	0	0	0	0	17500	17500
2003	0	0	0	0	17500	17500
2004	0	0	0	0	17500	17500
2005	0	0	0	0	17500	17500
2006	0	0	0	0	17500	17500
2007	0	0	0	0	17500	17500
2008	0	0	0	0	17500	17500
2009	0	0	0	0	17500	17500
2010	0	0	0	0	17500	17500

Demand Side Program: HIGH EFFICIENCY HEAT PUMP PAYMENT

DSM Type: CONSERVATION

Description: Encouraging the purchase and use of higher efficiency models of heat pumps than the consumer would have purchased otherwise. The analysis assumes an incremental increase of 1.49 SEER points based on pilot project results.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction (Includes Line Loss)

Summer	-0.342	KW per customer
Winter	0.000	KW per customer
Spring	-0.104	KW per customer
Fall	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	-629	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RS CAT 4	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.00	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$0	per unit per year
Administration cost =	$0	$0	per year

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 0%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	4850	2001	0
1992	5335	2002	0
1993	5869	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders 1 22.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	1067	3783	4850	1067	3783	4850
1992	1174	4161	5335	2241	7944	10185
1993	1291	4578	5869	3532	12522	16054
1994	0	0	0	3532	12522	16054
1995	0	0	0	3532	12522	16054
1996	0	0	0	3532	12522	16054
1997	0	0	0	3532	12522	16054
1998	0	0	0	3532	12522	16054
1999	0	0	0	3532	12522	16054
2000	0	0	0	3532	12522	16054
2001	0	0	0	3532	12522	16054
2002	0	0	0	3532	12522	16054
2003	0	0	0	3532	12522	16054
2004	0	0	0	3532	12522	16054
2005	0	0	0	3532	12522	16054
2006	0	0	0	3532	12522	16054
2007	0	0	0	3532	12522	16054
2008	0	0	0	3532	12522	16054
2009	0	0	0	3532	12522	16054
2010	0	0	0	3532	12522	16054

Demand Side Program: HIGH EFFICIENCY CENTRAL AIR CONDITIONING PAYMENT

DSM Type: CONSERVATION

Description: Encouraging the purchase and use of higher efficiency models of Central Air conditioners than the consumer would have purchased otherwise. Data is from the 1990 Pilot Project for incentives.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-0.342	KW per customer
Winter	0.000	KW per customer
Spring	0.000	KW per customer
Fall	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	-353	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RS CAT 4	Use proposed rates	
Energy Sales Price:	$0.07459	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$10,000.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$70,000	$6,000	per year
Marketing Development (demonstration, travel, misc.)	$5,000	$0	per year
Marketing GO Labor =	$1,200	$2,000	per year
Field sales labor	$32	$32	per unit per year
Administration cost =	$60,000	$60,000	per year

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$1,800.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	1617	2001	0
1992	1778	2002	0
1993	1956	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders 1 22.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	356	1261	1617	356	1261	1617
1992	391	1387	1778	747	2648	3395
1993	430	1526	1956	1177	4174	5351
1994	0	0	0	1177	4174	5351
1995	0	0	0	1177	4174	5351
1996	0	0	0	1177	4174	5351
1997	0	0	0	1177	4174	5351
1998	0	0	0	1177	4174	5351
1999	0	0	0	1177	4174	5351
2000	0	0	0	1177	4174	5351
2001	0	0	0	1177	4174	5351
2002	0	0	0	1177	4174	5351
2003	0	0	0	1177	4174	5351
2004	0	0	0	1177	4174	5351
2005	0	0	0	1177	4174	5351
2006	0	0	0	1177	4174	5351
2007	0	0	0	1177	4174	5351
2008	0	0	0	1177	4174	5351
2009	0	0	0	1177	4174	5351
2010	0	0	0	1177	4174	5351

Demand Side Program: RESIDENTIAL ADD-ON (DUAL FUEL) HEAT PUMP

DSM Type: CONSERVATION

Description: Encouraging the installation of heat pumps in homes with existing oil furnaces. The analysis assumes an increase in the SEER rating of the A/C Component from 7.5 to 12.0.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 tons per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-1.294	KW per customer
Winter	0.520	KW per customer
Spring	0.861	KW per customer
Fall	0.000	KW per customer

Revenue to company should be divided by lineloss for energy losses

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	1,291	KWH per customer

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	800	2001	0
1992	5000	2002	0
1993	7500	2003	0
1994	9500	2004	0
1995	11500	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 5.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	40	760	800	0	800	800
1992	250	4750	5000	250	5550	5800
1993	375	7125	7500	625	12675	13300
1994	475	9025	9500	1100	21700	22800
1995	575	10925	11500	1675	32625	34300
1996	0	0	0	1675	32625	34300
1997	0	0	0	1675	32625	34300
1998	0	0	0	1675	32625	34300
1999	0	0	0	1675	32625	34300
2000	0	0	0	1675	32625	34300
2001	0	0	0	1675	32625	34300
2002	0	0	0	1675	32625	34300
2003	0	0	0	1675	32625	34300
2004	0	0	0	1675	32625	34300
2005	0	0	0	1675	32625	34300
2006	0	0	0	1675	32625	34300
2007	0	0	0	1675	32625	34300
2008	0	0	0	1675	32625	34300
2009	0	0	0	1675	32625	34300
2010	0	0	0	1675	32625	34300

Demand Side Program: HIGH EFFICIENCY FREEZER PAYMENT

DSM Type: CONSERVATION

Description: Encouraging the purchase and use of higher efficiency models of freezers than the consumer would have purchased otherwise.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 tons per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit DIVERSIFIED SYSTEM PEAK HOUR BY SEASON

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-0.074	KW per customer
Winter	-0.042	KW per customer
Spring	-0.602	KW per customer
Fall	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	(414)	KWH per customer

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	1200	2001	0
1992	2600	2002	0
1993	3200	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 50.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Incremental Units Non-Free Riders	Incremental Units Total	Total Cumulative Units Free Riders	Total Cumulative Units Non-Free Riders	Total Cumulative Units Total
Accom. 1991	600	600	1200	0	1200	1200
1992	1300	1300	2600	1300	2500	3800
1993	1600	1600	3200	2900	4100	7000
1994	0	0	0	2900	4100	7000
1995	0	0	0	2900	4100	7000
1996	0	0	0	2900	4100	7000
1997	0	0	0	2900	4100	7000
1998	0	0	0	2900	4100	7000
1999	0	0	0	2900	4100	7000
2000	0	0	0	2900	4100	7000
2001	0	0	0	2900	4100	7000
2002	0	0	0	2900	4100	7000
2003	0	0	0	2900	4100	7000
2004	0	0	0	2900	4100	7000
2005	0	0	0	2900	4100	7000
2006	0	0	0	2900	4100	7000
2007	0	0	0	2900	4100	7000
2008	0	0	0	2900	4100	7000
2009	0	0	0	2900	4100	7000
2010	0	0	0	2900	4100	7000

Demand Side Program: HIGH EFFICIENCY REFRIGERATOR PAYMENT

DSM Type: CONSERVATION

Description: Encouraging the purchase and use of higher efficiency models of refrigerators than the consumer would have purchased otherwise.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 tons per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction
(Includes Line Loss)

Summer	-0.067	KW per customer
Winter	-0.038	KW per customer
Spring	-0.054	KW per customer
Fall	0.000	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	(315)	KWH per customer

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	2500	2001	0
1992	5800	2002	0
1993	6200	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 50.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	1250	1250	2500	0	2500	2500
1992	2900	2900	5800	2900	5400	8300
1993	3100	3100	6200	6000	8500	14500
1994	0	0	0	6000	8500	14500
1995	0	0	0	6000	8500	14500
1996	0	0	0	6000	8500	14500
1997	0	0	0	6000	8500	14500
1998	0	0	0	6000	8500	14500
1999	0	0	0	6000	8500	14500
2000	0	0	0	6000	8500	14500
2001	0	0	0	6000	8500	14500
2002	0	0	0	6000	8500	14500
2003	0	0	0	6000	8500	14500
2004	0	0	0	6000	8500	14500
2005	0	0	0	6000	8500	14500
2006	0	0	0	6000	8500	14500
2007	0	0	0	6000	8500	14500
2008	0	0	0	6000	8500	14500
2009	0	0	0	6000	8500	14500
2010	0	0	0	6000	8500	14500

Demand Side Program: RESIDENTIAL INSULATION - NEW RESIDENCES (2% DISCOUNT)

DSM Type: LOAD BUILDING

Description: Combination of costs involved in the High Efficiency Heat Pump sales to new homes, electric water heater sales program, and insulation up to RC 2.% standards.

Assumptions:

1. Unit Definition: unit
2. Units per Average Customer: 1 unit per customer
   Heat pump SEER is 12 in a MAX home
   A/C is SEER 9.5 in gas heated home.
3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction (Includes Line Loss)

Summer	-0.755	KW per customer
Winter	2.495	KW per customer
Spring	0.398	KW per customer
Fall	0.736	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)

(no line losses included)

	Energy (KWH)	
Summer	-554.0	KWH per customer
Winter	2705.0	KWH per customer
Spring	323.0	KWH per customer
Fall	548.0	KWH per customer
Total annual	3022	kwh

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RE-2	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.00	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$0	per unit per year
Administration cost =	$0	$0	per year

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	10000	2001	0
1992	13800	2002	0
1993	14600	2003	0
1994	16200	2004	0
1995	20000	2005	0
1996	20000	2006	0
1997	20000	2007	0
1998	20000	2008	0
1999	20000	2009	0
2000	20000	2010	0

12. Free Riders: 40.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	10000	10000
1992	5520	8280	13800	5520	8280	13800
1993	5840	8760	14600	11360	17040	28400
1994	6480	9720	16200	17840	26760	44600
1995	8000	12000	20000	25840	38760	64600
1996	8000	12000	20000	33840	50760	84600
1997	8000	12000	20000	41840	62760	104600
1998	8000	12000	20000	49840	74760	124600
1999	8000	12000	20000	57840	86760	144600
2000	8000	12000	20000	65840	98760	164600
2001	0	0	0	65840	98760	164600
2002	0	0	0	65840	98760	164600
2003	0	0	0	65840	98760	164600
2004	0	0	0	65840	98760	164600
2005	0	0	0	65840	98760	164600
2006	0	0	0	65840	98760	164600
2007	0	0	0	65840	98760	164600
2008	0	0	0	65840	98760	164600
2009	0	0	0	65840	98760	164600
2010	0	0	0	65840	98760	164600

Demand Side Program: RESIDENTIAL INSULATION LOAN

DSM Type: CONSERVATION

Description: Encouraging the purchase and installation of insulation.
This would be accomplished using a direct loan program.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-0.068	KW per customer
Winter	-0.526	KW per customer
Spring	-0.186	KW per customer
Fall	-0.255	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-173.0	KWH per customer
Winter	-855.0	KWH per customer
Spring	-207.0	KWH per customer
Fall	-284.0	KWH per customer
Total annual	-1519	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RS CAT 4	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.00	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$0	per unit per year
Administration cost =	$0	$0	per year

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	3500	2002	0
1993	3500	2003	0
1994	3500	2004	0
1995	3500	2005	0
1996	3500	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders 1 5.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	175	3325	3500	175	3325	3500
1993	175	3325	3500	350	6650	7000
1994	175	3325	3500	525	9975	10500
1995	175	3325	3500	700	13300	14000
1996	175	3325	3500	875	16625	17500
1997	0	0	0	875	16625	17500
1998	0	0	0	875	16625	17500
1999	0	0	0	875	16625	17500
2000	0	0	0	875	16625	17500
2001	0	0	0	875	16625	17500
2002	0	0	0	875	16625	17500
2003	0	0	0	875	16625	17500
2004	0	0	0	875	16625	17500
2005	0	0	0	875	16625	17500
2006	0	0	0	875	16625	17500
2007	0	0	0	875	16625	17500
2008	0	0	0	875	16625	17500
2009	0	0	0	875	16625	17500
2010	0	0	0	875	16625	17500

Demand Side Program: INTERRUPTIBLE SERVICE

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 1992.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$1,145	$11,570	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing CO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (1996 and beyond; $135,115 in 1992 w/linear increase to 1996)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	50	2002	0
1993	50	2003	0
1994	50	2004	0
1995	50	2005	0
1996	50	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	50	50	0	50	50
1993	0	50	50	0	100	100
1994	0	50	50	0	150	150
1995	0	50	50	0	200	200
1996	0	50	50	0	250	250
1997	0	0	0	0	250	250
1998	0	0	0	0	250	250
1999	0	0	0	0	250	250
2000	0	0	0	0	250	250
2001	0	0	0	0	250	250
2002	0	0	0	0	250	250
2003	0	0	0	0	250	250
2004	0	0	0	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 1992

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 1992.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

Energy (KWH)			(OPTIONAL) Demand (KW)		
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$1,145	$11,570	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (1996 and beyond; $135,115 in 1992 w/linear increase to 1996)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	50	2002	0
1993	50	2003	0
1994	50	2004	0
1995	50	2005	0
1996	50	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units			Total Cumulative Units		
	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	50	50	0	50	50
1993	0	50	50	0	100	100
1994	0	50	50	0	150	150
1995	0	50	50	0	200	200
1996	0	50	50	0	250	250
1997	0	0	0	0	250	250
1998	0	0	0	0	250	250
1999	0	0	0	0	250	250
2000	0	0	0	0	250	250
2001	0	0	0	0	250	250
2002	0	0	0	0	250	250
2003	0	0	0	0	250	250
2004	0	0	0	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 1993

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 1993.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketi..g GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (1997 and beyond; $135,115 in 1993 w/linear increase to 1997)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	0	2002	0
1993	50	2003	0
1994	50	2004	0
1995	50	2005	0
1996	50	2006	0
1997	50	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units: Free Riders	Incremental Units: Non-Free Riders	Incremental Units: Total	Total Cumulative Units: Free Riders	Total Cumulative Units: Non-Free Riders	Total Cumulative Units: Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	50	50	0	50	50
1994	0	50	50	0	100	100
1995	0	50	50	0	150	150
1996	0	50	50	0	200	200
1997	0	50	50	0	250	250
1998	0	0	0	0	250	250
1999	0	0	0	0	250	250
2000	0	0	0	0	250	250
2001	0	0	0	0	250	250
2002	0	0	0	0	250	250
2003	0	0	0	0	250	250
2004	0	0	0	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 1994

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 1994.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (1998 and beyond; $135,115 in 1994 w/linear increase to 1998)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	0	2002	0
1993	0	2003	0
1994	50	2004	0
1995	50	2005	0
1996	50	2006	0
1997	50	2007	0
1998	50	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	50	50	0	50	50
1995	0	50	50	0	100	100
1996	0	50	50	0	150	150
1997	0	50	50	0	200	200
1998	0	50	50	0	250	250
1999	0	0	0	0	250	250
2000	0	0	0	0	250	250
2001	0	0	0	0	250	250
2002	0	0	0	0	250	250
2003	0	0	0	0	250	250
2004	0	0	0	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 1995

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 1995.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (1999 and beyond; $135,115 in 1995 w/linear increase to 1999)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	0	2002	0
1993	0	2003	0
1994	0	2004	0
1995	50	2005	0
1996	50	2006	0
1997	50	2007	0
1998	50	2008	0
1999	50	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	50	50	0	50	50
1996	0	50	50	0	100	100
1997	0	50	50	0	150	150
1998	0	50	50	0	200	200
1999	0	50	50	0	250	250
2000	0	0	0	0	250	250
2001	0	0	0	0	250	250
2002	0	0	0	0	250	250
2003	0	0	0	0	250	250
2004	0	0	0	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 1996

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 1996.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates
Energy Sales Price:	$0.00000	cents/kwh
Fuel Factor:	$0.01	per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010
fuel escal.	3.486%	per year thru 2010
Cust Credits	0.500%	per year thru 2010

These escalators are not yet updated

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (2000 and beyond; $135,115 in 1996 w/linear increase to 2000)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	0	2002	0
1993	0	2003	0
1994	0	2004	0
1995	0	2005	0
1996	50	2006	0
1997	50	2007	0
1998	50	2008	0
1999	50	2009	0
2000	50	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	50	50	0	50	50
1997	0	50	50	0	100	100
1998	0	50	50	0	150	150
1999	0	50	50	0	200	200
2000	0	50	50	0	250	250
2001	0	0	0	0	250	250
2002	0	0	0	0	250	250
2003	0	0	0	0	250	250
2004	0	0	0	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 1998

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 1998.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND – EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. I PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (2002 and beyond; $135,115 in 1998 w/linear increase to 2002)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	50
1992	0	2002	50
1993	0	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	50	2008	0
1999	50	2009	0
2000	50	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	50	50	0	50	50
1999	0	50	50	0	100	100
2000	0	50	50	0	150	150
2001	0	50	50	0	200	200
2002	0	50	50	0	250	250
2003	0	0	0	0	250	250
2004	0	0	0	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 2000

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 2000.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	

(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (2000 and beyond; $135,115 in 2000 w/linear increase to 2004)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	50
1992	0	2002	50
1993	0	2003	50
1994	0	2004	50
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	50	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	0	0	0	0	0
1999	0	0	0	0	0	0
2000	0	50	50	0	50	50
2001	0	50	50	0	100	100
2002	0	50	50	0	150	150
2003	0	50	50	0	200	200
2004	0	50	50	0	250	250
2005	0	0	0	0	250	250
2006	0	0	0	0	250	250
2007	0	0	0	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 2003

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 2003.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND -- EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	

(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (2007 and beyond; $135,115 in 2003 w/linear increase to 2007)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	0	2002	0
1993	0	2003	50
1994	0	2004	50
1995	0	2005	50
1996	0	2006	50
1997	0	2007	50
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	0	0	0	0	0
1999	0	0	0	0	0	0
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	50	50	0	50	50
2004	0	50	50	0	100	100
2005	0	50	50	0	150	150
2006	0	50	50	0	200	200
2007	0	50	50	0	250	250
2008	0	0	0	0	250	250
2009	0	0	0	0	250	250
2010	0	0	0	0	250	250

Demand Side Program: INTERRUPTIBLE SERVICE - START THE ADDITIONS IN 2006

DSM Type: INTERRUPTIBLE

Description: Interruptible Service (IS) is a program which purchases capacity, in the form of load removal, from non-residential customers. The majority of the customers are industrial. The program pays a monthly capacity credit for the right to require customers to interrupt load up to 150 hrs per year. Duke Power is restricted to requesting a maximum of 10 hrs per day of interruption. Each time a customer fails to comply, he is charged a penalty of $10.00 per KW. This set of LCIRP inputs is based upon a projected program capacity of 600 MW EID by the end of 1991 with the addition of 500 MW EID in 100 MW annual increments beginning in 2006.

Assumptions:

1. Unit Definition: EFFECTIVE INTERRUPTIBLE DEMAND – EID

2. Units per Average Customer: 2000 EID per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)

Peak reduction per unit

Spring	-1.000	kw/EID
Summer:	-1.000	kw/EID
Winter:	-1.000	kw/EID
Fall:	-1.000	kw/EID

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	25%	1.25%
Tot Line Loss:		4.90%
Failure Rate:	10%	(Failure to comply due to communications system malfunction or voluntary non-compliance)

System Peak Reduction
(Includes Line Loss and Failure Rate)

Spring	-1888.182	KW per customer
Summer	-1888.182	KW per customer
Winter	-1888.182	KW per customer
Fall	-1888.182	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)			(OPTIONAL) Demand (KW)	
Spring	0.0	KWH per customer	Spring	0.0	KW per customer
Summer	0.0	KWH per customer	Summer	0.0	KW per customer
Winter	0.0	KWH per customer	Winter	0.0	KW per customer
Fall	0.0	KWH per customer	Fall	0.0	KW per customer
Total annual	0	KWH per customer			

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RIDER IS	Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.486%	per year thru 2010	
fuel escal.	3.486%	per year thru 2010	These escalators are not yet updated
Cust Credits	0.500%	per year thru 2010	

7. PAYMENTS:

Monthly Bill Credit: $3.50 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$25,000	$1,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$400	per unit
Administration cost =	$0	$1,100	per customer

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$2,623.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$679.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 1% (2010; $135,115 in 2006 w/linear increase to 2010)
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$11,050.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c. Production Losses per Interruption	Unknown	
d. Extra facilities=	$110.00	per month

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	300	2001	0
1992	0	2002	0
1993	0	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	50
1997	0	2007	50
1998	0	2008	50
1999	0	2009	50
2000	0	2010	50

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	300	300
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	0	0	0	0	0
1999	0	0	0	0	0	0
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	50	50	0	50	50
2007	0	50	50	0	100	100
2008	0	50	50	0	150	150

Demand Side Program: STANDBY GENERATOR WITHOUT BACKFEED

DSM Type: INTERRUPTIBLE

Description: Customers operate on-site generators and shift all or a portion of their load to their generator and off our system.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-651.894	KW per customer
Winter	-651.894	KW per customer
Spring	-651.894	KW per customer
Fall	-651.894	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: Use proposed rates
Energy Sales Price: $0.00000 cents/kwh

Fuel Factor: $0.00 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS			
Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training =	$0.00	$0	per year
(consultants, materials, travel & training)			
Marketing Advertising =	$0	$0	per year
(brochures, promotional, air time)	0		
Marketing Development	$0	$0	per year
(demonstration, travel, misc.)			
Marketing GO Labor =	$0	$0	per year
Field sales labor	$0	$0	per unit
Administration cost =	$0	$0	per unit

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
	0	
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	43	2001	0
1992	0	2002	0
1993	0	2003	0
1994	0	2004	0
1995	0	2005	0
1996	0	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	43	43
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	0	0	0	0	0
1999	0	0	0	0	0	0
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	0	0	0	0	0	0

Demand Side Program: RESIDENTIAL WATER HEATER INSULATING BLANKET

DSM Type: CONSERVATION

Description: Encourages residential customers to improve water heater insulation by installing water heater blankets.

Assumptions:

1. Unit Definition: unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-0.039	KW per customer
Winter	-0.099	KW per customer
Spring	-0.081	KW per customer
Fall	-0.135	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-95.0	KWH per customer
Winter	-164.0	KWH per customer
Spring	-74.0	KWH per customer
Fall	-74.0	KWH per customer
Total annual	-407	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:		RS CAT 2	Use proposed rates	
Energy Sales Price:		$0.07925	cents/kwh	
Fuel Factor:		$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	3.49%	per year thru 2010	
fuel escal.	3.49%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$50,000.00	$10,000	per year
Marketing Advertising = (brochures, promotional, air time)	$165,000	$50,000	per year
Marketing Development (demonstration, travel, misc.)	$8,000	$0	per year
Marketing GO Labor =	$1,000	$1,000	per year
Field sales labor	$13	$13	per unit per year
Administration cost =	$10,000	$6,500	per year

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$13.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	20000	2002	0
1993	25000	2003	0
1994	25000	2004	0
1995	25000	2005	0
1996	25000	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	20000	20000	0	20000	20000
1993	0	25000	25000	0	45000	45000
1994	0	25000	25000	0	70000	70000
1995	0	25000	25000	0	95000	95000
1996	0	25000	25000	0	120000	120000
1997	0	0	0	0	120000	120000
1998	0	0	0	0	120000	120000
1999	0	0	0	0	120000	120000
2000	0	0	0	0	120000	120000
2001	0	0	0	0	120000	120000
2002	0	0	0	0	120000	120000
2003	0	0	0	0	120000	120000
2004	0	0	0	0	120000	120000
2005	0	0	0	0	120000	120000
2006	0	0	0	0	120000	120000
2007	0	0	0	0	120000	120000
2008	0	0	0	0	120000	120000
2009	0	0	0	0	120000	120000
2010	0	0	0	0	120000	120000

Demand Side Program: RESIDENTIAL HVAC TUNE-UP

DSM Type: CONSERVATION

Description: Encourages residential customers to identify and correct problems with their heat pump systems, thus improving efficiency, cost, and comfort.

Assumptions:

1. Unit Definition: Unit

2. Units per Average Customer: 1 unit per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-0.652	KW per customer
Winter	-0.405	KW per customer
Spring	-0.064	KW per customer
Fall	-0.120	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-478.0	KWH per customer
Winter	-564.0	KWH per customer
Spring	-86.0	KWH per customer
Fall	-114.0	KWH per customer
Total annual	-1242	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	RE CAT 2	Use proposed rates	
Energy Sales Price:	$0.07137	cents/kwh	
Fuel Factor:	$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$400.00	per unit
Monthly Bill Credit:	$0.00	per month per unit
Rate Incentives:	$0.00	per kwh per month

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$75,000.00	$10,000	per year
Marketing Advertising = (brochures, promotional, air time)	$122,550	$50,000	per year
Marketing Development (demonstration, travel, misc.)	$25,000	$0	per year
Marketing GO Labor =	$2,575	$2,000	per year
Field sales labor	$12	$12	per unit per year
Administration cost =	$10,000	$5,000	per year

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$400.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	0	2002	0
1993	2500	2003	0
1994	6000	2004	0
1995	10000	2005	0
1996	20000	2006	0
1997	40000	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units			Total Cumulative Units		
	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	0	2500	2500	0	2500	2500
1994	0	6000	6000	0	8500	8500
1995	0	10000	10000	0	18500	18500
1996	0	20000	20000	0	38500	38500
1997	0	40000	40000	0	78500	78500
1998	0	0	0	0	78500	78500
1999	0	0	0	0	78500	78500
2000	0	0	0	0	78500	78500
2001	0	0	0	0	78500	78500
2002	0	0	0	0	78500	78500
2003	0	0	0	0	78500	78500
2004	0	0	0	0	78500	78500
2005	0	0	0	0	78500	78500
2006	0	0	0	0	78500	78500
2007	0	0	0	0	78500	78500
2008	0	0	0	0	78500	78500
2009	0	0	0	0	78500	78500
2010	0	0	0	0	78500	78500

Demand Side Program: HIGH EFFICIENCY CHILLERS FOR AIR CONDITIONING

DSM Type: CONSERVATION

Description: Promote the use of high efficient, central chillers in both the new and existing markets. These units will reduce peak demands and lower cooling energy consumption.

Assumptions:

1. Unit Definition: CHILLER: 250 tons

2. Units per Average Customer: 1 chiller per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction
(Includes Line Loss)

Summer	-70.491	KW per customer
Winter	-0.007	KW per customer
Spring	-50.522	KW per customer
Fall	-50.522	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-111810.0	KWH per customer
Winter	-4961.0	KWH per customer
Spring	-20717.0	KWH per customer
Fall	-20696.0	KWH per customer
Total annual	-158184	KWH Per Customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: OPT, GA, I, G Use proposed rates
Energy Sales Price: $0.06117 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $25,000.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$1,000.00	$1,000	per year
Marketing Advertising = (brochures, promotional, air time)	$12,715 0	$11,570	per year
Marketing Development (demonstration, travel, misc.)	$2,000	$2,000	per year
Marketing GO Labor =	$2,000	$2,000	per year
Field sales labor	$96	$96	per unit
Administration cost =	$35	$35	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $12,500.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	90
1992	40	2002	90
1993	40	2003	80
1994	60	2004	70
1995	70	2005	50
1996	80	2006	40
1997	100	2007	40
1998	100	2008	40
1999	100	2009	40
2000	100	2010	40

12. Free Riders: 10.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	4	36	40	4	36	40
1993	4	36	40	8	72	80
1994	6	54	60	14	126	140
1995	7	63	70	21	189	210
1996	8	72	80	29	261	290
1997	10	90	100	39	351	390
1998	10	90	100	49	441	490
1999	10	90	100	59	531	590
2000	10	90	100	69	621	690
2001	9	81	90	78	702	780
2002	9	81	90	87	783	870
2003	8	72	80	95	855	950
2004	7	63	70	102	918	1020
2005	5	45	50	107	963	1070
2006	4	36	40	111	999	1110
2007	4	36	40	115	1035	1150
2008	4	36	40	119	1071	1190
2009	4	36	40	123	1107	1230
2010	4	36	40	127	1143	1270

Demand Side Program: HIGH EFFICIENCY UNITARY EQUIPMENT FOR AIR CONDITIONING

DSM Type: CONSERVATION

Description: Promote the use of high efficient, single phase unitary air conditioners in both the new and existing markets. These units will reduce peak demands and lower cooling energy cc nsumption.

Assumptions:

1. Unit Definition: A/C UNIT: 3 TON

2. Units per Average Customer: 1.5 A/C units per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-1.193	KW per customer
Winter	0.000	KW per customer
Spring	-0.688	KW per customer
Fall	-0.688	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-530.3	KWH per customer
Winter	-32.7	KWH per customer
Spring	-144.9	KWH per customer
Fall	-94.8	KWH per customer
Total annual	-802.7	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: G, GA, I — Use proposed rates
Energy Sales Price: $0.09599 cents/kwh

Fuel Factor: $0.01 per kwh — Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $250.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$5,000.00	$5,000	per year
Marketing Advertising = (brochures, promotional, air time)	$39,400 0	$33,000	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$0	$0	per year
Field sales labor	$43	$43	per unit
Administration cost =	$23	$23	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%

(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $450.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	2000
1992	1100	2002	2000
1993	1375	2003	2000
1994	1650	2004	2000
1995	1925	2005	2000
1996	2000	2006	2000
1997	2000	2007	2000
1998	2000	2008	2000
1999	2000	2009	2000
2000	2000	2010	2000

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	1100	1100	0	1100	1100
1993	0	1375	1375	0	2475	2475
1994	0	1650	1650	0	4125	4125
1995	0	1925	1925	0	6050	6050
1996	0	2000	2000	0	8050	8050
1997	0	2000	2000	0	10050	10050
1998	0	2000	2000	0	12050	12050
1999	0	2000	2000	0	14050	14050
2000	0	2000	2000	0	16050	16050
2001	0	2000	2000	0	18050	18050
2002	0	2000	2000	0	20050	20050
2003	0	2000	2000	0	22050	22050
2004	0	2000	2000	0	24050	24050
2005	0	2000	2000	0	26050	26050
2006	0	2000	2000	0	28050	28050
2007	0	2000	2000	0	30050	30050
2008	0	2000	2000	0	32050	32050
2009	0	2000	2000	0	34050	34050
2010	0	2000	2000	0	36050	36050

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
ELECTRIC HEATING - EXISTING MARKET

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the existing customer market. This option is designed for customers with electric heating systems.

Assumptions:

1. Unit Definition: CUSTOMER

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction
(Includes Line Loss)

Summer	-19.285	KW per customer
Winter	0.000	KW per customer
Spring	-18.459	KW per customer
Fall	-18.459	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-26128.6	KWH per customer
Winter	0.0	KWH per customer
Spring	-12835.0	KWH per customer
Fall	-12754.3	KWH per customer
Total annual	-51717.9	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: GA Use proposed rates
Energy Sales Price: $0.06247 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $3,642.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$11,850.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$13,907.68 0	$12,606	per year
Marketing Development (demonstration, travel, misc.)	$5,653	$5,083	per year
Marketing GO Labor =	$22,366	$20,333	per year
Field sales labor	$128	$128	per unit
Administration cost =	$81	$81	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $25,158.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	733
1992	0	2002	733
1993	733	2003	733
1994	733	2004	733
1995	733	2005	733
1996	733	2006	733
1997	733	2007	0
1998	733	2008	0
1999	733	2009	0
2000	733	2010	0

12. Free Riders: 5.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	36.65	696.35	733	37	696	733
1994	36.65	696.35	733	73	1393	1466
1995	36.65	696.35	733	110	2089	2199
1996	36.65	696.35	733	147	2785	2932
1997	36.65	696.35	733	183	3482	3665
1998	36.65	696.35	733	220	4178	4398
1999	36.65	696.35	733	257	4874	5131
2000	36.65	696.35	733	293	5571	5864
2001	36.65	696.35	733	330	6267	6597
2002	36.65	696.35	733	366	6964	7330
2003	36.65	696.35	733	403	7660	8063
2004	36.65	696.35	733	440	8356	8796
2005	36.65	696.35	733	476	9053	9529
2006	36.65	696.35	733	513	9749	10262
2007	0	0	0	513	9749	10262
2008	0	0	0	513	9749	10262
2009	0	0	0	513	9749	10262
2010	0	0	0	513	9749	10262

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
ELECTRIC HEATING - NEW MARKET

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the new customer market. This option is designed for customers with electric heating systems.

Assumptions:

1. Unit Definition: CUSTOMER

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-19.285	KW per customer
Winter	0.000	KW per customer
Spring	-18.459	KW per customer
Fall	-18.459	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-26128.6	KWH per customer
Winter	0.0	KWH per customer
Spring	-12835.0	KWH per customer
Fall	-12754.3	KWH per customer
Total annual	-51717.9	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: GA Use proposed rates
Energy Sales Price: $0.06247 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $3,642.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$5,739.08	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$6,735.64 0	$6,105	per year
Marketing Development (demonstration, travel, misc.)	$2,738	$2,462	per year
Marketing GO Labor =	$10,832	$9,847	per year
Field sales labor	$128	$128	per unit
Administration cost =	$81	$81	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $5,031.60 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	355
1992	0	2002	355
1993	355	2003	355
1994	355	2004	355
1995	355	2005	355
1996	355	2006	355
1997	355	2007	0
1998	355	2008	0
1999	355	2009	0
2000	355	2010	0

12. Free Riders: 10.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	35.5	319.5	355	36	320	355
1994	35.5	319.5	355	71	639	710
1995	35.5	319.5	355	107	959	1065
1996	35.5	319.5	355	142	1278	1420
1997	35.5	319.5	355	178	1598	1775
1998	35.5	319.5	355	213	1917	2130
1999	35.5	319.5	355	249	2237	2485
2000	35.5	319.5	355	284	2556	2840
2001	35.5	319.5	355	320	2876	3195
2002	35.5	319.5	355	355	3195	3550
2003	35.5	319.5	355	391	3515	3905
2004	35.5	319.5	355	426	3834	4260
2005	35.5	319.5	355	462	4154	4615
2006	35.5	319.5	355	497	4473	4970
2007	0	0	0	497	4473	4970
2008	0	0	0	497	4473	4970
2009	0	0	0	497	4473	4970
2010	0	0	0	497	4473	4970

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
FOSSIL HEATING - EXISTING MARKET

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the existing non-residential market. This option is designed for customers with fossil heating systems.

Assumptions:

1. Unit Definition: CUSTOMER

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-12.614	KW per customer
Winter	-4.448	KW per customer
Spring	-12.060	KW per customer
Fall	-12.060	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-17085.5	KWH per customer
Winter	-15644.5	KWH per customer
Spring	-8339.9	KWH per customer
Fall	-8393.1	KWH per customer
Total annual	-49463	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: G, I — Use proposed rates
Energy Sales Price: $0.06731 cents/kwh

Fuel Factor: $0.01 per kwh — Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $2,382.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$17,314.25	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$20,321 0	$18,419	per year
Marketing Development (demonstration, travel, misc.)	$8,259	$7,427	per year
Marketing GO Labor =	$32,680	$29,709	per year
Field sales labor	$128	$128	per unit
Administration cost =	$81	$81	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $17,938.20 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	1071
1992	0	2002	1071
1993	1071	2003	1071
1994	1071	2004	1071
1995	1071	2005	1071
1996	1071	2006	1071
1997	1071	2007	0
1998	1071	2008	0
1999	1071	2009	0
2000	1071	2010	0

12. Free Riders: 5.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	53.55	1017.45	1071	54	1017	1071
1994	53.55	1017.45	1071	107	2035	2142
1995	53.55	1017.45	1071	161	3052	3213
1996	53.55	1017.45	1071	214	4070	4284
1997	53.55	1017.45	1071	268	5087	5355
1998	53.55	1017.45	1071	321	6105	6426
1999	53.55	1017.45	1071	375	7122	7497
2000	53.55	1017.45	1071	428	8140	8568
2001	53.55	1017.45	1071	482	9157	9639
2002	53.55	1017.45	1071	535	10175	10710
2003	53.55	1017.45	1071	589	11192	11781
2004	53.55	1017.45	1071	643	12209	12852
2005	53.55	1017.45	1071	696	13227	13923
2006	53.55	1017.45	1071	750	14244	14994
2007	0	0	0	750	14244	14994
2008	0	0	0	750	14244	14994
2009	0	0	0	750	14244	14994
2010	0	0	0	750	14244	14994

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
FOSSIL HEATING - NEW MARKET

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the new non-residential market. This option is designed for customers with fossil heating systems.

Assumptions:

1. Unit Definition: CUSTOMER

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-12.614	KW per customer
Winter	-4.448	KW per customer
Spring	-12.060	KW per customer
Fall	-12.060	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-17085.5	KWH per customer
Winter	-15644.5	KWH per customer
Spring	-8339.9	KWH per customer
Fall	-8393.1	KWH per customer
Total annual	-49463	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	G, I		Use proposed rates
Energy Sales Price:		$0.06731	cents/kwh
Fuel Factor:		$0.01	per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $2,382.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$17,605.25	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$20,662 0	$18,729	per year
Marketing Development (demonstration, travel, misc.)	$8,398	$7,552	per year
Marketing GO Labor =	$33,229	$30,208	per year
Field sales labor	$128	$128	per unit
Administration cost =	$81	$81	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%

(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $3,587.64 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	1089
1992	0	2002	1089
1993	1089	2003	1089
1994	1089	2004	1089
1995	1089	2005	1089
1996	1089	2006	1089
1997	1089	2007	0
1998	1089	2008	0
1999	1089	2009	0
2000	1089	2010	0

12. Free Riders: 10.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	108.9	980.1	1089	109	980	1089
1994	108.9	980.1	1089	218	1960	2178
1995	108.9	980.1	1089	327	2940	3267
1996	108.9	980.1	1089	436	3920	4356
1997	108.9	980.1	1089	545	4901	5445
1998	108.9	980.1	1089	653	5881	6534
1999	108.9	980.1	1089	762	6861	7623
2000	108.9	980.1	1089	871	7841	8712
2001	108.9	980.1	1089	980	8821	9801
2002	108.9	980.1	1089	1089	9801	10890
2003	108.9	980.1	1089	1198	10781	11979
2004	108.9	980.1	1089	1307	11761	13068
2005	108.9	980.1	1089	1416	12741	14157
2006	108.9	980.1	1089	1525	13721	15246
2007	0	0	0	1525	13721	15246
2008	0	0	0	1525	13721	15246
2009	0	0	0	1525	13721	15246
2010	0	0	0	1525	13721	15246

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
OPT SCHEDULE - EXISTING MARKET

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the existing non-residential market. This option is designed for customers on rate schedule OPT.

Assumptions:

1. Unit Definition: CUSTOMER

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-24.446	KW per customer
Winter	-14.717	KW per customer
Spring	-24.446	KW per customer
Fall	-24.446	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-48218.2	KWH per customer
Winter	-47910.8	KWH per customer
Spring	-24150.0	KWH per customer
Fall	-24167.0	KWH per customer
Total annual	-144446	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	OPT		Use proposed rates
Energy Sales Price:		$0.05426	cents/kwh
Fuel Factor:		$0.01	per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $4,500.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$4,672.10	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$5,483 0	$4,970	per year
Marketing Development (demonstration, travel, misc.)	$2,229	$2,004	per year
Marketing GO Labor =	$8,818	$8,017	per year
Field sales labor	$128	$128	per unit
Administration cost =	$81	$81	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%

(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $30,426.90 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	289
1992	0	2002	289
1993	289	2003	289
1994	289	2004	289
1995	289	2005	289
1996	289	2006	289
1997	289	2007	0
1998	289	2008	0
1999	289	2009	0
2000	289	2010	0

12. Free Riders: 5.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	14.45	274.55	289	14	275	289
1994	14.45	274.55	289	29	549	578
1995	14.45	274.55	289	43	824	867
1996	14.45	274.55	289	58	1098	1156
1997	14.45	274.55	289	72	1373	1445
1998	14.45	274.55	289	87	1647	1734
1999	14.45	274.55	289	101	1922	2023
2000	14.45	274.55	289	116	2196	2312
2001	14.45	274.55	289	130	2471	2601
2002	14.45	274.55	289	144	2746	2890
2003	14.45	274.55	289	159	3020	3179
2004	14.45	274.55	289	173	3295	3468
2005	14.45	274.55	289	188	3569	3757
2006	14.45	274.55	289	202	3844	4046
2007	0	0	0	202	3844	4046
2008	0	0	0	202	3844	4046
2009	0	0	0	202	3844	4046
2010	0	0	0	202	3844	4046

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
OPT SCHEDULE - NEW MARKET

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the new non-residential market. This option is designed for customers on rate schedule OPT.

Assumptions:

1. Unit Definition: CUSTOMER

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-24.446	KW per customer
Winter	-14.717	KW per customer
Spring	-24.446	KW per customer
Fall	-24.446	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-48218.2	KWH per customer
Winter	-47910.8	KWH per customer
Spring	-24150.0	KWH per customer
Fall	-24167.0	KWH per customer
Total annual	-144446	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	OPT		Use proposed rates	
Energy Sales Price:		$0.05426	cents/kwh	
Fuel Factor:		$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $4,500.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$1,099.32	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$1,290 0	$1,169	per year
Marketing Development (demonstration, travel, misc.)	$524	$472	per year
Marketing GO Labor =	$2,075	$1,886	per year
Field sales labor	$128	$128	per unit
Administration cost =	$81	$81	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $6,085.38 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	68
1992	0	2002	68
1993	68	2003	68
1994	68	2004	68
1995	68	2005	68
1996	68	2006	68
1997	68	2007	0
1998	68	2008	0
1999	68	2009	0
2000	68	2010	0

12. Free Riders: 10.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	6.8	61.2	68	7	61	68
1994	6.8	61.2	68	14	122	136
1995	6.8	61.2	68	20	184	204
1996	6.8	61.2	68	27	245	272
1997	6.8	61.2	68	34	306	340
1998	6.8	61.2	68	41	367	408
1999	6.8	61.2	68	48	428	476
2000	6.8	61.2	68	54	490	544
2001	6.8	61.2	68	61	551	612
2002	6.8	61.2	68	68	612	680
2003	6.8	61.2	68	75	673	748
2004	6.8	61.2	68	82	734	816
2005	6.8	61.2	68	88	796	884
2006	6.8	61.2	68	95	857	952
2007	0	0	0	95	857	952
2008	0	0	0	95	857	952
2009	0	0	0	95	857	952
2010	0	0	0	95	857	952

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
HIGH SCENARIO LIGHTING - ELECTRIC HEATING

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the new and existing customer market. This option is designed for customers with electric heating systems.

Assumptions:

1. Unit Definition: 1 KW

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-1.135	KW per customer
Winter	0.000	KW per customer
Spring	-1.086	KW per customer
Fall	-1.086	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-1472.0	KWH per customer
Winter	0.0	KWH per customer
Spring	-755.4	KWH per customer
Fall	-750.7	KWH per customer
Total annual	-2978.1	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: GA Use proposed rates
Energy Sales Price: $0.06247 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $500.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$52,014.90	$5,000	per year
Marketing Advertising = (brochures, promotional, air time)	$61,047.00 0	$55,335	per year
Marketing Development (demonstration, travel, misc.)	$133,153	$90,083	per year
Marketing GO Labor =	$76,500	$76,500	per year
Field sales labor	$16	$16	per unit
Administration cost =	$5	$5	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes
a. Installation and equipment costs= $500.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	41318
1992	0	2002	41318
1993	0	2003	41318
1994	0	2004	41318
1995	41318	2005	41318
1996	41318	2006	41318
1997	41318	2007	41318
1998	41318	2008	41318
1999	41318	2009	41318
2000	41318	2010	41318

12. Free Riders: 2.50% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	1032.95	40285.05	41318	1033	40285	41318
1996	1032.95	40285.05	41318	2066	80570	82636
1997	1032.95	40285.05	41318	3099	120855	123954
1998	1032.95	40285.05	41318	4132	161140	165272
1999	1032.95	40285.05	41318	5165	201425	206590
2000	1032.95	40285.05	41318	6198	241710	247908
2001	1032.95	40285.05	41318	7231	281995	289226
2002	1032.95	40285.05	41318	8264	322280	330544
2003	1032.95	40285.05	41318	9297	362565	371862
2004	1032.95	40285.05	41318	10330	402851	413180
2005	1032.95	40285.05	41318	11362	443136	454498
2006	1032.95	40285.05	41318	12395	483421	495816
2007	1032.95	40285.05	41318	13428	523706	537134
2008	1032.95	40285.05	41318	14461	563991	578452
2009	1032.95	40285.05	41318	15494	604276	619770

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING
HIGH SCENARIO LIGHTING - FOSSIL HEATING

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the new and existing non-residential market. This option is designed for customers with fossil heating systems.

Assumptions:

1. Unit Definition: 1 KW

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction
(Includes Line Loss)

Summer	-1.136	KW per customer
Winter	-0.401	KW per customer
Spring	-1.086	KW per customer
Fall	-1.086	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-1471.6	KWH per customer
Winter	-1517.3	KWH per customer
Spring	-751.3	KWH per customer
Fall	-756.1	KWH per customer
Total annual	-4496.39	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: G, I — Use proposed rates
Energy Sales Price: $0.06731 cents/kwh

Fuel Factor: $0.01 per kwh — Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $500.00 per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$52,014.90	$5,000	per year
Marketing Advertising = (brochures, promotional, air time)	$61,047 0	$55,335	per year
Marketing Development (demonstration, travel, misc.)	$135,759	$92,427	per year
Marketing GO Labor =	$76,500	$76,500	per year
Field sales labor	$16	$16	per unit
Administration cost =	$5	$5	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%

(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $500.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	41318
1992	0	2002	41318
1993	0	2003	41318
1994	0	2004	41318
1995	41318	2005	41318
1996	41318	2006	41318
1997	41318	2007	41318
1998	41318	2008	41318
1999	41318	2009	41318
2000	41318	2010	41318

12. Free Riders: 2.50% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	1032.95	40285.05	41318	1033	40285	41318
1996	1032.95	40285.05	41318	2066	80570	82636
1997	1032.95	40285.05	41318	3099	120855	123954
1998	1032.95	40285.05	41318	4132	161140	165272
1999	1032.95	40285.05	41318	5165	201425	206590
2000	1032.95	40285.05	41318	6198	241710	247908
2001	1032.95	40285.05	41318	7231	281995	289226
2002	1032.95	40285.05	41318	8264	322280	330544
2003	1032.95	40285.05	41318	9297	362565	371862
2004	1032.95	40285.05	41318	10330	402851	413180
2005	1032.95	40285.05	41318	11362	443136	454498
2006	1032.95	40285.05	41318	12395	483421	495816
2007	1032.95	40285.05	41318	13428	523706	537134
2008	1032.95	40285.05	41318	14461	563991	578452
2009	1032.95	40285.05	41318	15494	604276	619770

Demand Side Program: NON-RESIDENTIAL HIGH EFFICIENCY INDOOR LIGHTING - HIGH SCENARIO LIGHTING - OPT SCHEDULE

DSM Type: CONSERVATION

Description: Promote the use of high efficient lighting technologies and systems in the new and existing non-residential market. This option is designed for customers on rate schedule OPT.

Assumptions:

1. Unit Definition: 1 KW

2. Units per Average Customer: 1

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction (Includes Line Loss)

Summer	-1.136	KW per customer
Winter	-0.654	KW per customer
Spring	-1.086	KW per customer
Fall	-1.086	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-2143.0	KWH per customer
Winter	-2217.2	KWH per customer
Spring	-1073.3	KWH per customer
Fall	-1074.1	KWH per customer
Total annual	-6507.66	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:	OPT		Use proposed rates	
Energy Sales Price:		$0.05426	cents/kwh	
Fuel Factor:		$0.01	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $500.00 per unit

8. DUKE COSTS (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$18,358.20	$5,000	per year
Marketing Advertising = (brochures, promotional, air time)	$21,546 0	$19,530	per year
Marketing Development (demonstration, travel, misc.)	$47,229	$32,004	per year
Marketing GO Labor =	$27,000	$27,000	per year
Field sales labor	$16	$16	per unit
Administration cost =	$5	$5	per unit

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes
a. Installation and equipment costs= $500.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	14583
1992	0	2002	14583
1993	0	2003	14583
1994	0	2004	14583
1995	14583	2005	14583
1996	14583	2006	14583
1997	14583	2007	14583
1998	14583	2008	14583
1999	14583	2009	14583
2000	14583	2010	14583

12. Free Riders: 2.50% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	0	0	0	0	0	0
1995	364.575	14218.425	14583	365	14218	14583
1996	364.575	14218.425	14583	729	28437	29166
1997	364.575	14218.425	14583	1094	42655	43749
1998	364.575	14218.425	14583	1458	56874	58332
1999	364.575	14218.425	14583	1823	71092	72915
2000	364.575	14218.425	14583	2187	85311	87498
2001	364.575	14218.425	14583	2552	99529	102081
2002	364.575	14218.425	14583	2917	113747	116664
2003	364.575	14218.425	14583	3281	127966	131247
2004	364.575	14218.425	14583	3646	142184	145830
2005	364.575	14218.425	14583	4010	156403	160413
2006	364.575	14218.425	14583	4375	170621	174996
2007	364.575	14218.425	14583	4739	184840	189579
2008	364.575	14218.425	14583	5104	199058	204162
2009	364.575	14218.425	14583	5469	213276	218745
2010	364.575	14218.425	14583	5833	227495	233328

Demand Side Program: MOTOR SYSTEMS - 20% PENETRATION - $6 PER HORSEPOWER

DSM Type: CONSERVATION

Description: Encourages non-residential and non-resale customers to purchase and use energy efficient motors and motor drives. Customers will be encouraged to change-out motors on failure (replacement) or to specify in new equipment.

Assumptions:

1. Unit Definition: Motor (assume 25 HP typical)

2. Units per Average Customer: 3 motors changed per customer contact

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	50%	2.50%
Tot Line Loss:		6.15%

System Peak Reduction (Includes Line Loss)

Summer	-1.194	KW per customer
Winter	-0.986	KW per customer
Spring	-0.986	KW per customer
Fall	-0.986	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-2590	KWH per customer
Winter	-3989	KWH per customer
Spring	0	KWH per customer
Fall	0	KWH per customer
Total annual	-6563	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: GA,I,OPT,PG&IP (1990 Avg industrial + 10%)
Energy Sales Price: $0.04978 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	3.70%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $150.00 per unit ($6/HP)

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$16,640.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$62,000	$62,000	per year
Marketing Development (demonstration, travel, misc.)	$40,000	$2,000	per year
Marketing GO Labor =	$30,000	$30,000	per year
Field sales labor (sizing, verification, calcs, etc.)	$160,000	$48	per customer rebate
Administration cost =	$0	$35	per rebate check

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$425.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	35,697
1992	0	2002	35,697
1993	0	2003	35,697
1994	35,697	2004	35,697
1995	35,697	2005	0
1996	35,697	2006	0
1997	35,697	2007	0
1998	35,697	2008	0
1999	35,697	2009	0
2000	35,697	2010	0

12. Free Riders: 42.86% customers annually.

13. Overhead Multiplier for Fringe Benefits & Tax 26.56%

14. Demand reduction at 3/4 loading: -0.625 kw

15. Typical annual usage (hours/year): (3,337) 3,500 hours/year

16. Summer non-coincident demand factor: 0.81124

17. Winter non-coincident demand factor: 0.66984

18. Diversity factor: 60% (adjustment for load profile & multipliers)

19. Motor life: 12 Years (typical)

20. Program life will be 11 years, after that customers will voluntarily replace with energy efficient motors.

TOTAL CUSTOMERS OR UNITS

Year	Incremental Customers: Free Riders	Incremental Customers: Non-Free Riders	Incremental Customers: Total	Total Cumulative Customers: Free Riders	Total Cumulative Customers: Non-Free Riders	Total Cumulative Customers: Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	15,299	20,398	35,697	15,299	20,398	35,697
1995	15,299	20,398	35,697	30,597	40,796	71,393
1996	15,299	20,398	35,697	45,896	61,194	107,090
1997	15,299	20,398	35,697	61,194	81,592	142,787
1998	15,299	20,398	35,697	76,493	101,991	178,483
1999	15,299	20,398	35,697	91,791	122,389	214,180
2000	15,299	20,398	35,697	107,090	142,787	249,877
2001	15,299	20,398	35,697	122,389	163,185	285,574
2002	15,299	20,398	35,697	137,687	183,583	321,270
2003	15,299	20,398	35,697	152,986	203,981	356,967
2004	15,299	20,398	35,697	168,284	224,379	392,664
2005	0	0	0	168,284	224,379	392,664
2006	0	0	0	168,284	224,379	392,664
2007	0	0	0	168,284	224,379	392,664
2008	0	0	0	168,284	224,379	392,664
2009	0	0	0	168,284	224,379	392,664
2010	0	0	0	168,284	224,379	392,664

Demand Side Program: MOTOR SYSTEMS - 50% PENETRATION - $12 PER HORSEPOWER

DSM Type: CONSERVATION

Description: Encourages non-residential and non-resale customers to purchase and use energy efficient motors and motor drives. Customers will be encouraged to change-out motors on failure (replacement) or to specify in new equipment.

Assumptions:

1. Unit Definition: Motor (assume 25 HP typical)

2. Units per Average Customer: 3.5 motors changed per customer contact

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	50%	2.50%
Tot Line Loss:		6.15%

	System Peak Reduction (Includes Line Loss)	
Summer	-1.393	KW per customer
Winter	-1.150	KW per customer
Spring	-1.150	KW per customer
Fall	-1.150	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-3022	KWH per customer
Winter	-4654	KWH per customer
Spring	0	KWH per customer
Fall	0	KWH per customer
Total annual	-7656	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: GA,I,OPT,PG&IP (1990 Avg industrial + 10%)
Energy Sales Price: $0.04978 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	3.70%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $300.00 per unit ($12/HP)

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$16,640.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$62,000	$62,000	per year
Marketing Development (demonstration, travel, misc.)	$40,000	$2,000	per year
Marketing GO Labor =	$30,000	$30,000	per year
Field sales labor (sizing, verification, calcs, etc.)	$160,000	$48	per customer rebate
Administration cost =	$0	$35	per rebate check

Distribution Costs

a. Installation (Capital Costs)		
Material Costs =	$0.00	per unit
Labor Costs =	$0.00	per unit
b. Annual Equipment Maint. (O & M) =	$0.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$425.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	56,823
1992	0	2002	56,823
1993	0	2003	56,823
1994	56,823	2004	56,823
1995	56,823	2005	0
1996	56,823	2006	0
1997	56,823	2007	0
1998	56,823	2008	0
1999	56,823	2009	0
2000	56,823	2010	0

12. Free Riders: 23.08% customers annually.

13. Overhead Multiplier for Fringe Benefits & Tax 26.56%

14. Demand reduction at 3/4 loading: -0.625 kw

15. Typical annual usage (hours/year): (3,337) 3,500 hours/year

16. Summer non-coincident demand factor: 0.81124

17. Winter non-coincident demand factor: 0.66984

18. Diversity factor: 60% (adjustment for load profile & multiplier)

19. Motor life: 12 Years (typical)

20. Program life will be 11 years, after that customers will voluntarily replace with energy efficient motors.

TOTAL CUSTOMERS OR UNITS

Year	Incremental Customers			Total Cumulative Customers		
	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	13,113	43,710	56,823	13,113	43,710	56,823
1995	13,113	43,710	56,823	26,226	87,420	113,647
1996	13,113	43,710	56,823	39,339	131,131	170,470
1997	13,113	43,710	56,823	52,452	174,841	227,293
1998	13,113	43,710	56,823	65,565	218,551	284,116
1999	13,113	43,710	56,823	78,678	262,261	340,940
2000	13,113	43,710	56,823	91,791	305,972	397,763
2001	13,113	43,710	56,823	104,905	349,682	454,586
2002	13,113	43,710	56,823	118,018	393,392	511,410
2003	13,113	43,710	56,823	131,131	437,102	568,233
2004	13,113	43,710	56,823	144,244	480,813	625,056
2005	0	0	0	144,244	480,813	625,056
2006	0	0	0	144,244	480,813	625,056
2007	0	0	0	144,244	480,813	625,056
2008	0	0	0	144,244	480,813	625,056
2009	0	0	0	144,244	480,813	625,056
2010	0	0	0	144,244	480,813	625,056

Demand Side Program: MOTOR SYSTEMS - 80% PENETRATION - $25 PER HORSEPOWER

DSM Type: CONSERVATION

Description: Encourages non-residential and non-resale customers to purchase and use energy efficient motors and motor drives. Customers will be encouraged to change-out motors on failure (replacement) or to specify in new equipment.

Assumptions:

1. Unit Definition: Motor (assume 25 HP typical)

2. Units per Average Customer: 4 motors changed per customer contact

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	50%	2.50%
Tot Line Loss:		6.15%

	System Peak Reduction (Includes Line Loss)	
Summer	-1.592	KW per customer
Winter	-1.315	KW per customer
Spring	-1.315	KW per customer
Fall	-1.315	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	-3454	KWH per customer
Winter	-5318	KWH per customer
Spring	0	KWH per customer
Fall	0	KWH per customer
Total annual	-8750	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: GA,I,OPT,PG&IP (1990 Avg industrial + 10%)
Energy Sales Price: $0.04978 cents/kwh

Fuel Factor: $0.01 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	3.70%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $625.00 per unit ($25/HP)

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$16,640.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$62,000	$62,000	per year
Marketing Development (demonstration, travel, misc.)	$40,000	$2,000	per year
Marketing GO Labor =	$30,000	$30,000	per year
Field sales labor (sizing, verification, calcs, etc.)	$160,000	$48	per customer rebate
Administration cost =	$0	$35	per rebate check

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $425.00 per unit

b. Annual Maintenance cost changes = $0.00 per unit per year

c. per unit per year

d. Extra facilities=

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	72,668
1992	0	2002	72,668
1993	0	2003	72,668
1994	72,668	2004	72,668
1995	72,668	2005	0
1996	72,668	2006	0
1997	72,668	2007	0
1998	72,668	2008	0
1999	72,668	2009	0
2000	72,668	2010	0

12. Free Riders: 15.79% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

14. Demand reduction at 3/4 loading: -0.625 kw

15. Typical annual usage (hours/year): (3,337) 3,500 hours/year

16. Summer non-coincident demand factor: 0.81124

17. Winter non-coincident demand factor: 0.66984

18. Diversity factor: 60% (adjustment for laod profile & multiplier)

19. Motor life: 12 Years (typical)

20. Program life will be 11 years, after that customers will voluntarily replace with energy efficient motors.

TOTAL CUSTOMERS OR UNITS

	Incremental Customers			Total Cumulative Customers		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	0	0	0	0	0
1993	0	0	0	0	0	0
1994	11,474	61,194	72,668	11,474	61,194	72,668
1995	11,474	61,194	72,668	22,948	122,389	145,337
1996	11,474	61,194	72,668	34,422	183,583	218,005
1997	11,474	61,194	72,668	45,896	244,777	290,673
1998	11,474	61,194	72,668	57,370	305,972	363,341
1999	11,474	61,194	72,668	68,844	367,166	436,010
2000	11,474	61,194	72,668	80,318	428,360	508,678
2001	11,474	61,194	72,668	91,791	489,555	581,346
2002	11,474	61,194	72,668	103,265	550,749	654,014
2003	11,474	61,194	72,668	114,739	611,943	726,683
2004	11,474	61,194	72,668	126,213	673,138	799,351
2005	0	0	0	126,213	673,138	799,351
2006	0	0	0	126,213	673,138	799,351
2007	0	0	0	126,213	673,138	799,351
2008	0	0	0	126,213	673,138	799,351
2009	0	0	0	126,213	673,138	799,351

Demand Side Program: STANDBY GENERATOR WITH BACKFEED - 500KW/CUSTOMER EXPORTED

DSM Type: INTERRUPTIBLE

Description: Customers operate on-site generators in parallel to our system and if their load is less than the generator capacity, backfeed the remainder of the capacity onto our system. This option examines only the backfed load addition.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-543.245	KW per customer
Winter	-543.245	KW per customer
Spring	-543.245	KW per customer
Fall	-543.245	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:			Use proposed rates	
Energy Sales Price:		$0.00000	cents/kwh	
Fuel Factor:		$0.00	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$1,415.75	per month per unit

8. CORE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0 0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$5,000	$5,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$0	$0	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$44,195.00	per unit
Labor Costs =	$1,750.00	per unit
b. Annual Equipment Maint. (O & M) =	$2,820.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	1
1992	2	2002	0
1993	2	2003	1
1994	1	2004	0
1995	1	2005	1
1996	0	2006	0
1997	1	2007	1
1998	0	2008	0
1999	1	2009	1
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	2	2	0	2	2
1993	0	2	2	0	4	4
1994	0	1	1	0	5	5
1995	0	1	1	0	6	6
1996	0	0	0	0	6	6
1997	0	1	1	0	7	7
1998	0	0	0	0	7	7
1999	0	1	1	0	8	8
2000	0	0	0	0	8	8
2001	0	1	1	0	9	9
2002	0	0	0	0	9	9
2003	0	1	1	0	10	10
2004	0	0	0	0	10	10
2005	0	1	1	0	11	11
2006	0	0	0	0	11	11
2007	0	1	1	0	12	12
2008	0	0	0	0	12	12
2009	0	1	1	0	13	13
2010	0	0	0	0	13	13

Demand Side Program: STANDBY GENERATOR WITH BACKFEED - 1000KW/CUSTOMER EXPORTED

DSM Type: INTERRUPTIBLE

Description: Customers operate on-site generators in parallel to our system and if their load is less than the generator capacity, backfeed the remainder of the capacity onto our system. This option examines only the backfed load addition.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-1086.490	KW per customer
Winter	-1086.490	KW per customer
Spring	-1086.490	KW per customer
Fall	-1086.490	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules:		Use proposed rates	
Energy Sales Price:	$0.00000	cents/kwh	
Fuel Factor:	$0.00	per kwh	Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time):	$0.00	per unit
Monthly Bill Credit:	$2,821.50	per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0 0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$5,000	$5,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$0	$0	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$44,195.00	per unit
Labor Costs =	$1,750.00	per unit
b. Annual Equipment Maint. (O & M) =	$2,820.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	1
1992	2	2002	0
1993	2	2003	1
1994	1	2004	0
1995	1	2005	1
1996	0	2006	0
1997	1	2007	1
1998	0	2008	0
1999	1	2009	1
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	2	2	0	2	2
1993	0	2	2	0	4	4
1994	0	1	1	0	5	5
1995	0	1	1	0	6	6
1996	0	0	0	0	6	6
1997	0	1	1	0	7	7
1998	0	0	0	0	7	7
1999	0	1	1	0	8	8
2000	0	0	0	0	8	8
2001	0	1	1	0	9	9
2002	0	0	0	0	9	9
2003	0	1	1	0	10	10
2004	0	0	0	0	10	10
2005	0	1	1	0	11	11
2006	0	0	0	0	11	11
2007	0	1	1	0	12	12
2008	0	0	0	0	12	12
2009	0	1	1	0	13	13
2010	0	0	0	0	13	13

Demand Side Program: STANDBY GENERATOR WITH BACKFEED
1,500KW/CUSTOMER EXPORTED

DSM Type: INTERRUPTIBLE

Description: Customers operate on-site generators in parallel to our system and if their load is less than the generator capacity, backfeed the remainder of the capacity onto our system. This option examines only the backfed load addition.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-1629.735	KW per customer
Winter	-1629.735	KW per customer
Spring	-1629.735	KW per customer
Fall	-1629.735	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: Use proposed rates
Energy Sales Price: $0.00000 cents/kwh

Fuel Factor: $0.00 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $0.00 per unit

Monthly Bill Credit: $4,227.25 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0 0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$5,000	$5,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$0	$0	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $44,195.00 per unit

Labor Costs = $1,750.00 per unit

b. Annual Equipment Maint. (O & M) = $2,820.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $0.00 per unit

b. Annual Maintenance cost changes = $0.00 per unit per year

c. per unit per year

d. Extra facilities=

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	1
1992	2	2002	0
1993	2	2003	1
1994	1	2004	0
1995	1	2005	1
1996	0	2006	0
1997	1	2007	1
1998	0	2008	0
1999	1	2009	1
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

Year	Incremental Units Free Riders	Non-Free Riders	Total	Total Cumulative Units Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	2	2	0	2	2
1993	0	2	2	0	4	4
1994	0	1	1	0	5	5
1995	0	1	1	0	6	6
1996	0	0	0	0	6	6
1997	0	1	1	0	7	7
1998	0	0	0	0	7	7
1999	0	1	1	0	8	8
2000	0	0	0	0	8	8
2001	0	1	1	0	9	9
2002	0	0	0	0	9	9
2003	0	1	1	0	10	10
2004	0	0	0	0	10	10
2005	0	1	1	0	11	11
2006	0	0	0	0	11	11
2007	0	1	1	0	12	12
2008	0	0	0	0	12	12
2009	0	1	1	0	13	13

Demand Side Program: STANDBY GENERATOR WITH BACKFEED - 2,000KW/CUSTOMER EXPORTED

DSM Type: INTERRUPTIBLE

Description: Customers operate on-site generators in parallel to our system and if their load is less than the gernerator capacity, backfeed the remainder of the capacity onto our system. This option examines only the backfed load addition.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-2172.980	KW per customer
Winter	-2172.980	KW per customer
Spring	-2172.980	KW per customer
Fall	-2172.980	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: Use proposed rates
Energy Sales Price: $0.00000 cents/kwh

Fuel Factor: $0.00 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $0.00 per unit

Monthly Bill Credit: $5,633.00 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$0.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$0 0	$0	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$5,000	$5,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$0	$0	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs =	$44,195.00	per unit
Labor Costs =	$1,750.00	per unit
b. Annual Equipment Maint. (O & M) =	$2,820.00	per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs=	$0.00	per unit
b. Annual Maintenance cost changes =	$0.00	per unit per year
c.		per unit per year
d. Extra facilities=		

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	1
1992	2	2002	0
1993	2	2003	1
1994	1	2004	0
1995	1	2005	1
1996	0	2006	0
1997	1	2007	1
1998	0	2008	0
1999	1	2009	1
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	2	2	0	2	2
1993	0	2	2	0	4	4
1994	0	1	1	0	5	5
1995	0	1	1	0	6	6
1996	0	0	0	0	6	6
1997	0	1	1	0	7	7
1998	0	0	0	0	7	7
1999	0	1	1	0	8	8
2000	0	0	0	0	8	8
2001	0	1	1	0	9	9
2002	0	0	0	0	9	9
2003	0	1	1	0	10	10
2004	0	0	0	0	10	10
2005	0	1	1	0	11	11
2006	0	0	0	0	11	11
2007	0	1	1	0	12	12
2008	0	0	0	0	12	12
2009	0	1	1	0	13	13
2010	0	0	0	0	13	13

Demand Side Program: STANDBY GENERATOR-CAPACITY IMPROVEMENT - $5000 PAYMENT/CUSTOMER

DSM Type: INTERRUPTIBLE

Description: This option encourages existing Standby Generator customers to add additional load to their generators. Availablity of the program is limited to customers qualifying for Category B.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction (Includes Line Loss)

Summer	-108.649	KW per customer
Winter	-108.649	KW per customer
Spring	-108.649	KW per customer
Fall	-108.649	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: Use proposed rates
Energy Sales Price: $0.00000 cents/kwh

Fuel Factor: $0.00 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $5,000.00 per unit

Monthly Bill Credit: $288.34 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$5,200.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$1,271 0	$1,157	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$1,000	$1,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$35	$35	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%

(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $20,000.00 per unit

b. Annual Maintenance cost changes = $0.00 per unit per year

c. per unit per year

d. Extra facilities=

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	10	2002	0
1993	10	2003	0
1994	10	2004	0
1995	10	2005	0
1996	10	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	10	10	0	10	10
1993	0	10	10	0	20	20
1994	0	10	10	0	30	30
1995	0	10	10	0	40	40
1996	0	10	10	0	50	50
1997	0	0	0	0	50	50
1998	0	0	0	0	50	50
1999	0	0	0	0	50	50
2000	0	0	0	0	50	50
2001	0	0	0	0	50	50
2002	0	0	0	0	50	50
2003	0	0	0	0	50	50
2004	0	0	0	0	50	50
2005	0	0	0	0	50	50
2006	0	0	0	0	50	50
2007	0	0	0	0	50	50
2008	0	0	0	0	50	50
2009	0	0	0	0	50	50
2010	0	0	0	0	50	50

Demand Side Program: STANDBY GENERATOR CAPACITY IMPROVEMENT - $7500 PAYMENT/CUSTOMER

DSM Type: INTERRUPTIBLE

Description: This option encourages existing Standby Generator customers to add additional load to their generators. Availablity of the program is limited to customers qualifying for Category B.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

	System Peak Reduction (Includes Line Loss)	
Summer	-108.649	KW per customer
Winter	-108.649	KW per customer
Spring	-108.649	KW per customer
Fall	-108.649	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: Use proposed rates
Energy Sales Price: $0.00000 cents/kwh

Fuel Factor: $0.00 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $7,500.00 per unit

Monthly Bill Credit: $288.34 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$5,200.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$1,271 0	$1,157	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$1,000	$1,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$35	$35	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+)
Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $20,000.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	10	2002	0
1993	10	2003	0
1994	10	2004	0
1995	10	2005	0
1996	10	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	10	10	0	10	10
1993	0	10	10	0	20	20
1994	0	10	10	0	30	30
1995	0	10	10	0	40	40
1996	0	10	10	0	50	50
1997	0	0	0	0	50	50
1998	0	0	0	0	50	50
1999	0	0	0	0	50	50
2000	0	0	0	0	50	50
2001	0	0	0	0	50	50
2002	0	0	0	0	50	50
2003	0	0	0	0	50	50
2004	0	0	0	0	50	50
2005	0	0	0	0	50	50
2006	0	0	0	0	50	50
2007	0	0	0	0	50	50
2008	0	0	0	0	50	50
2009	0	0	0	0	50	50
2010	0	0	0	0	50	50

Demand Side Program: STANDBY GENERATOR CAPACITY IMPROVEMENT
$10000 PAYMENT/CUSTOMER

DSM Type: INTERRUPTIBLE

Description: This option encourages existing Standby Generator customers to add additional load to their generators. Availablity of the program is limited to customers qualifying for Category B.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

		System Peak Reduction (Includes Line Loss)
Summer	-108.649	KW per customer
Winter	-108.649	KW per customer
Spring	-108.649	KW per customer
Fall	-108.649	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: Use proposed rates
Energy Sales Price: $0.00000 cents/kwh

Fuel Factor: $0.00 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $10,000.00 per unit

Monthly Bill Credit: $288.34 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$5,200.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$1,271 0	$1,157	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$1,000	$1,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$35	$35	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $0.00 per unit

Labor Costs = $0.00 per unit

b. Annual Equipment Maint. (O & M) = $0.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%
(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $20,000.00 per unit

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	0
1992	10	2002	0
1993	10	2003	0
1994	10	2004	0
1995	10	2005	0
1996	10	2006	0
1997	0	2007	0
1998	0	2008	0
1999	0	2009	0
2000	0	2010	0

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	10	10	0	10	10
1993	0	10	10	0	20	20
1994	0	10	10	0	30	30
1995	0	10	10	0	40	40
1996	0	10	10	0	50	50
1997	0	0	0	0	50	50
1998	0	0	0	0	50	50
1999	0	0	0	0	50	50
2000	0	0	0	0	50	50
2001	0	0	0	0	50	50
2002	0	0	0	0	50	50
2003	0	0	0	0	50	50
2004	0	0	0	0	50	50
2005	0	0	0	0	50	50
2006	0	0	0	0	50	50
2007	0	0	0	0	50	50
2008	0	0	0	0	50	50
2009	0	0	0	0	50	50
2010	0	0	0	0	50	50

Demand Side Program: STANDBY GENERATOR-CATEGORY C

DSM Type: INTERRUPTIBLE

Description: Customers operate on-site generators in parallel to our system without exporting (backfeeding) onto our system. This option examines only customers not currently participating in the Standby Generator program.

Assumptions:

1. Unit Definition: Generator

2. Units per Average Customer: 1 generator per customer

3. PEAK REDUCTION: Reductions (-) Increases (+)
Peak Reduction Per Unit

LINE LOSS	MULTIPLIER	VALUE
Trans loss:	100%	3.65%
Dist. loss:	100%	5.00%
Tot Line Loss:		8.65%

System Peak Reduction (Includes Line Loss)

Summer	-814.868	KW per customer
Winter	-814.868	KW per customer
Spring	-814.868	KW per customer
Fall	-814.868	KW per customer

4. CUSTOMER ENERGY/DEMAND CHANGE: Reductions (-) Increases (+)
(no line losses included)

	Energy (KWH)	
Summer	0.0	KWH per customer
Winter	0.0	KWH per customer
Spring	0.0	KWH per customer
Fall	0.0	KWH per customer
Total annual	0	KWH per customer

5. INFLATION: 3.70% per year thru 2010 (GNP deflator for DPSA) Forecast 4/19/91

6. RATES

Rate Schedules: Use proposed rates
Energy Sales Price: $0.00000 cents/kwh

Fuel Factor: $0.00 per kwh Rate 4/19/91 NC prop/SC exist

ESCALATION FACTORS

Rate escal.	4.00%	per year thru 2010	
fuel escal.	4.00%	per year thru 1999	These escalators are not yet updated
Cust Credits	1.85%	per year thru 2010	

7. PAYMENTS:

Upfront payment (one time): $0.00 per unit

Monthly Bill Credit: $2,118.63 per month per unit

8. DUKE COST (Note: All costs to company in this section are shown as (+)

Marketing and Customer Planning Costs (Expenses)	First Year	Annual	
Marketing Training = (consultants, materials, travel & training)	$5,200.00	$0	per year
Marketing Advertising = (brochures, promotional, air time)	$10,444 0	$9,413	per year
Marketing Development (demonstration, travel, misc.)	$0	$0	per year
Marketing GO Labor =	$4,000	$4,000	per year
Field sales labor	$128	$128	per unit
Administration cost =	$90	$90	per unit

Distribution Costs

a. Installation (Capital Costs)

Material Costs = $38,916.00 per unit

Labor Costs = $1,750.00 per unit

b. Annual Equipment Maint. (O & M) = $2,820.00 per unit per year

9. PROGRAM EVALUATION MULTIPLIER 3%

(Multiplier applied to direct costs: Capital, O&M and Credits, no revenue or rate considerations)

10. CUSTOMER COSTS (Note: All costs to customer in this section are shown as (+) Customer Benefits are (-))

Customer Costs Changes

a. Installation and equipment costs= $0.00 per unit

b. Annual Maintenance cost changes = $0.00 per unit per year

c. per unit per year

d. Extra facilities=

11. INCREMENTAL CUSTOMER ADDITIONS

Year	Units	Year	Units
1991	0	2001	1
1992	4	2002	1
1993	4	2003	1
1994	4	2004	1
1995	4	2005	1
1996	4	2006	1
1997	2	2007	1
1998	2	2008	1
1999	2	2009	1
2000	2	2010	1

12. Free Riders: 0.00% customers annually.

13. Overhead Multiplier for Fringe Benefits & Taxes: 26.56%

TOTAL CUSTOMERS OR UNITS

	Incremental Units			Total Cumulative Units		
Year	Free Riders	Non-Free Riders	Total	Free Riders	Non-Free Riders	Total
Accom. 1991	0	0	0	0	0	0
1992	0	4	4	0	4	4
1993	0	4	4	0	8	8
1994	0	4	4	0	12	12
1995	0	4	4	0	16	16
1996	0	4	4	0	20	20
1997	0	2	2	0	22	22
1998	0	2	2	0	24	24
1999	0	2	2	0	26	26
2000	0	2	2	0	28	28
2001	0	1	1	0	29	29
2002	0	1	1	0	30	30
2003	0	1	1	0	31	31
2004	0	1	1	0	32	32
2005	0	1	1	0	33	33
2006	0	1	1	0	34	34
2007	0	1	1	0	35	35
2008	0	1	1	0	36	36
2009	0	1	1	0	37	37
2010	0	1	1	0	38	38

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Appendix VI-5: Projected Accomplishments

The following tables list the 15 years of projected accomplishments in kilowatts (KW), megawatt-hours (MWH), and Duke's direct expenditures for each option that was forwarded to resource integration for the 1991 IP process.

For each existing program their estimated accomplishments through 1991 are also listed.

The KW values are cumulative. The MWH and direct expenditures are annual values.

Numbers in parenthesis are reductions.

CAPACITY (KW) - CUMULATIVE

	1991	1992	1993	1994	1995	1996	1997	1998
EXISTING PROGRAMS								
RES LC - W/H	(30,750)	(35,272)	(37,533)	(38,212)	(38,890)	(39,568)	(40,247)	(40,925)
RES LC - A/C	(365,655)	(419,428)	(446,315)	(454,381)	(462,447)	(470,512)	(478,578)	(486,644)
RES OFF PEAK W/H	(10,549)	(12,100)	(12,876)	(13,109)	(13,341)	(13,574)	(13,807)	(14,039)
HE HEAT PUMP-RES	(1,120)	(2,353)	(3,708)	(3,708)	(3,708)	(3,708)	(3,708)	(3,708)
HE CENTRAL A/C-RES	(397)	(834)	(1,315)	(1,315)	(1,315)	(1,315)	(1,315)	(1,315)
RES DUAL FUEL HP	(851)	(6,170)	(14,150)	(24,256)	(36,491)	(36,491)	(36,491)	(36,491)
HE FREEZER-RES	(41)	(130)	(239)	(239)	(239)	(239)	(239)	(239)
HE REFRIG-RES	(77)	(257)	(449)	(449)	(449)	(449)	(449)	(449)
RES INSULATION NEW RESID.	(7,552)	(6,253)	(12,869)	(20,210)	(29,272)	(38,335)	(47,398)	(56,460)
RES INSULATION LOAN	0	(226)	(452)	(678)	(905)	(1,131)	(1,131)	(1,131)
IS	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)
SG W/O BACKFEED	(28,031)	(36,831)	(45,631)	(54,431)	(63,231)	(69,131)	(75,031)	(80,931)
REVISED EXISTING PROGRAMS AND NEW OPTIONS								
RES LC - W/H	0	(2,640)	(5,316)	(7,985)	(10,663)	(13,314)	(15,965)	(18,613)
RES LC - A/C	0	(75,508)	(152,101)	(228,477)	(305,137)	(380,992)	(456,827)	(532,576)
RES W/H BLANKET	0	(782)	(1,760)	(2,738)	(3,716)	(4,694)	(4,694)	(4,694)
RES HVAC TUNE-UP	0	0	(1,630)	(5,541)	(12,060)	(25,098)	(51,174)	(51,174)
HE CHILLERS FOR A/C	0	(2,538)	(5,075)	(8,882)	(13,323)	(18,398)	(24,743)	(31,087)
HE UNITARY EQUIP. FOR A/C	0	(1,312)	(2,953)	(4,921)	(7,217)	(9,603)	(11,989)	(14,375)
NON-RES HE LTG-EL HTG-EXISTING	0	0	(13,429)	(26,858)	(40,288)	(53,717)	(67,146)	(80,575)
NON-RES HE LTG-EL HTG-NEW	0	0	(6,162)	(12,323)	(18,485)	(24,646)	(30,808)	(36,970)
NON-RES HE LTG-FOSSIL HTG-EXISTING	0	0	(12,834)	(25,669)	(38,503)	(51,337)	(64,171)	(77,006)
NON-RES HE LTG-FOSSIL HTG-NEW	0	0	(12,363)	(24,726)	(37,089)	(49,453)	(61,816)	(74,179)
NON-RES HE LTG-OPT-EXISTING	0	0	(6,712)	(13,423)	(20,135)	(26,847)	(33,558)	(40,270)
NON-RES HE LTG-OPT-NEW	0	0	(1,496)	(2,992)	(4,488)	(5,984)	(7,480)	(8,977)
NON-RES HIGH-EL HTG	0	0	0	0	(45,739)	(91,478)	(137,217)	(182,956)

CAPACITY (KW) - CUMULATIVE

	1991	1992	1993	1994	1995	1996	1997	1998
NON-RES HIGH-FOSSIL HTG	0	0	0	0	(45,783)	(91,565)	(137,348)	(183,131)
NON-RES HIGH-OPT	0	0	0	0	(16,159)	(32,318)	(48,476)	(64,635)
MOTOR SYSTEMS-$6/HP	0	0	0	(24,359)	(48,718)	(73,077)	(97,436)	(121,795)
MOTOR SYSTEMS-$12/HP	0	0	0	(60,897)	(121,795)	(182,692)	(243,589)	(304,487)
MOTOR SYSTEMS-$25/HP	0	0	0	(97,436)	(194,871)	(292,307)	(389,743)	(487,179)
IS-START IN 1992	0	(94,409)	(188,818)	(283,227)	(377,636)	(472,046)	(472,046)	(472,046)
IS-START IN 1993	0	0	(94,409)	(188,818)	(283,227)	(377,636)	(472,046)	(472,046)
IS-START IN 1994	0	0	0	(94,409)	(188,818)	(283,227)	(377,636)	(472,046)
IS-START IN 1995	0	0	0	0	(94,409)	(188,818)	(283,227)	(377,636)
IS-START IN 1996	0	0	0	0	0	(94,409)	(188,818)	(283,227)
IS-START IN 1998	0	0	0	0	0	0	0	(94,409)
IS-START IN 2000	0	0	0	0	0	0	0	0
IS-START IN 2003	0	0	0	0	0	0	0	0
IS-START IN 2006	0	0	0	0	0	0	0	0
SG W/ BACKFEED 500 KW/CUS	0	(1,086)	(2,173)	(2,716)	(3,259)	(3,259)	(3,803)	(3,803)
SG W/ BACKFEED 1000 KW/CUS	0	(2,173)	(4,346)	(5,432)	(6,519)	(6,519)	(7,605)	(7,605)
SG W/ BACKFEED 1500 KW/CUS	0	(3,259)	(6,519)	(8,149)	(9,778)	(9,778)	(11,408)	(11,408)
SG W/ BACKFEED 2000 KW/CUS	0	(4,346)	(8,692)	(10,865)	(13,038)	(13,038)	(15,211)	(15,211)
SG-CIP $5000/CUS	0	(1,086)	(2,173)	(3,259)	(4,346)	(5,432)	(5,432)	(5,432)
SG-CIP $7500/CUS	0	(1,086)	(2,173)	(3,259)	(4,346)	(5,432)	(5,432)	(5,432)
SG-CIP $10000/CUS	0	(1,086)	(2,173)	(3,259)	(4,346)	(5,432)	(5,432)	(5,432)
SG - CAT C	0	(3,259)	(6,519)	(9,778)	(13,038)	(16,297)	(17,927)	(19,557)
RES OFF PEAK W/H-SUBMETERED	0	(1,152)	(2,304)	(3,457)	(4,609)	(5,761)	(6,913)	(8,066)
RES OFF PEAK W/H-FLAT PAY	0	(1,251)	(2,502)	(3,753)	(5,004)	(6,255)	(6,255)	(6,255)

CAPACITY (KW) - CUMULATIVE

	1999	2000	2001	2002	2003	2004	2005	2006
EXISTING PROGRAMS								
RES LC - W/H	(41,603)	(41,603)	(41,603)	(41,603)	(41,603)	(41,603)	(41,603)	(41,603)
RES LC - A/C	(494,710)	(494,710)	(494,710)	(494,710)	(494,710)	(494,710)	(494,710)	(494,710)
RES OFF PEAK W/H	(14,272)	(14,272)	(14,272)	(14,272)	(14,272)	(14,272)	(14,272)	(14,272)
HE HEAT PUMP-RES	(3,708)	(3,708)	(3,708)	(3,708)	(3,708)	(3,708)	(3,708)	(3,708)
HE CENTRAL A/C-RES	(1,315)	(1,315)	(1,315)	(1,315)	(1,315)	(1,315)	(1,315)	(1,315)
RES DUAL FUEL HP	(36,491)	(36,491)	(36,491)	(36,491)	(36,491)	(36,491)	(36,491)	(36,491)
HE FREEZER-RES	(239)	(239)	(239)	(239)	(239)	(239)	(239)	(239)
HE REFRIG-RES	(449)	(449)	(449)	(449)	(449)	(449)	(449)	(449)
RES INSULATION NEW RESID.	(65,523)	(74,585)	(74,585)	(74,585)	(74,585)	(74,585)	(74,585)	(74,585)
RES INSULATION LOAN	(1,131)	(1,131)	(1,131)	(1,131)	(1,131)	(1,131)	(1,131)	(1,131)
IS	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)	(566,455)
SG W/O BACKFEED	(86,831)	(92,731)	(95,631)	(98,531)	(101,431)	(104,331)	(107,231)	(110,131)
REVISED EXISTING PROGRAMS AND NEW OPTIONS								
RES LC - W/H	(21,262)	(23,907)	(24,855)	(25,802)	(26,752)	(27,697)	(28,631)	(28,631)
RES LC - A/C	(608,350)	(684,021)	(713,007)	(741,957)	(771,004)	(799,897)	(829,274)	(859,143)
RES W/H BLANKET	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)
RES HVAC TUNE-UP	(51,174)	(51,174)	(51,174)	(51,174)	(51,174)	(51,174)	(51,174)	(51,174)
HE CHILLERS FOR A/C	(37,431)	(43,775)	(49,485)	(55,195)	(60,270)	(64,711)	(67,883)	(70,421)
HE UNITARY EQUIP. FOR A/C	(16,761)	(19,147)	(21,533)	(23,919)	(26,305)	(28,691)	(31,077)	(33,463)
NON-RES HE LTG-EL HTG-EXISTING	(94,005)	(107,434)	(120,863)	(134,292)	(147,722)	(161,151)	(174,580)	(188,009)
NON-RES HE LTG-EL HTG-NEW	(43,131)	(49,293)	(55,455)	(61,616)	(67,778)	(73,939)	(80,101)	(86,263)
NON-RES HE LTG-FOSSIL HTG-EXISTING	(89,840)	(102,674)	(115,508)	(128,343)	(141,177)	(154,011)	(166,845)	(179,680)
NON-RES HE LTG-FOSSIL HTG-NEW	(86,542)	(98,905)	(111,268)	(123,631)	(135,994)	(148,358)	(160,721)	(173,084)
NON-RES HE LTG-OPT-EXISTING	(46,982)	(53,693)	(60,405)	(67,117)	(73,828)	(80,540)	(87,252)	(93,963)
NON-RES HE LTG-OPT-NEW	(10,473)	(11,969)	(13,465)	(14,961)	(16,457)	(17,953)	(19,449)	(20,945)
NON-RES HIGH-EL HTG	(228,695)	(274,434)	(320,172)	(365,911)	(411,650)	(457,389)	(503,128)	(548,867)

CAPACITY (KW) - CUMULATIVE

	1999	2000	2001	2002	2003	2004	2005	2006
NON-RES HIGH-FOSSIL HTG	(228,913)	(274,696)	(320,479)	(366,262)	(412,044)	(457,827)	(503,610)	(549,392)
NON-RES HIGH-OPT	(80,794)	(96,953)	(113,112)	(129,270)	(145,429)	(161,588)	(177,747)	(193,906)
MOTOR SYSTEMS-$6/HP	(146,154)	(170,513)	(194,872)	(219,231)	(243,590)	(267,948)	(267,948)	(267,948)
MOTOR SYSTEMS-$12/HP	(365,384)	(426,281)	(487,179)	(548,076)	(608,973)	(669,871)	(669,871)	(669,871)
MOTOR SYSTEMS-$25/HP	(584,614)	(682,050)	(779,486)	(876,922)	(974,357)	(1,071,793)	(1,071,793)	(1,071,793)
IS-START IN 1992	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)
IS-START IN 1993	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)
IS-START IN 1994	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)
IS-START IN 1995	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)
IS-START IN 1996	(377,636)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)
IS-START IN 1998	(188,818)	(283,227)	(377,636)	(472,046)	(472,046)	(472,046)	(472,046)	(472,046)
IS-START IN 2000	0	(94,409)	(188,818)	(283,227)	(377,636)	(472,046)	(472,046)	(472,046)
IS-START IN 2003	0	0	0	0	(94,409)	(188,818)	(283,227)	(377,636)
IS-START IN 2006	0	0	0	0	0	0	0	(94,409)
SG W/ BACKFEED 500 KW/CUS	(4,346)	(4,346)	(4,889)	(4,889)	(5,432)	(5,432)	(5,976)	(5,976)
SG W/ BACKFEED 1000 KW/CUS	(8,692)	(8,692)	(9,778)	(9,778)	(10,865)	(10,865)	(11,951)	(11,951)
SG W/ BACKFEED 1500 KW/CUS	(13,038)	(13,038)	(14,668)	(14,668)	(16,297)	(16,297)	(17,927)	(17,927)
SG W/ BACKFEED 2000 KW/CUS	(17,384)	(17,384)	(19,557)	(19,557)	(21,730)	(21,730)	(23,903)	(23,903)
SG-CIP $5000/CUS	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)
SG-CIP $7500/CUS	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)
SG-CIP $10000/CUS	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)	(5,432)
SG - CAT C	(21,187)	(22,816)	(23,631)	(24,446)	(25,261)	(26,076)	(26,891)	(27,705)
RES OFF PEAK W/H-SUBMETERED	(9,218)	(10,370)	(10,370)	(10,370)	(10,370)	(10,370)	(10,370)	(10,370)
RES OFF PEAK W/H-FLAT PAY	(6,255)	(6,255)	(6,255)	(6,255)	(6,255)	(6,255)	(6,255)	(6,255)
TOTAL	(2,578,742)	(2,853,667)	(3,066,361)	(3,279,018)	(3,491,141)	(3,702,469)	(3,794,234)	(3,884,923)

ENERGY (MWH) - ANNUAL

	1991	1992	1993	1994	1995	1996	1997	1998
EXISTING PROGRAMS								
RES LC - W/H	0	0	0	0	0	0	0	0
RES LC - A/C	0	0	0	0	0	0	0	0
RES OFF PEAK W/H	0	0	0	0	0	0	0	0
HE HEAT PUMP-RES	(2,585)	(5,429)	(8,558)	(8,558)	(8,558)	(8,558)	(8,558)	(8,558)
HE CENTRAL A/C-RES	(484)	(1,016)	(1,601)	(1,601)	(1,601)	(1,601)	(1,601)	(1,601)
RES DUAL FUEL HP	1,122	7,785	17,779	30,438	45,762	45,762	45,762	45,762
HE FREEZER-RES	(540)	(1,125)	(1,844)	(1,844)	(1,844)	(1,844)	(1,844)	(1,844)
HE REFRIG-RES	(856)	(1,848)	(2,909)	(2,909)	(2,909)	(2,909)	(2,909)	(2,909)
RES INSULATION NEW RESID.	32,834	27,187	55,949	87,864	127,265	166,666	206,066	245,467
RES INSULATION LOAN	0	(5,488)	(10,975)	(16,463)	(21,950)	(27,438)	(27,438)	(27,438)
IS	0	0	0	0	0	0	0	0
SG W/O BACKFEED	0	0	0	0	0	0	0	0
REVISED EXISTING PROGRAMS AND NEW OPTIONS								
RES LC - W/H	0	0	0	0	0	0	0	0
RES LC - A/C	0	0	0	0	0	0	0	0
RES W/H BLANKET	0	(8,844)	(19,899)	(30,954)	(42,010)	(53,065)	(53,065)	(53,065)
RES HVAC TUNE-UP	0	0	(3,374)	(11,470)	(24,965)	(51,953)	(105,930)	(105,930)
HE CHILLERS FOR A/C	0	(6,187)	(12,374)	(21,655)	(32,483)	(44,857)	(60,325)	(75,793)
HE UNITARY EQUIP. FOR A/C	0	(959)	(2,159)	(3,598)	(5,276)	(7,021)	(8,765)	(10,509)
NON-RES HE LTG-EL HTG-EXISTING	0	0	(39,129)	(78,258)	(117,387)	(156,516)	(195,645)	(234,774)
NON-RES HE LTG-EL HTG-NEW	0	0	(17,953)	(35,906)	(53,860)	(71,813)	(89,766)	(107,719)
NON-RES HE LTG-FOSSIL HTG-EXISTING	0	0	(54,679)	(109,359)	(164,038)	(218,717)	(273,397)	(328,076)
NON-RES HE LTG-FOSSIL HTG-NEW	0	0	(52,672)	(105,344)	(158,016)	(210,688)	(263,360)	(316,033)
NON-RES HE LTG-OPT-EXISTING	0	0	(43,088)	(86,176)	(129,264)	(172,352)	(215,440)	(258,528)
NON-RES HE LTG-OPT-NEW	0	0	(9,605)	(19,210)	(28,814)	(38,419)	(48,024)	(57,629)
NON-RES HIGH-EL HTG	0	0	0	0	(130,351)	(260,701)	(391,052)	(521,402)

ENERGY (MWH) - ANNUAL

	1991	1992	1993	1994	1995	1996	1997	1998
NON-RES HIGH-FOSSIL HTG	0	0	0	0	(196,806)	(393,611)	(590,417)	(787,223)
NON-RES HIGH-OPT	0	0	0	0	(100,532)	(201,065)	(301,597)	(402,130)
MOTOR SYSTEMS-$6/HP	0	0	0	(142,095)	(284,190)	(426,286)	(568,381)	(710,476)
MOTOR SYSTEMS-$12/HP	0	0	0	(355,238)	(710,476)	(1,065,714)	(1,420,951)	(1,776,189)
MOTOR SYSTEMS-$25/HP	0	0	0	(568,380)	(1,136,761)	(1,705,141)	(2,273,522)	(2,841,902)
IS-START IN 1992	0	0	0	0	0	0	0	0
IS-START IN 1993	0	0	0	0	0	0	0	0
IS-START IN 1994	0	0	0	0	0	0	0	0
IS-START IN 1995	0	0	0	0	0	0	0	0
IS-START IN 1996	0	0	0	0	0	0	0	0
IS-START IN 1998	0	0	0	0	0	0	0	0
IS-START IN 2000	0	0	0	0	0	0	0	0
IS-START IN 2003	0	0	0	0	0	0	0	0
IS-START IN 2006	0	0	0	0	0	0	0	0
SG W/ BACKFEED 500 KW/CUS	0	0	0	0	0	0	0	0
SG W/ BACKFEED 1000 KW/CUS	0	0	0	0	0	0	0	0
SG W/ BACKFEED 1500 KW/CUS	0	0	0	0	0	0	0	0
SG W/ BACKFEED 2000 KW/CUS	0	0	0	0	0	0	0	0
SG-CIP $5000/CUS	0	0	0	0	0	0	0	0
SG-CIP $7500/CUS	0	0	0	0	0	0	0	0
SG-CIP $10000/CUS	0	0	0	0	0	0	0	0
SG - CAT C	0	0	0	0	0	0	0	0
RES OFF PEAK W/H-SUBMETERED	0	1,763	3,525	5,288	7,050	8,813	10,575	12,338
RES OFF PEAK W/H-FLAT PAY	0	1,763	3,525	5,288	7,050	8,813	8,813	8,813

ENERGY (MWH) - ANNUAL

	1999	2000	2001	2002	2003	2004	2005	2006
EXISTING PROGRAMS								
RES LC - W/H	0	0	0	0	0	0	0	0
RES LC - A/C	0	0	0	0	0	0	0	0
RES OFF PEAK W/H	0	0	0	0	0	0	0	0
HE HEAT PUMP-RES	(8,558)	(8,558)	(8,558)	(8,558)	(8,558)	(8,558)	(8,558)	(8,558)
HE CENTRAL A/C-RES	(1,601)	(1,601)	(1,601)	(1,601)	(1,601)	(1,601)	(1,601)	(1,601)
RES DUAL FUEL HP	45,762	45,762	45,762	45,762	45,762	45,762	45,762	45,762
HE FREEZER-RES	(1,844)	(1,844)	(1,844)	(1,844)	(1,844)	(1,844)	(1,844)	(1,844)
HE REFRIG-RES	(2,909)	(2,909)	(2,909)	(2,909)	(2,909)	(2,909)	(2,909)	(2,909)
RES INSULATION NEW RESID.	284,868	324,269	324,269	324,269	324,269	324,269	324,269	324,269
RES INSULATION LOAN	(27,438)	(27,438)	(27,438)	(27,438)	(27,438)	(27,438)	(27,438)	(27,438)
IS	0	0	0	0	0	0	0	0
SG W/O BACKFEED	0	0	0	0	0	0	0	0
REVISED EXISTING PROGRAMS AND NEW OPTIONS								
RES LC - W/H	0	0	0	0	0	0	0	0
RES LC - A/C	0	0	0	0	0	0	0	0
RES W/H BLANKET	(53,065)	(53,065)	(53,065)	(53,065)	(53,065)	(53,065)	(53,065)	(53,065)
RES HVAC TUNE-UP	(105,930)	(105,930)	(105,930)	(105,930)	(105,930)	(105,930)	(105,930)	(105,930)
HE CHILLERS FOR A/C	(91,261)	(106,729)	(120,651)	(134,572)	(146,946)	(157,774)	(165,508)	(171,695)
HE UNITARY EQUIP. FOR A/C	(12,253)	(13,998)	(15,742)	(17,486)	(19,231)	(20,975)	(22,719)	(24,463)
NON-RES HE LTG-EL HTG-EXISTING	(273,903)	(313,032)	(352,161)	(391,289)	(430,418)	(469,547)	(508,676)	(547,805)
NON-RES HE LTG-EL HTG-NEW	(125,672)	(143,625)	(161,579)	(179,532)	(197,485)	(215,438)	(233,391)	(251,345)
NON-RES HE LTG-FOSSIL HTG-EXISTING	(382,755)	(437,435)	(492,114)	(546,793)	(601,473)	(656,152)	(710,831)	(765,511)
NON-RES HE LTG-FOSSIL HTG-NEW	(368,705)	(421,377)	(474,049)	(526,721)	(579,393)	(632,065)	(684,737)	(737,409)
NON-RES HE LTG-OPT-EXISTING	(301,616)	(344,704)	(387,792)	(430,880)	(473,968)	(517,056)	(560,144)	(603,233)
NON-RES HE LTG-OPT-NEW	(67,233)	(76,838)	(86,443)	(96,048)	(105,652)	(115,257)	(124,862)	(134,467)
NON-RES HIGH-EL HTG	(651,753)	(782,103)	(912,454)	(1,042,805)	(1,173,155)	(1,303,506)	(1,433,856)	(1,564,207)

ENERGY (MWH) - ANNUAL

	1999	2000	2001	2002	2003	2004	2005	2006
NON-RES HIGH-FOSSIL HTG	(984,028)	(1,180,834)	(1,377,640)	(1,574,445)	(1,771,251)	(1,968,057)	(2,164,862)	(2,361,668)
NON-RES HIGH-OPT	(502,662)	(603,194)	(703,727)	(804,259)	(904,792)	(1,005,324)	(1,105,856)	(1,206,389)
MOTOR SYSTEMS-$6/HP	(852,571)	(994,667)	(1,136,762)	(1,278,857)	(1,420,952)	(1,563,047)	(1,563,047)	(1,563,047)
MOTOR SYSTEMS-$12/HP	(2,131,427)	(2,486,665)	(2,841,903)	(3,197,141)	(3,552,379)	(3,907,616)	(3,907,616)	(3,907,616)
MOTOR SYSTEMS-$25/HP	(3,410,283)	(3,978,663)	(4,547,044)	(5,115,424)	(5,683,805)	(6,252,185)	(6,252,185)	(6,252,185)
IS-START IN 1992	0	0	0	0	0	0	0	0
IS-START IN 1993	0	0	0	0	0	0	0	0
IS-START IN 1994	0	0	0	0	0	0	0	0
IS-START IN 1995	0	0	0	0	0	0	0	0
IS-START IN 1996	0	0	0	0	0	0	0	0
IS-START IN 1998	0	0	0	0	0	0	0	0
IS-START IN 2000	0	0	0	0	0	0	0	0
IS-START IN 2003	0	0	0	0	0	0	0	0
IS-START IN 2006	0	0	0	0	0	0	0	0
SG W/ BACKFEED 500 KW/CUS	0	0	0	0	0	0	0	0
SG W/ BACKFEED 1000 KW/CUS	0	0	0	0	0	0	0	0
SG W/ BACKFEED 1500 KW/CUS	0	0	0	0	0	0	0	0
SG W/ BACKFEED 2000 KW/CUS	0	0	0	0	0	0	0	0
SG-CIP $5000/CUS	0	0	0	0	0	0	0	0
SG-CIP $7500/CUS	0	0	0	0	0	0	0	0
SG-CIP $10000/CUS	0	0	0	0	0	0	0	0
SG - CAT C	0	0	0	0	0	0	0	0
RES OFF PEAK W/H-SUBMETERED	14,101	15,863	15,863	15,863	15,863	15,863	15,863	15,863
RES OFF PEAK W/H-FLAT PAY	8,813	8,813	8,813	8,813	8,813	8,813	8,813	8,813

DIRECT EXPENDITURES - ANNUAL
($)

	1992	1993	1994	1995	1996	1997	1998	1999
EXISTING PROGRAMS								
RES LC - W/H	3,048,509	3,104,906	3,162,347	3,220,851	3,280,436	3,341,124	3,402,935	3,465,890
RES LC - A/C	10,780,860	10,980,306	11,183,442	11,390,335	11,601,056	11,815,676	12,034,266	12,256,900
RES OFF PEAK W/H	0	0	0	0	0	0	0	0
HE HEAT PUMP - RES	1,450,230	1,656,178	13,402	0	0	0	0	0
HE CENTRAL A/C - RES	469,709	535,594	0	0	0	0	0	0
RES DUAL FUEL HP	2,731,188	4,169,631	5,439,344	6,801,752	0	0	0	0
HE FREEZER - RES	176,286	213,781	52,441	0	0	0	0	0
HE REFRIG - RES	466,137	516,171	23,307	0	0	0	0	0
RES INSULATION NEW RESID.	4,745,807	5,109,697	5,496,236	5,906,104	5,856,902	6,066,697	6,284,674	6,528,574
RES INSULATION LOAN	554,261	775,257	1,012,647	1,267,375	1,046,822	1,067,318	1,087,821	1,108,299
IS	25,326,000	25,452,630	25,579,893	25,707,793	25,836,332	25,965,513	26,095,341	26,225,818
SG W/O BACKFEED	1,582,012	1,934,051	2,348,107	2,794,884	3,162,207	3,672,314	4,221,186	4,812,365
REVISED EXISTING PROGAMS AND NEW OPTIONS								
RES LC - W/H	1,739,329	1,946,869	2,302,977	2,684,929	3,061,261	3,469,067	3,893,576	4,339,384
RES LC - A/C	6,938,993	8,735,461	11,041,755	13,482,838	15,926,941	18,523,199	21,216,700	24,026,713
RES W/H BLANKET	882,235	892,542	925,566	959,812	995,325	0	0	0
RES HVAC TUNE-UP	0	1,334,104	2,756,379	4,645,645	9,361,791	18,999,723	0	0
HE CHILLERS FOR A/C	1,075,108	1,094,212	1,662,575	1,972,812	2,294,037	2,915,960	2,970,674	3,026,430
HE UNITARY EQUIP. FOR A/C	434,055	536,589	650,848	770,185	817,718	837,532	857,886	878,795
NON-RES HE LTG-EL HTG-EXISTING	0	3,126,387	3,170,579	3,234,146	3,299,070	3,365,384	3,433,120	3,502,312
NON-RES HE LTG-EL HTG-NEW	0	1,510,959	1,532,244	1,562,908	1,594,225	1,626,210	1,658,879	1,692,248
NON-RES HE LTG-FOSSIL HTG-EXISTING	0	3,126,175	3,164,071	3,229,782	3,296,974	3,365,684	3,435,951	3,507,814
NON-RES HE LTG-FOSSIL HTG-NEW	0	3,168,946	3,207,117	3,273,557	3,341,490	3,410,952	3,481,982	3,554,619
NON-RES HE LTG-OPT-EXISTING	0	1,497,579	1,519,904	1,549,959	1,580,641	1,611,965	1,643,945	1,676,597
NON-RES HE LTG-OPT-NEW	0	351,761	356,992	364,040	371,235	378,580	386,079	393,735

DIRECT EXPENDITURES - ANNUAL
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	1992	1993	1994	1995	1996	1997	1998	1999
NON-RES HIGH-EL HTG	0	0	0	24,563,006	24,929,905	25,420,869	25,922,016	26,433,577
NON-RES HIGH-FOSSIL HTG	0	0	0	24,566,111	24,932,801	25,423,871	25,925,130	26,436,806
NON-RES HIGH-OPT	0	0	0	8,669,678	8,803,151	8,976,592	9,153,633	9,334,355
MOTOR SYSTEMS - $6/HP	0	0	23,170,234	23,721,255	24,598,942	25,509,102	26,452,939	27,431,698
MOTOR SYSTEMS - $12/HP	0	0	75,799,871	78,298,189	81,195,222	84,199,445	87,314,825	90,545,473
MOTOR SYSTEMS - $25/HP	0	0	217,849,444	225,603,595	233,950,928	242,607,113	251,583,576	260,892,168
IS-START IN 1992	4,638,941	9,063,969	13,541,337	18,070,648	22,652,718	22,580,888	22,714,674	22,849,902
IS-START IN 1993	0	4,684,797	9,109,949	13,613,653	18,169,836	22,779,332	22,714,674	22,849,902
IS-START IN 1994	0	0	4,717,388	9,168,092	13,698,888	18,282,726	22,920,461	22,849,902
IS-START IN 1995	0	0	0	4,750,506	9,227,010	13,785,196	18,397,001	23,063,303
IS-START IN 1996	0	0	0	0	4,784,167	9,286,726	13,872,607	18,512,700
IS-START IN 1998	0	0	0	0	0	0	4,853,187	9,408,641
IS-START IN 2000	0	0	0	0	0	0	0	0
IS-START IN 2003	0	0	0	0	0	0	0	0
IS-START IN 2006	0	0	0	0	0	0	0	0
SG W/ BACKFEED-500 KW/CUS	146,923	194,251	168,863	195,589	143,785	229,180	173,887	265,400
SG W/ BACKFEED-1000 KW/CUS	182,316	266,346	260,649	307,771	258,042	364,945	312,164	426,355
SG W/ BACKFEED-1500 KW/CUS	217,709	338,442	352,436	419,953	372,299	500,711	450,442	587,310
SG W/ BACKFEED-2000 KW/CUS	253,102	410,537	444,223	532,134	486,556	636,477	588,720	748,265
SG-CIP- $5000/CUS	99,218	132,330	172,524	214,161	257,281	198,910	202,590	206,338
SG-CIP- $7500/CUS	125,444	159,042	199,730	241,870	285,503	198,910	202,590	206,338
SG-CIP- $10000/CUS	151,670	185,753	226,935	269,579	313,724	198,910	202,590	206,338
SG-CAT C	315,769	439,728	575,600	716,905	863,821	845,966	932,404	1,022,097
RES OFF PEAK W/H-SUBMETERED	1,000,554	994,645	1,069,236	1,147,986	1,231,099	1,318,790	1,411,286	1,508,821
RES OFF PEAK W/H-FLAT PAY	1,075,737	1,382,540	1,794,335	2,222,539	2,667,693	1,980,516	2,021,053	2,062,485

DIRECT EXPENDITURES - ANNUAL
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	2000	2001	2002	2003	2004	2005	2006
EXISTING PROGRAMS							
RES LC - W/H	3,530,008	3,595,314	3,661,827	3,729,571	3,798,568	3,868,841	3,940,415
RES LC - A/C	12,483,653	12,714,600	12,949,820	13,189,392	13,433,396	13,681,913	13,935,029
RES OFF PEAK W/H	0	0	0	0	0	0	0
HE HEAT PUMP - RES	0	0	0	0	0	0	0
HE CENTRAL A/C - RES	0	0	0	0	0	0	0
RES DUAL FUEL HP	0	0	0	0	0	0	0
HE FREEZER - RES	0	0	0	0	0	0	0
HE REFRIG - RES	0	0	0	0	0	0	0
RES INSULATION NEW RESID.	6,782,718	477,537	477,537	477,537	477,537	477,537	477,537
RES INSULATION LOAN	0	0	0	0	0	0	0
IS	26,356,947	26,488,731	26,621,175	26,754,281	26,888,052	27,022,493	27,157,605
SG W/O BACKFEED	5,447,433	5,989,437	6,709,697	7,481,740	8,308,726	9,193,992	10,141,065
REVISED EXISTING PROGAMS AND NEW OPTIONS							
RES LC - W/H	4,801,457	3,913,944	4,143,699	4,386,540	4,632,227	4,881,354	4,251,987
RES LC - A/C	26,935,599	24,679,300	26,164,176	27,717,439	29,299,069	31,014,194	32,810,803
RES W/H BLANKET	0	0	0	0	0	0	0
RES HVAC TUNE-UP	0	0	0	0	0	0	0
HE CHILLERS FOR A/C	3,083,246	2,829,562	2,882,757	2,613,664	2,333,553	1,706,638	1,397,272
HE UNITARY EQUIP. FOR A/C	900,278	922,352	945,035	968,345	992,302	1,016,926	1,042,238
NON-RES HE LTG-EL HTG-EXISTING	3,572,994	3,645,202	3,718,971	3,794,340	3,871,345	3,950,028	4,030,427
NON-RES HE LTG-EL HTG-NEW	1,726,333	1,761,152	1,796,722	1,833,060	1,870,186	1,908,117	1,946,873
NON-RES HE LTG-FOSSIL HTG-EXISTING	3,581,314	3,656,491	3,733,390	3,812,053	3,892,527	3,974,858	4,059,094
NON-RES HE LTG-FOSSIL HTG-NEW	3,628,904	3,704,879	3,782,587	3,862,071	3,943,378	4,026,553	4,111,646
NON-RES HE LTG-OPT-EXISTING	1,709,936	1,743,978	1,778,739	1,814,235	1,850,483	1,887,502	1,925,308
NON-RES HE LTG-OPT-NEW	401,551	409,532	417,681	426,001	434,498	443,175	452,035

DIRECT EXPENDITURES - ANNUAL
($)

	2000	2001	2002	2003	2004	2005	2006
NON-RES HIGH-EL HTG	26,955,785	27,488,883	28,033,116	28,588,738	29,156,008	29,735,192	30,326,565
NON-RES HIGH-FOSSIL HTG	26,959,134	27,492,355	28,036,716	28,592,471	29,159,880	29,739,207	30,330,728
NON-RES HIGH-OPT	9,518,842	9,707,178	9,899,451	10,095,751	10,296,170	10,500,801	10,709,741
MOTOR SYSTEMS - $6/HP	28,446,671	29,499,198	30,590,668	31,722,523	32,896,256	0	0
MOTOR SYSTEMS - $12/HP	93,895,656	97,369,795	100,972,477	104,708,459	108,582,672	0	0
MOTOR SYSTEMS - $25/HP	270,545,178	280,555,350	290,935,898	301,700,526	312,863,446	0	0
IS-START IN 1992	22,986,607	23,124,827	23,264,599	23,405,963	23,548,961	23,693,635	23,840,028
IS-START IN 1993	22,986,607	23,124,827	23,264,599	23,405,963	23,548,961	23,693,635	23,840,028
IS-START IN 1994	22,986,607	23,124,827	23,264,599	23,405,963	23,548,961	23,693,635	23,840,028
IS-START IN 1995	22,986,607	23,124,827	23,264,599	23,405,963	23,548,961	23,693,635	23,840,028
IS-START IN 1996	23,207,904	46,249,653	23,264,599	23,405,963	23,548,961	23,693,635	23,840,028
IS-START IN 1998	14,050,862	18,748,525	23,502,574	23,405,963	23,548,961	23,693,635	23,840,028
IS-START IN 2000	4,924,587	9,534,026	14,233,908	18,990,525	23,804,872	23,693,635	23,840,028
IS-START IN 2003	0	0	0	5,036,487	9,729,062	14,518,065	19,365,876
IS-START IN 2006	0	0	0	0	0	0	5,154,645
SG W/ BACKFEED-500 KW/CUS	206,362	304,435	241,377	346,482	279,108	391,754	319,745
SG W/ BACKFEED-1000 KW/CUS	370,295	492,271	432,688	562,983	499,614	638,797	571,359
SG W/ BACKFEED-1500 KW/CUS	534,228	680,107	623,999	779,483	720,120	885,841	822,973
SG W/ BACKFEED-2000 KW/CUS	698,161	867,944	815,311	995,984	940,626	1,132,885	1,074,587
SG-CIP- $5000/CUS	210,155	214,043	218,003	222,036	226,144	230,327	234,588
SG-CIP- $7500/CUS	210,155	214,043	218,003	222,036	226,144	230,327	234,588
SG-CIP-.$10000/CUS	210,155	214,043	218,003	222,036	226,144	230,327	234,588
SG-CAT C	1,115,152	1,104,682	1,165,048	1,227,495	1,292,091	1,358,902	1,428,001
RES OFF PEAK W/H-SUBMETERED	1,611,641	438,595	454,823	471,651	489,102	507,199	525,965
RES OFF PEAK W/H-FLAT PAY	2,104,833	2,148,119	2,192,367	2,237,600	2,283,844	2,331,122	2,379,460

Appendix VI-6: Environmental Discussion

Since manufacturing drives the economy of Duke's region (each manufacturing job creates another four to seven jobs in associated services, retailing, construction, etc.) significant attention must be given to preserving the industrial base of customers in order to and stabilize the local economy.

Global competition has forced manufacturing customers to reach new levels of productivity and efficiency in order to survive, but environmental issues are beginning to have a significant impact on some customer segments. Surfacing regulations and enforcement will play an important role in the long term viability and survivability of many customers, as their capital and operating resources will be required in order to reduce or eliminate air emissions, water and wastewater discharges, and solid and hazardous waste generation and disposal. .Environmental regulations are having similar effects on certain commercial groups, such as hospitals and municipal water systems.

The more progressive manufacturing customers have embraced a "zero discharge" philosophy. Some of the benefits which they see in "zero discharge" are:

1. Minimization of environmental reporting
2. Elimination of costs and delays.for discharge permits
3. Avoidance of disposal cost premiums
4. Elimination of "cradle-to-grave" liability for hazardous waste
5. Positive public image

Many times as customers move toward "zero discharge" status, productivity and energy efficiency increase. Efficient electric technologies clearly have major environmental and productivity implications for customers.

Environmental Option Analysis

Environmental options are somewhat more complex to evaluate than other types of options because they typically transfer some environmental emissions burden to the electric utility. The benefit to the customer from reduction in water, air or solid waste must be computed in monetary value. Any additional costs to the utility from increased stack emissions must also be assigned a dollar value. Similarly, any societal benefits and costs should be quantified. All these benefits and costs could then be incorporated into appropriate LCP tests. Work is underway at EPRI to find ways to quantify these benefits and costs but no standard techniques have yet been derived. Until standard techniques are recognized research must be performed on a case-by-case basis. Two examples of environmental options are discussed in the following sections.

1. **Metal Finishing - Recover Plating Solutions**

   Metal plating and circuit board manufacturers have stringent federal pre-treatment standards for their discharge water. The carry-over of plating solutions into rinse tanks contributes to discharge of heavy metals and metal salts in the discharge water stream. The predominant method of removing the metals is to form a precipitate, remove the water, and ship the resultant sludge to a hazardous waste dump.

An alternative to the sludge disposal method is to alter the process by incorporating a reverse osmosis recovery system. Reserve osmosis is a high pressure filtration system which can remove water from the rinse tank solution, thereby reconcentrating the plating solution. The recycled plating solution can then be re-introduced into the plating tank.

A review of EPRI literature, product literature and a consultant's report led to a conclusion that the technology has technical merit and that research should be performed on actual production equipment to quantify the energy impact, operating costs and environmental benefits before a formal option could be developed.

2. **Textile - Reduction of Wastewater Effluent**

The textile industry has opportunities to improve the quality of its wastewater discharge. Several opportunities were uncovered by a consultant to Duke Power in a recent research project, including:

A. Concentrate wastewater from sizing operations and operations and recover polyvinyl alcohol
B. Reduce BOD level of wastewater
C. Remove color from dyeing effluent
D. Recover of caustic

Reverse osmosis, ultrafiltration, heat pump evaporation and ozonation are technologies which could be employed to improve the quality of textile wastewater. The industry is seeing increased regulation and foresees further tightening in the future. Activity in this environmental arena would forestall further erosion of Duke's textile base while making the textile industry more competitive.

An option development team was formed to consider placing an option into the LCP process. The team reviewed technology information, literature on textile applications and customer input.

The team also reviewed a consultant's report to understand the technologies and their applications for the textile industry. Textiles facilities were visited and the team learned that color removal is an area of great concern for the dyeing and finishing plants, however regulations are not yet in place to force industry to make any significant investment for color removal.

The literature and customer review produced interesting results. On one hand there is a need for color removal technology, but no single technology works effectively for all dyeing operations. The team concluded that there is a need to investigate this option, but it is premature to develop an option for integration. EPRI has tentative plans to perform research on this subject and Duke will seek active involvement in the project.

Appendix VI-7: DSM RD&D Projects

This section provides a brief history of RD&D and a synopsis of some of the current technology RD&D projects undertaken to support demand side planning activities at Duke.

During 1990, serveral issues of strategic importance to the future of Duke were considered by task force groups charged with presenting data, alternatives, and recommendations about each issue. These issues included demand-side technology, marketing and competition, among others. This process indicated that demand-side technology could have current and future impacts on many of the issues under consideration.

The demand-side technology task force identified a continuing need for Duke to accelerate development of emerging end-use technologies which meet customer needs and expectations, and to learn more about future end-use technologies which may support Duke's strategic and DSM objectives. The task force concluded that it is necessary and appropriate for Duke to take an active, expanded role in the research, development, and demonstration (RD&D) of these technologies.

In late 1990, staffs and budgets increased to expand and focus on the technology RD&D effort for 1991 and subsequent years. The technology RD&D process enhances Duke's planning efforts by focusing the attention of demand-side planners, engineers and management on the needs and expectations of our customers.

The first product of Duke's commitment to the technology RD&D process was a planning tool called the Strategic Customer Technology Development Plan (SCTD). The 1991 SCTD Plan was forwarded to senior management and selected middle management at the beginning of the corporate budget process for 1992-1993. A copy is available upon request. Subsequent annual revisions of the SCTD Plan will serve to document our evolving technology RD&D process and its contribution to success in meeting the needs and expectations of our customers and in attaining strategic and DSM objectives.

Descriptions follow for ten ongoing RD&D projects which align with Duke's DSM strategy.

The first four projects feature technology targeted at longer-term DSM applications; i.e. those approximately 8 to 10 years from field implementation. The next four mature technologies and planning tools to support DSM applications 5 to 7 years away. The final two projects presented here feature DSM tools which will be in use 2 to 3 years from now.

Title: Utility Information Gateway Development

The purpose of this project is to design, document and develop a working prototype of a wide area network (WAN) to local area network (LAN) modular pole- or pad-mounted utility information gateway (UIG). Such a gateway will serve as an integral part of an energy management / real-time, interactive metering system by coupling the Integrated Services Digital Network (ISDN) WAN and Consumer Electronics Bus (CEBus) LAN systems.

Dedicated hardware and software will be developed to allow a utility's energy control / billing computer to communicate, via the UIG, with a CEBus-ready meter and other CEBus control and data acquisition modules located on the distribution system both on and off the customer's premises. The prototype system will be used to demonstrate real-time electrical demand-side management such as distributed energy management and load control, and remote, automatic meter reading and programming.

Title: Intelligent Electric Meter Demo / Evaluation

This project is phase II of the Utility Gateway Information Development project. This phase will design, document and develop a working prototype "smart" electric meter. In addition to automating and integrating such traditional functions as meter reading and load control, such an intelligent meter will serve as the cornerstone for real-time electricity pricing and customer communications.

In the prototype system to be demonstrated, time of day pricing tables will be generated by the utility energy control / billing computer, sent over the T&D lines, through the UIG, to reside in the intelligent meter until changed. The CEBus residential EMS LAN will make decisions about energy consumption, cycle appliances, etc., based on communication with the meter and interpretation of the resident pricing information.

Title: Intelligent Appliances for Residential EMS / DSM

The purpose of this project is two-fold: 1) to develop the software and control strategies for an interactive home energy management system (EMS) for use with the intelligent CEBus-ready electric meter, and 2) to select and modify a group of residential appliances to permit control of their operations via the home EMS.

The appliances to be modified will include HVAC hardware, refrigerators and freezers, hot water-producing appliances, clothes dryers and washers, and kitchen ranges / ovens. The modifications will include integration of CEBus-ready microchips into the control circuits of selected appliances. The DSM potential for this prototype system is enormous, and is dwarfed only by the possibilities it offers for improved customer satisfaction and home energy efficiency.

Title: Solar / Photovoltaic (PV) Technology Demo / Evaluation

The purpose of this project is multi-fold: a) to demonstrate utility peak load reduction using modular solar / renewable energy units capable of providing 5 to 15 KW per customer site, b) to demonstrate how this modular technology can be retrofitted to existing customer sites, c) to locate a number of such systems in various NC and SC climatic locations and economic conditions, and d) to obtain and evaluate performance data on all major system components over a complete heating and cooling season.

This project will provide a greater understanding of solar / PV technology applications and may indicate the direction in which to move in order to incorporate such end-use technology into utility DSM and marketing strategy.

Title: Integrated Residential Energy Systems Demo / Evaluation

The purpose of this project is to conduct a program of research, demonstration and evaluation, and dissemination of information to the public on cutting-edge residential building shell design practices and efficient technologies.

Four houses will be constructed to incorporate increasing levels of energy-efficient design and grades of appliances in each successive house. The first three homes will be in the medium price range incorporating commercially available technologies. The fourth will be constructed using state of the art building concepts, alternative heating, cooling and lighting systems, and will incorporate a CEBus-ready home EMS.

This project will demonstrate advanced and high-efficiency design concepts and end-use technologies. The Mechanical Engineering Dept. at Clemson University will assist the SC Energy R&D Center in the construction, instrumentation and monitoring of the houses. Results will be used to produce learning/instructional tools for Duke residential reps and their customers to use in making best energy related decisions when constructing/renovating homes and offices. A television series, called "The Energy House", is also planned to document all aspects of this research community.

Title: Cool TES Add-on System Field Tests

The purpose of this project is to demonstrate a prototype cool thermal energy storage (TES) system in a residential application in the Duke Power service territory. As one of several sites to be monitored nation-wide, a cool TES system will be installed in a Duke Power customer's home and monitored for two years. The system to be evaluated is the Lennox Cool Thermal Energy Storage (CTES) system, a prototype, add-on system which is designed to work with virtually any existing split-system heat pump or air conditioner.

TES applications shift energy consumption from on-peak periods to off-peak periods, a DSM objective. An evaluation of the performance and economics of this unique add-on system may lead to wider acceptance of this DSM option and to an eventual DSM program, possibly coupled with real-time pricing via the intelligent meter under development.

Title: Residential Dual Fuel Heat Pump Field Tests

The purpose of this project is to evaluate the operation of a dual fuel heat pump (DFHP) in a residential application in the Duke Power service territory. As one of six sites to be monitored nation-wide by EPRI, a single package DFHP produced by Goodman Industries is in operation at a Duke Power customer's residence.

Benefits expected from this project include confirmation of other research which indicates that dual fuel heat pumps operate more cost-effectively than independent electric heat pumps or gas furnaces. In addition to the improved energy value for DFHP customers, DFHP technology offers winter peak-reduction capability. This is not a current issue at Duke Power, but this DSM option may prove necessary in the future.

Title: Industrial DSM / Efficiency Audits Program

The purpose of this project is to develop an industrial customer efficiency methodology which focuses on general operating issues, process technology and energy utilization, and which can be applied to a wide variety of industrial plants. The methodology will seek to include a strong energy conservation / DSM element that incorporates DOE's national Energy Analysis and Diagnostic Centers program, and to create a dynamic audit process that can be updated based on new data from case studies.

This work will support a methodology for industrial DSM that integrates the needs of the customer with the objectives of the utility. This methodology will address not only energy efficiency but also environmental and productivity issues facing our industrial customers.

Title: DSManager Software Model Upgrade

The purpose of this project is to enhance the DSManager software program and associated tools in order to automate additional tasks and accelerate the rate at which information can be processed. DSManager is a personal computer tool that facilitates DSM technology / program analysis, and integrated resource planning. DSManager and associated software tools allow Duke Power planners to assemble a cohesive portfolio of DSM programs and to maximize planning resources.

Proposed enhancements will also focus on streamlining documentation and allowing DSM options information to be organized in forms that facilitate interpretation by demand-side planners.

Title: IMIS Software Upgrade

The purpose of this project is to develop enhancements of and updates to the Industrial Marketing Information System (IMIS) software program to facilitate greater use of this system to l) identify and meet Duke's industrial customers' needs in areas of environmental compliance and 2) to identify and target opportunities to improve process efficiencies and to implement DSM objectives.

The proposed Update Module will expand the IMIS SIC coverage, revise IMIS data sets to reflect 1992 energy and market data, and add 3-digit SIC level industry segments to the data base. An Environmental Module and a "20 Questions" Module (i.e., a customer interview process) are also proposed as part of this project.

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Appendix 9.

Appendix IX-1: MODELS USED IN INTEGRATION PLANNING

Appendix IX-1 includes a brief description of the models used in the integrated planning process.

PROVIEW

PROVIEW is a resource optimization planning model that can combine both demand-side and supply-side alternatives into one integrated resource plan. This is accomplished using planning parameters such as: production costs, capital costs, and reliability constraints. PROVIEW models the operation of a utility system and determines the cost and reliability effects of supply-side and demand-side options that modify or interrupt the load. It then ranks each plan according to criterion specified in an objective statement (based on minimization of total resource cost, utility cost, societal cost or rates) and reports both the optimal and suboptimal plans.

Demand-side alternatives are analyzed using hourly chronological load patterns where load data is specified by a typical week, month, etc. Direct load control is similarly analyzed including the effects and constraints of payback characteristics. Supply-Side options are considered using fuel limitations, must run status, maintenance requirements, operating cost, capital costs, etc. Several types of supply-side options that PROVIEW addresses are: Thermal units (including Combustion turbine, Fossil, and Nuclear), Hydro units, and Storage units (i.e. pump storage).

PROVIEW uses dynamic programming in the optimization process. The dynamic programming process can examine all possible combinations of supply-side and demand-side options by creating a "tree" where the paths between states in each year has an associated cost. This allows for a thorough comparison of all alternative plans that are within the specified "tunnel" of constraints. PROVIEW provides the user with various ways to limit the number of options considered. This is necessary due to the exponential growth in states generated as each additional option and each subsequent year are evaluated. Some of these limits include maximum and minimum number (of units) to add, reserve margin, and first year available. This method enables PROVIEW to eliminate options that are not feasible, thereby reducing computer run time for the study.

For each state created in each year, PROVIEW uses the defined system data and performs a probabilistic--load duration curve -- production costing analysis. Supply-side and demand-side (including direct load control) options are included in the production cost. To then determine the optimal and suboptimal plans -- based on the input criterion -- PROVIEW traces back from the last year of the study to the first year of the study. The optimal and suboptimal plans are then ranked by cost, based on the input criterion.

PROMOD III

PROMOD III is a software package that simulates the operation of an electric utility's generating system. The primary purpose is to determine production costs in order to allow projections of future operating expenses. PROMOD III can also be used to evaluate system reliability. Relative reliability is determined by setting a target for loss-of-load hours (hours where demand exceeds supply) and then examining the demand-side options against that target.

Inputs can be as detailed as the user desires. For example, the simplest modeling of a unit may include one capacity state, 100 percent availability, a specified heat rate at the given capacity, and assignment of a fuel. Modeling can also be much more complex by using a polynomial function to define the heat rate curve; assigning 5 capacity states (each with its own availability); specifying mature and immature forced outage rates; assigning cost rates to fixed O&M; variable O&M; maintenance outages; overhaul outages; using multiple fuels and mixtures of fuels; scheduling maintenance; and assigning seasonal capacity derates. These are just some of the options available for modeling a generating unit. Inputs for loads include an hourly load shape and forecasted peaks and energies. Transactions are modeled with inputs such as capacities, energies, costs, schedules, and reserve contributions. Fuel modeling includes the ability to model limited funds and to change costs monthly.

ENPRO - II

ENPRO - II is a PC based, integrated software package designed to accurately simulate electric generating systems. It performs detailed chronological dispatches using hourly load data. These dispatches are based on economics and forced outage conditions at the time of dispatch. The unit forced outages are determined using the Monte Carlo technique.

In order to closely model real world conditions, ENPRO - II does not optimize dispatch using perfect knowledge of future system conditions. Instead, it dispatches with only the data available at the time of each hourly dispatch. To do otherwise could overstate the benefits of most types of generation and produce results that are not achievable in the real world.

In order to generate results close to expected values, ENPRO - II allows multiple iterations of each hourly dispatch. This feature minimizes the effect of any abnormal forced outage condition produced by the Monte Carlo technique. Because ENPRO - II simulates the generating system hour-by-hour, it can perform cost analysis of load management, start-up costs, unit ramping problems, and hourly sales/purchases.

Totally Integrated Planning Spreadsheet (TIPS)

The Totally Integrated Planning Spreadsheet (TIPS) is a Duke developed economic spreadsheet that provides a simplified method to analyze the effects of implementing a DSM program. TIPS provides the benefit/cost ratios presented in Resource Integration (9.0) for the Participant test, Total Resource Cost test, Utility Cost test and the Rate Impact Measure test.

Analysis is performed on both a year-by-year basis and on a present worth of these yearly effects. Present worth numbers are presented in base year dollars. The present worth effects are used to determine the various B/C ratios and include the computation for end-effects.

Inputs involve two types: Base or Global parameters; and Yearly DSM data. The global parameters include but are not limited to:

- Study Period
- Discount Rate
- Fixed Charge Rate
- Capital Costs

Yearly DSM data includes:

- Production Costs
- Change in Generation Capacity
- Fuel Costs
- Marketing Costs
- Equipment Costs
- Customer Direct Costs
- Revenue Change

Given the inputs, TIPS computes the applicable benefit/cost ratios for the various tests in present worth base year amounts. The summary page explicitly presents all benefits and costs and the resulting benefit/cost ratio for each test. A computation for end-effects was included in TIPS.

Appendix IX-2: ECONOMIC TESTS USED IN INTEGRATION PLANNING

The following descriptions of the economic tests used by Duke in the integrated planning process are summaries of the material presented in the "Standard Practice Manual: Economic Analysis of Demand-Side Management Programs" written by the California Public Utilities Commission and the California Energy Commission. For additional details please reference the "Standard Practice Manual".

Participant Test (PART)

The participant test is the measure of the benefits and costs to the customer if they participate in a program. Since customers do not base their decision entirely on quantifiable benefits and costs, this test is not a complete measure of the value a program offers the customer.

Benefits: The benefits in the participant test include:

- Reduction in customer's utility bill(s)
- Any incentive paid by the utility or third parties
- Any federal, state, or local tax credit received

The reduction to the utility bill(s) are computed using the applicable retail rate that the customer would incur. The reductions are considered to be the savings in energy and demand by the participant at the meter.

Costs: The costs in the participant test are all customer direct costs or out-of-pocket expenses. This includes but is not limited to:

- Cost of Equipment or materials
- Sales tax
- Installation costs
- Any ongoing operating and maintenance cost
- Any removal costs less salvage value
- Value of the customer's time to install

Benefit/Cost Ratio:

The Benefit/Cost (B/C) ratio is equal to the sum of all benefits divided by the sum of all costs for a defined period of time. This B/C ratio presents a measure of the rate of return for the DSM program to the participant and a rough indication of the risk. A B/C ratio greater than one indicates a beneficial program.

Rate Impact Measure Test (RIM)

The Rate Impact Measure (RIM) test measures the impact to customer rates due to changes in utility revenues and operating costs caused by a DSM program. Rates will decrease if the change in benefits, including revenues, from a program is greater than the change in utility costs. Likewise, rates will increase if benefits, including revenues, are less than the total costs incurred by the utility upon implementation of the program. This test indicates the direction and magnitude of the change in customer rates.

Benefits: The benefits included in the Rate Impact Measure test are the savings from avoided supply-side costs. These benefits or savings include:

- Avoided supply-side capacity costs including transmission, distribution and generation valued at the marginal cost
- Reductions in the generation production cost
- Increases in revenue to the utility

Costs: The costs associated with the Rate Impact Measure test are all costs paid by both the utility and the participants plus the decrease in revenues to the utility. These costs include:

- Increased supply-side capacity costs including transmission, distribution and generation valued at the marginal cost
- Increases in the generation production cost
- Any credits paid to the participant
- All equipment and materials costs
- Any removal cost less salvage value
- All administrative costs
- All marketing costs
- Any federal, state or local tax credits
- Decreases in revenue to the utility

Benefit/Cost Ratio:

The Benefit/Cost (B/C) ratio is equal to the sum of all benefits divided by the sum of all costs for a defined period of time. A B/C ratio greater than one indicates that rates will decrease due to the addition of the DSM program.

Total Resource Cost Test (TRC)

The Total Resource Cost (TRC) test measures the net costs of a demand-side program as a resource option based on the total costs of the program, including the participant's and the utility's costs. The test represents the combination of the effects of a program on both the customers participating and those not participating in a DSM program. The TRC test is the summation of the benefits and costs in the Participant and Rate Impact Measure tests, where the revenue or bill change and the incentives intuitively cancel. The TRC test is applicable for energy efficient, load shift, and environmental DSM programs.

Benefits: The benefits included in the Total Resource Cost test are:

- Avoided supply-side capacity costs including transmission, distribution and generation valued at the marginal cost
- Reductions in the generation production cost

Costs: The costs in the Total Resource Cost test are all costs paid by both the utility and the participants plus the increase in supply costs for periods with increased loads. These costs include:

- Increased supply-side capacity costs including transmission, distribution and generation valued at the marginal cost
- Increased generation production cost
- All equipment and materials costs

- Any removal cost less salvage value
- All administrative costs
- All marketing costs
- Any federal, state or local tax credits
- Participant direct costs

Benefit/Cost Ratio:

The Benefit/Cost (B/C) ratio is equal to the sum of all benefits divided by the sum of all costs for a defined period of time. This B/C ratio presents a measure of the rate of return for the DSM program to the utility and participant. A B/C ratio greater than one indicates a beneficial program on a total resource basis.

Utility Cost Test (UC)

The Utility Cost (UC) test measures the net costs of demand-side program as a resource option based on the costs incurred by a utility including incentive payments and excluding any costs incurred by the participant. The benefits are similar to the TRC test benefits but the costs are more narrowly defined. The UC test is applicable for energy efficient, load shift, environmental and interruptible DSM programs.

Benefits: The benefits included in the Utility Cost test are:

- Avoided supply-side capacity costs including transmission, distribution and generation valued at the marginal cost
- Reductions in the generation production cost

Costs: The costs in the Utility Cost test are all costs incurred by the utility plus the increase in supply costs for periods with increased loads. These costs include:

- Increased supply-side capacity costs including transmission, distribution and generation valued at the marginal cost
- Increased generation production cost
- Any credits paid to participant
- All equipment and materials costs
- Any removal cost less salvage value
- All administrative costs
- All marketing costs
- Any federal, state or local tax credits

Benefit/Cost Ratio:

The Benefit/Cost (B/C) ratio is equal to the sum of all benefits divided by the sum of all costs for a defined period of time. This B/C ratio presents a measure of the rate of return for the DSM program to the utility. A B/C ratio greater than one indicates the program would benefit the utility's cost situation.

Glossary

AC. Alternating Current

AFBC. Atmospheric Fluidized Bed Combustion

AFUDC. Allowance for Funds Used During Construction

ALWR. Passive Advanced Light Water Reactor

A/C. Air Conditioning

APC. Advanced Pulverized Coal

BACT. Best Available Control Technology

BEA. Bureau of Economic Analysis

BLS. Bureau of Labor Statistics

BOD. Biochemical Oxygen Demand

BTU. British Thermal Unit

B/C. Benefit Cost Ratio

CAA. Clean Air Act

CAES. Compressed Air Energy Storage

CFBC. Circulating Fluidized Bed Combustion

CFC. Chlorofluorocarbons

COMMEND. EPRI commercial end-use energy forecasting software

CP&L. Carolina Power and Light

CT. Combustion Turbine

CWIP. Construction Work in Progress

DC. Direct Current

DSManager. EPRI DSM option evaluation software package. (See Appendix VI- 1)

DSM. Demand-Side Management

EEI. Edison Electric Institute

EGEAS. An optimization planning model

Energy Efficiency.

- **Demand-Side** Reducing energy use without reducing the amenity.
- **Supply-Side** Increasing output while using the same amount of fuel, or maintaining output while using less fuel.

ENPRO. A chronological production costing model (See Exhibit IX-1)

EPA. Environmental Protection Agency

EPRI. Electric Power Research Institute

FERC. Federal Energy Regulatory Commission

FGD. Flue Gas Desulfurization

GWH. Gigawatt-hour (a measurement of energy)

GRP. Gross Regional Product

HELM-PC. EPRI load shape forecasting software product for all customer classes

HTGR. High Temperature Gas-Cooled Nuclear Reactor

HVAC. Heating, Ventilation, and Air Conditioning

INFORM. EPRI industrial end-use energy forecasting software

IPP. Independent Power Producer

IRP. Integrated Resource Plan

IS. Interruptible Service (a DSM program)

KW. Kilowatts (a measure of demand or capacity)

KWH. Kilowatt-hour (a measure of energy)

LCIRP. Least Cost Integrated Resource Plan

LCTS. Lincoln Combustion Turbine Station

LWR. Light Water Nuclear Reactor

MMBTU. Millions of British Thermal Units

MNDC. Maximum Net Dependable Capability

MSW. Municipal Solid Waste

MW. Megawatt (a measurement of demand or capacity)

NAAQS. National Ambient Air Quality Standards

NABE. National Association of Business Economists

NCAEC. North Carolina Alternative Energy Corporation

NCUC. North Carolina Utilities Commission

NOx. Nitrogen Oxides

NRC. Nuclear Regulatory Commission

NSPS. New Source Performance Standards

NUG. Non-Utility Generator

OPT. Duke's non-residential time-of-use rate

Options. Potential DSM Programs or Supply-Side additions

PART. Participants test (See Appendix IX-2)

PC. Pulverized coal

PFBC. Pressurized Fluidized Bed Combustion

PMP. Plant Modernization Program

Pilot. Field test of DSM option on limited basis (See Appendix VI-3.2)

PSD. Prevention of Significant Deterioration

Programs. DSM options offered to the customer

PROMOD. A software package that simulates the operation of an electric utility's generating system (See Appendix IX-1)

PROVIEW. A resource optimization planning model (See Appendix IX-1)

PURPA. Public Utility Regulatory Policies Act

PWRR. Present Worth of Revenue Requirements

QF. Qualifying Facility

Rate Schedule WC. Rate schedule to administer 1/2 price off-peak water heating (See Appendix VI-2)

RDF. Refuse Derived Fuel

REEPS. EPRI residential end-use forecasting software

Resource. Method of supplying, reducing, or displacing a portion of customer needed demand & energy (KW, KWH)

Rider IS. Rate document to administer Interruptible Service Program (See Appendix VI-2)

Rider LC. Rate document to administer Residential A/C & Water Heater Load Control Program (See Appendix VI-2)

Rider SG. Rate document to administer Standby Generator Program (See Appendix VI-2)

RIM. Rate Impact Measure test (See Appendix IX-2)

PSCSC. Public Service Commission of South Carolina

RD&D. Research, Development and Demonstration

SCF. Standard Cubic Foot

SCPSC. South Carolina Public Service Commission

SEER. Seasonal Energy Efficient Ratio

SEPA. Southeastern Power Administration

SHAPES-PC. Energy Management Assoc. end-use energy and load shape software for all customer classes

SIC. Standard Industrial Classification (a government publication)

SCC. Stress Corrosion Cracking

SG. Standby Generator

SO_2. Sulfur Dioxide

STAP. Short-Term Action Plan

Technologies. Generation sources, end-uses, etc. that are potential DSM or Supply-Side options

TIPS. A Duke developed economic spreadsheet (See Appendix IX-1)

TRC. Total Resource Cost Test (See Appendix IX-2)

T&D. Transmission and Distribution

TVA. Tennessee Valley Authority

UC. Utility Cost Test (See Appendix IX-2)

VOC. Volatile Organic Compound

WEFA. Wharton Econometric Forecasting Associates