The Commonwealth Electric Open Planning Project

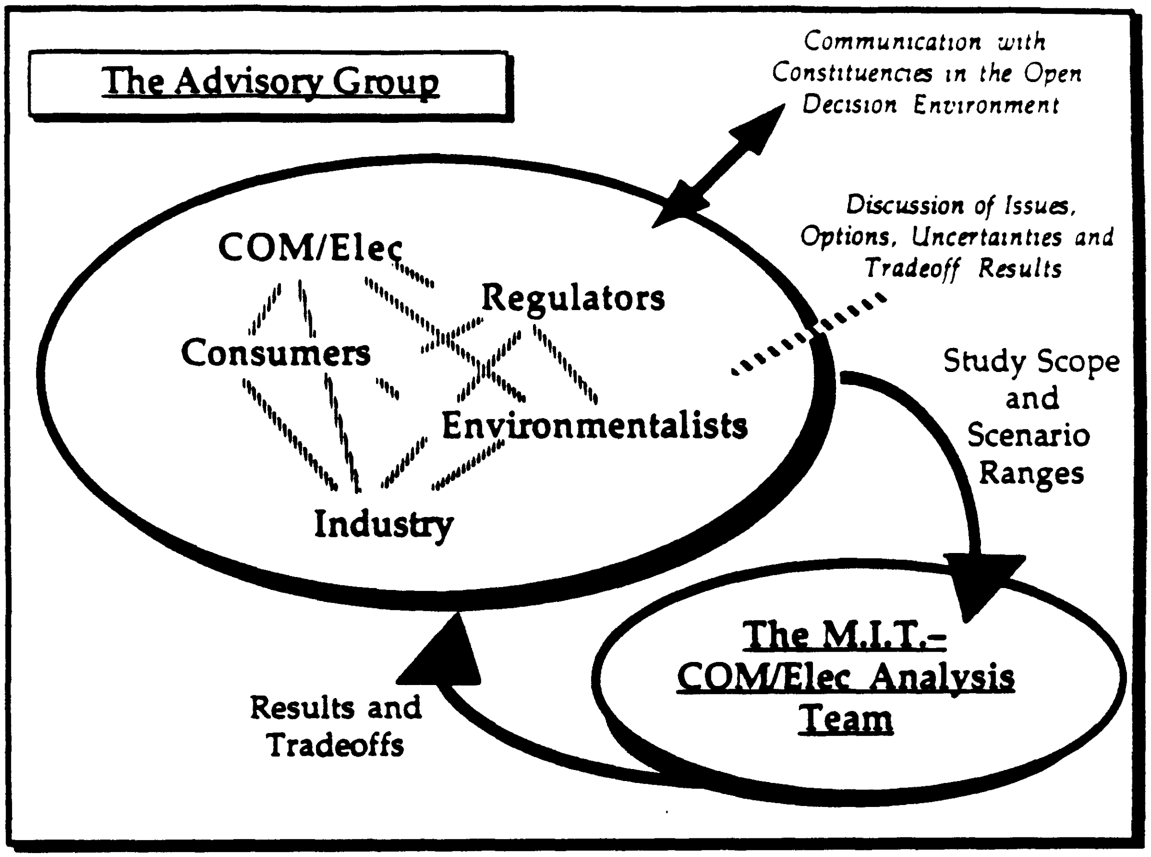
Final Report

by

C. J. Andrews, S. R. Connors, D. L. Greenberg,
W. W. Schenler, R. D. Tabors, and D. C. White

MIT-EL 91-001 January 1991

THE COMMONWEALTH ELECTRIC OPEN PLANNING PROJECT



FINAL REPORT FOR PHASE ONE

JANUARY 1991

ANALYSIS GROUP FOR REGIONAL ELECTRICITY ALTERNATIVES

Dr. Clinton J. Andrews, Mr. Stephen R. Connors,
Mr. Daniel L. Greenberg, Mr. Warren W. Schenler
Dr. Richard D. Tabors, Dr. David C. White

The Energy Laboratory, Massachusetts Institute of Technology
77 Massachusetts Avenue, Cambridge, MA 02139

Table of Contents

List of Figures

List of Tables

Executive Summary

The electric power planning process is complex, involving tradeoffs between many different options with many different impacts. Participants who do not agree on how to value these impacts have difficulty agreeing on their choice of options, which can, and sometimes has, led to regulatory deadlock. This report describes the development, application and results of an Open Planning Process performed by the M.I.T. Energy Laboratory's Analysis Group for Regional Electricity Alternatives (AGREA) for, and with the support and close cooperation of the Commonwealth Electric Company (COM/Elec).

Building consensus in this public policy debate requires rigorous development and analysis of the wide variety of options available, and more importantly, clearly communicating the results of those analyses in a forum where participants in the electric power debate can communicate freely with each other. In order to meet these objectives, the M.I.T. and COM/Elec team has developed an Open Planning Process, involving both an advisory group and an analysis team. The advisory group is composed of the different stakeholders in the planning debate, including consumers, business customers, regulators, community activists, and environmentalists. The analysis team is composed of the M.I.T. analysis group, working in conjunction with COM/Elec personnel.

This Open Planning Process was developed for use in the power planning debate for the entire New England region. This report describes its application to a single utility, Commonwealth Electric. This application is part of COM/Elec's initiative to increase public and customer input into its decisionmaking, while incorporating all supply and demand-side options, their interactions and non-price impacts, as will be necessary under the new regulatory process of "Integrated Resource Management."

The Open Planning Process as it was tested by this project was comprised of an iterative and interactive series of three meetings between four different consumer advisory groups and the analysis team. Once the advisory group was formed, the first meeting concentrated on those issues of concern to the advisory group, and how those concerns could be evaluated. The analysis team took these concerns and structured the technical analysis, forming options and uncertainties into scenarios that were then modeled and analyzed. The second meeting presented the options and uncertainties back to the advisory group for discussion and confirmation. Following their comments, the analysis team took the revised scenarios, modeled them, analyzed the results, and presented them back to the advisory group at the third meeting. The advisory group then attempted to reach a consensus on what type of options should be incorporated into COM/Elecs's long term strategy, based on the system-wide interactions and tradeoffs involved. Based on the full or partial consensus reached, COM/Elec can then structure its own response to Integrated Resource Management process.

This Open Planning Process was developed through a series of meetings, using an initial advisory group composed of COM/Elec personnel. Beginning in June 1989, these meetings followed the general process described above, although the development of the analytic techniques and the open planning process itself required more than three meetings. Meanwhile the analysis team gathered data on the COM/Elec system, modeled initial test scenarios, and constructed the automated computer modeling tools necessary to perform the analysis.

A set of four external advisory groups was then formed of COM/Elec customer "decision makers." These Consumer Advisory Groups corresponded to the COM/Elec's Cambridge, Plymouth, New Bedford, and Cape Cod service districts. A "cross section of leading citizens" were identified by COM/Elec's district service representatives and requested to participate by a letter of invitation. Each of the four groups met for the series of three meetings and participated in the Open Planning Process steps outlined above. The first series of meetings took place the first two weeks in March, 1990 and identified four major areas of concern - environmental impacts, cost of service, reliability of service, and efficiency. The advisory groups reviewed the option-sets and uncertainties forming the scenarios at the second series of meetings in late April, and a set of preliminary results were shown to acquaint members with different methods of presentation and to check with members on which measures, or attributes of the results best reflected their concerns on various issues. The final set of meetings took place in mid-May, where the participants were presented with a full set of results and requested to reach a consensus given the options considered. Based on the results presented, an additional set of scenarios were chosen. These were modeled in June and July, and are presented as part of this report.

The scenarios modeled were formed by combining different utility choices or options and different uncertainties about future events beyond utility control. Supply and demand-side options were each combined into separate option-sets that represented reasonable possibilities of what COM/Elec could implement itself and with its customers. Supply and demand-side option-sets were then combined into strategies. Uncertainties were also divided into separate possibilities (e.g. low, base, and high load growth), and these uncertainties were then combined to form different futures. Finally, strategies and futures were combined to form scenarios.

Within this framework, the supply-side option-sets incorporated three major choices. First was the choice of technology mix (the blend of new technologies COM/Elec can use to meet future demand). The analysis team modeled eight different technology mixes, including different combinations of gas-fired, coal-fired, repowering, nuclear, and photovoltaic technologies. Second was the choice of supply-side operation, specifically fueling oil-fired capacity with low sulfur Oil 6 vs.

the high sulfur Oil 6 currently burned in their plants. Third was the choice of supply-side planning; scheduling new capacity to meet a base target reserve margin of 23% vs. a higher target reserve margin of 30%.

The demand-side options were combined into two option-sets, the Collaborative process option-set (COM/Elec's current level of demand-side management programs), and an Enhanced Collaborative process option-set.

Futures were combined from three uncertainties; 1) low, medium and high load growth, 2) low, medium and high customer response to DSM programs, and 3) medium and high natural gas prices relative to base oil prices.

All possible combinations of these different strategies and futures gave a total of 1152 scenarios which were modeled using the LMSTM production costing model. For each scenario, the analysis team calculated over sixty different attributes to use in measuring and understanding the four consumer advisory groups' concerns. Based on these concerns of environment, cost, reliability, and efficiency, a subset of primary attributes were designated to measure cost of service, rateshock, total sulfur dioxide and carbon dioxide emissions, and reliability.

Results for these scenarios told a number of stories. The predominant stories are listed below for the major choices.

- Technology Choice Option-Sets - The choices of technology mix, fuel, and reserve margin had major effects on cost, emissions and reliability. However these impacts were mixed, with each choice having good and bad effects for different environmental, cost, and reliability attributes. For this reason, no set of choices was a clear winner, but several appeared most often as dominant choices for different attribute tradeoffs. Repowering and Coal & Repowering did well for cost vs. SO_2 and cost vs. CO_2, while the Nuclear & Gas dominated for SO_2 vs. CO_2. Photovoltaics and refueling the Canal plant with coal gas were inferior choices.

- Demand-Side Option-Sets - The Enhanced Collaborative programs option-set was a clear winner over the Collaborative programs option-set for both cost and emissions. Increasing Demand-Side Management measures was cleaner and cheaper for most futures, but movement in the results was small compared to other options.

- Fuel Oil Sulfur Content - Requiring the use of low sulfur Oil 6 made a major and consistent reduction in SO_2 emissions for all supply-side option-sets, and the reduction was cheaper than that by any choice of technology mix.

- Target Reserve Margin - Increasing the reserve margin yielded significantly higher reliability, whether from choice of higher target reserve margin, or from linkage to load growth or technology mix option-set. Cost for this benefit was relatively low, due to increased generation from newer, cleaner and more fuel efficient plants.

The analysis team draws the following conclusions about the Open Planning Process for the policy planning and technical analysis results.

As a public policy planning process, this project succeeded in its goals "to provide integrated resource planning assistance" and "to enhance planning processes and develop a framework for useful public discussion of utility planning issues." The process developed was successful in eliciting participants' relative concerns about major issues, generating significant new alternative options, and receiving participant feedback. The modeling effort was successful in automating analysis so that meetings could be held on a reasonable schedule. Results in achieving consensus were mixed. Where clear winning options were revealed, consensus was possible, but where difficult tradeoffs existed, more time and possible alternate strategies were needed. Despite sometimes limited attendance, the advisory group meetings generated significant positive results in goodwill, enthusiasm, and a better understanding of the complexities and tradeoffs of the planning process.

The results of the technical analysis led to the following overall conclusions.

- There must be a balanced consideration between generation and end-use efficiencies to obtain the most good from new capital expenditures. Concentrating on either supply or demand options to extremes may reduce benefits.

- Analysis of new options must take into consideration their interactions with the existing system and with each other, rather than simply looking at their individual technology specific characteristics.

- Systemwide analysis must be extended to strategies that contain specific components related to system operation options. Choice of fuels and other planning and operating policies can be as important as choice of new supply or demand investment.

Both policy process and technical analysis results confirm the value of the Open Planning Process in gathering concerns from the public and revealing back to them how power planning options interact on a systemic basis with tradeoffs between different attributes. The M.I.T. Analysis Group for Regional Electricity Alternatives thanks Commonwealth Electric for the opportunity to work with them in developing this Open Planning Process, and looks forward to the process being of continuing service as COM/Elec seeks to meet the requirements of the Integrated Resource Management process and to better serve its customers.

1.0 Introduction

The electric power planning process involves making choices among options that have significant cost, environmental, reliability, and other impacts. Participants in the electric power planning debate differ widely in the way that they value these impacts, and therefore differ in the choices they would make. Discussions which have considered only a single issue such as cost or air emissions, or which have valued different issues with a common denominator, have had only a limited impact on electric power problems facing the region. To achieve the desired impacts, all participants must acquire a better understanding of the overall picture - an understanding of the relationships between the issues, and the tradeoffs implicit in the variety of options available to improve the way electric service is provided. It is important to look at the electric power system *as* a system, and to understand the interactions within the system. By understanding these interactions, debate can focus on the best available set of options; options which are clear winners or which embody the best possible tradeoffs. This understanding can form the basis for consensus on positive action, not just for today's problems, but to avert future crises.

1.1 Background

Consensus-building on technically complex electric power planning issues is both an analytical and procedural challenge. It requires public explanation of the performance of many options across a variety of uncertain future conditions using credible modeling tools.

Several years ago, a group of Massachusetts Institute of Technology faculty, staff, and graduate students offered to provide the analytic support for such an effort in order to help a deadlocked policy debate get back on track for the New England region as a whole. By early 1988, regulators, environmentalists, utility personnel, and electricity customers started meeting at MIT on a regular basis. Funding from a consortium of regional utilities and industrial customers allowed the group to expand its analytic capabilities, and by 1989 every state in the region was represented on the advisory group for the New England project.

On December 8, 1988, one of the officers of the Commonwealth Electric Company (COM/Elec) attended our presentation to the NEPOOL Policy Planning Committee of the New England Project's first round of regional tradeoff analysis. The following month, Mr. Donald LeBlanc (Vice President, Resource Planning and Development) asked the MIT Energy Lab to help develop an analytic capability at COM/Electric similar to that being developed for the entire region.

This request was motivated by several things. First, COM/Electric had been ordered by the Massachusetts Energy Facilities Siting Council (EFSC Decision No. 86-4) to improve its resource planning method so that (among other things) it would in the future: (1) include demand-side programs using a "level playing field;" (2) plan more thoroughly for contingencies; (3) compare a larger range of generation and non-generation alternatives; and (4) model supply plans in a more plausible manner.

Second, the Massachusetts Department of Public Utilities had issued an Order (DPU 86-36-F) on November 30, 1988 that paved the way towards requiring utilities to use an "all resource solicitation" process within an "integrated resource management" framework, for future resource plans (see discussion of this order in Chapter Five). Two major implications of this order were the need to account for environmental externalities in the planning process, and the need to better integrate demand-side and supply-side planning. The Department was casting around for ideas about the best way to include something as subjective as environmental externality evaluation in a rigorous, reviewable planning framework.

In January 1989 COM/Electric contracted with MIT to provide "integrated resource planning assistance" in order to "enhance their planning processes and develop a framework for useful public discussion of utility planning issues". Specific tasks included reviewing current planning methods, expanding the company's ability to function in open planning processes, developing their multi-attribute tradeoff analysis capabilities, performing public education on utility planning issues, and exploring issues relating to the interactions between the utility and the region.

1.2 The Open Planning Process

The process developed for both the New England project and the Commonwealth Electric project involves the iterative interaction of an analysis team and an advisory group. The advisory group indicates its concerns in the electric planning process. These concerns may be either issues that can be addressed by the choice of various options, or uncertainties about the future which cannot be controlled. Options and uncertainties are defined and combined into scenarios by the analysis team. The data to model these scenarios is then collected and checked, and the software chosen, developed, and integrated to automate the modeling process. The results of the scenario analysis are evaluated statistically and then presented to the advisory group in order to obtain their reactions on the tradeoffs between various issues when evaluating different strategies, and to elicit their preferences on current or improved strategies which should also be considered in the analysis.

For the Commonwealth Electric project, the analysis team was composed of the MIT Energy Lab's Analysis Group for Regional Electricity Alternatives (AGREA), and staff of Commonwealth Electric's planning department. An initial "internal" advisory group was formed, consisting of Commonwealth Electric staff from several departments. Regular meetings with the internal advisory group provided feedback about COM/Elec's concerns, the choice of test scenarios, interim results, and the methods developed to present results and elicit opinions from an "external" advisory group.

The process developed for interacting with an advisory group and performing scenario analysis was then employed to bring some of COM/Elec's customers into the planning process, using four external, consumer advisory groups (CAGs). These groups were composed of community activists and decision makers representing the broad range of interests from COM/Elec's four service territories. Through a series of three meetings these consumer groups were asked to express their concerns, to confirm that the scenarios chosen by the analysis team reflected these concerns, and to attempt to reach a consensus based on the tradeoffs and other information presented in the 720 scenarios analyzed in response to their input.

Based in part on consumer input, COM/Electric may then select a strategy (i.e., a specific portfolio of options) to pursue. COM/Elec could then incorporate the consumer advisory groups' preferences into their third party bids to implement specific options, rank proposals, test to see that actual award group projects formed a similarly attractive portfolio as its generic precursor (considering multiple attributes and uncertainty), and sign contracts.

1.3 Organization of the Report

This report presents the methodology and results of the Commonwealth Electric Open Planning Project, and is divided into two main sections. Chapters 2 through 4 present the theory, development, and application of the methodology. Chapters 5 through 7 describe the final set of scenarios analyzed, present the results, and give the conclusions of the report, based on the analysis and experiences with the consumer advisory groups. Appendices A through D present the details of the consumer advisory group participants, the attributes calculated, the LMSTM model inputs and assumptions, and the graphical results.

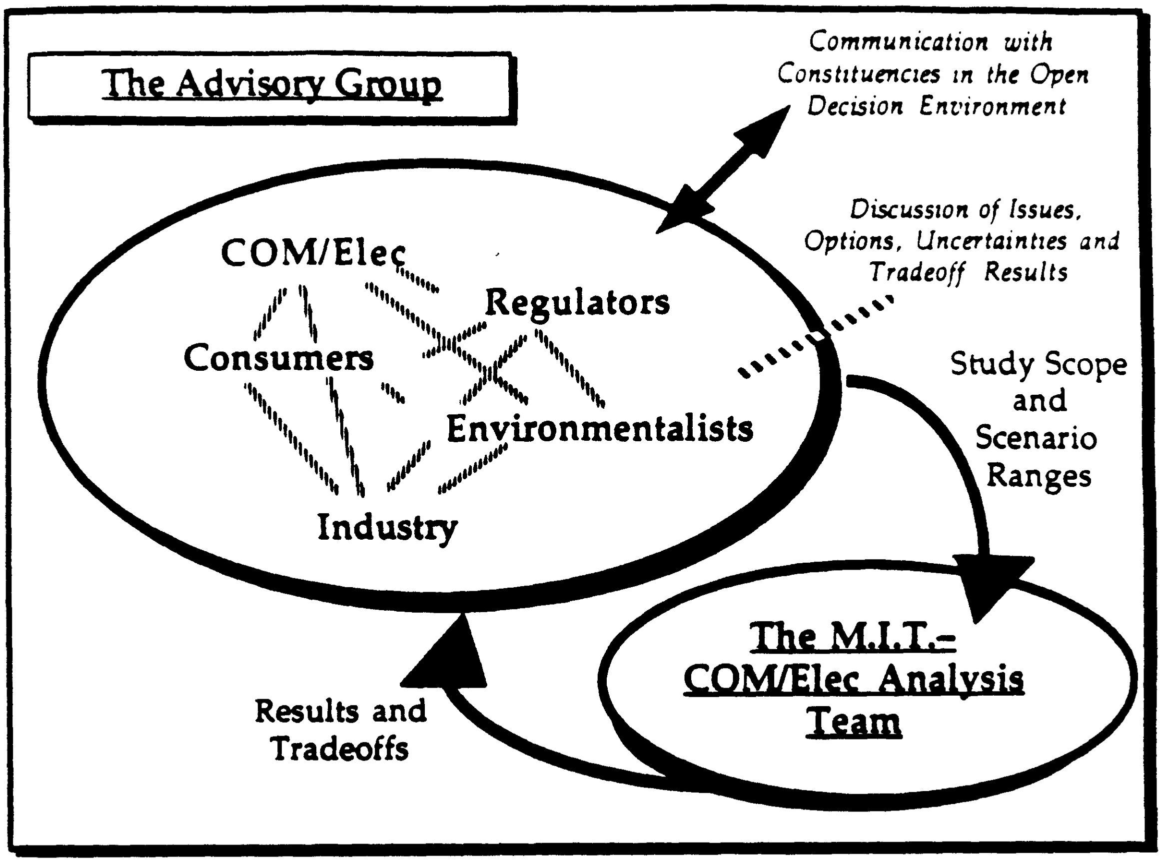
2.0 Theory of Analytic Approach

This chapter describes the approach used by the MIT Analysis Team to interact with the advisory groups and perform scenario analysis in the COM/Electric Open Planning Project. First described is the general method of interaction between the Analysis Team (MIT) and the Advisory Groups (first with the COM/Elec internal advisory group and later with the external consumer advisory groups). Next, the terms used to describe the open planning process are defined - in the order used - as the planning process is followed. Finally, the methods of analyzing, understanding and presenting the results are discussed.

2.1 Advisory Group/Analysis Team Interactions

The interactions between the consumer advisory groups and the MIT analysis team were set up in the form of a *public* public policy analysis exercise. The diverse concerns of participants in the exercise (the advisory group) were channeled into analyzable form by the MIT analysis team and results were then presented back to the advisory group for further consideration. This interactive, iterative approach was intended to reduce the "black box" nature of the analysis work, and to build the advisory groups' confidence in the results. It was also designed to tap the creativity of the advisory group members, in order to invent better options than those currently on the table. Figure 2.1 below shows this Analysis Team/Advisory Group interaction, and the steps involved in the process.

Figure 2.1 - Interaction and Analysis Procedure



1) Identify Issues and Attributes

2) Develop & Analyze Scenarios

3) Understand Tradeoffs & Elicit Consensus

The objective of the group's first meeting with the MIT analysis team was to identify the issues of concern to the various advisory group members, and the attributes by which these concerns may be measured. These were formulated by the analysis team into specific option-sets of actions available to Commonwealth Electric (strategies) and specific sets of uncertainties which mapped out relevant futures of concern. Individual supply-side and demand-side management (DSM) options were solicited from the advisory group as part of the first meeting, but due to their technical knowledge it was the responsibility of the analysis team to construct realistic strategies which addressed the issues important to the advisory group.

These strategies and futures were then presented back to the advisory group to make sure that they accurately reflected their concerns. Appropriate changes were then made, and the strategies and futures were combined into scenarios for analysis by computer. The results of these runs were then reviewed by the analysis team to make sure that they were reasonable and consistent before interpretation of the underlying stories began. These results were then presented to the advisory group in a variety of formats, so that the tradeoffs could be clearly presented and the stories explaining them supported. With this knowledge the advisory group could then attempt to reach a consensus on which strategies produced the most acceptable and robust results in response to their concerns.

Both the advisory groups and the analysis team had certain roles to play within the framework. The responsibilities of the advisory group members in this process were to:

- Identify issues and concerns
- Accept or reject modeling approaches and assumptions
- Express the concerns of their constituencies in discussions about the tradeoffs among options
- Work creatively towards a consensus on the choice of favored sets of options

The responsibilities of the analysis team in this process were to:

- Assemble data and models
- Construct scenarios
- Articulate assumptions, methods, and results clearly (minimize black box modeling)
- Respond to the interests, queries, and proposals of advisory group members
- Assist the advisory groups in inventing better options and packaging them into coordinated strategies
- Assist the advisory group in moving towards a shared understanding of problems, options and system interactions.

The interactions between the advisory groups and the analysis team were structured so that three steps carry them through a full iteration of the process. These steps are listed below, with step three described in detail in Section 2.3.

1. **Identify issues** to focus the analysis upon, and **attributes** by which to compare the performance of different strategies.

2. **Develop scenarios** examining the performance of combinations of options (strategies) across a variety of uncertain future events (futures). Learn about their behavior in the context of a complex electric power system, and test the credibility of the analysis by sharing interim results.

3. **Explore the tradeoffs** between strategies, given the uncertainty about the future, and the multiple-attribute impacts of each strategy as revealed by the analysis, and **understand preferences** of different stakeholders for the various strategies.

2.2 Definition of Terms

Even the brief description above has used a handful of terms that have specific meanings in the context of the open planning process. These terms are defined here so that their consistent use will clearly understood.

Concerns - Any concern which a member of the advisory group has about an aspect of the electrical utility planning and operation problem. Concerns which reflect desired goals in operation are referred to as issues. Concerns over uncontrollable events such as changes in fuel prices or the customer response to company sponsored DSM programs are referred to as uncertainties.

Issues - An issue is any concern about the utility planning problem which can be controlled by a choice or decision in the plan. For example, cost, emissions, and reliability of service are all issues which are influenced by planning decisions. Issues may be *influenced* by factors which cannot be controlled, called Uncertainties (defined below).

Attributes - An attribute is some measure by which performance relative to some issue can be determined. For example, air pollution is an issue which can be measured by attributes such as tons of sulfur dioxide (SO_2) or carbon dioxide (CO_2) emitted over time. The choice of attributes to measure various issues is an important task. The issue of cost can be measured by total dollars spent to provide electrical service over the study period, by the discounted present value of those dollars, by the cost per kWh paid by the consumer, or by some cost of service which accounts for energy services provided by utility DSM measures as well. In addition, volatility of cost may also be an important factor. The way an issue is resolved is, in part, determined by the way the problem is defined and measured.

Uncertainties - An uncertainty is a specific concern about the future which cannot be controlled. For example, electrical load growth is an uncertainty which depends on economic growth, and which cannot be accurately predicted. Uncertainties are analyzed by choosing several values (e.g. low, base, or high load growth), and modeling utility plans for all of them.

Futures - A future is defined as some combination of uncertainties. For example, a specific future may be composed of high load growth, high fuel prices, and poor public response to DSM measures. The number of futures is given by all possible combinations of the uncertainties (e.g. 3 load growths x 3 fuel prices = 9 futures).

Options - An option is a specific action which the utility can choose to take. For example, building combustion turbines or subsidizing household weatherization are both options.

Option-Sets - Because there are a *very* large number of possible options, they are combined into programs of combined options called option-sets. These are generally divided into supply-side option-sets (such as a mix of new gas and coal generation technologies) and demand-side option-sets (which combine different DSM programs like appliance standards, new building standards, etc.).

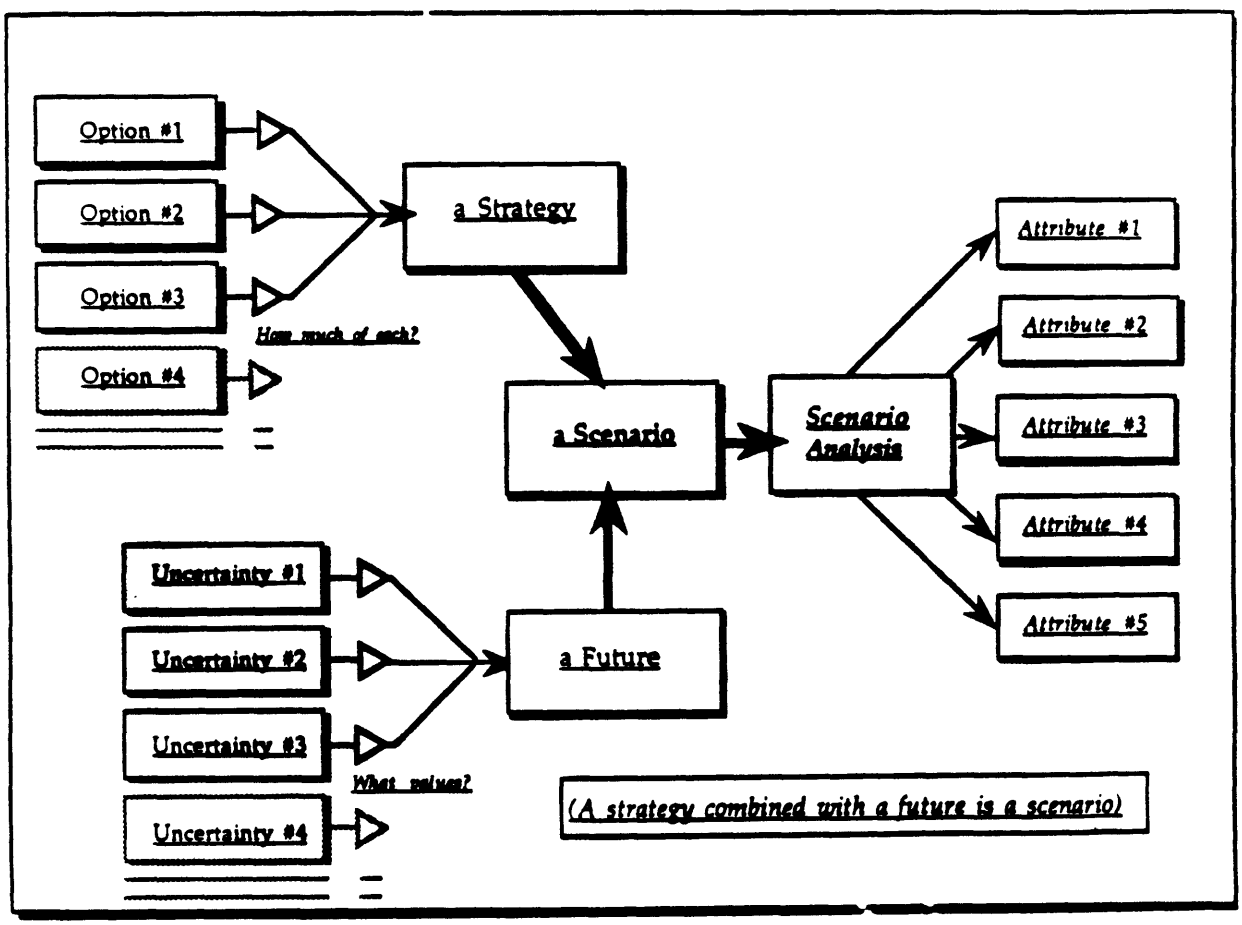
Strategies - Option-sets are combined into strategies, as uncertainties are combined into futures. The number of strategies is determined by all the possible combinations the individual option-sets (e.g. 10 supply-side option-sets x 2 demand-side option-sets = 20 strategies).

Scenarios - Strategies and futures are then combined into scenarios. However, the number of scenarios may not be simply the number of strategies multiplied by the number of futures. In some instances, combinations of strategies and futures may be meaningless (for example, a strategy without any DSM programs could not be combined with a DSM program cost overrun uncertainty).

This process of combining individual uncertainties and options into scenarios is shown in Figure 2.2. It should be noted that for graphical clarity, this diagram omits the intermediate step of forming option-sets from options before combining them into strategies.

The number of computer model runs which must be performed is generally determined by the number of scenarios, although some calculations (usually financial) may be done afterwards. This means that the choice of option-sets and uncertainties must balance the number of possible future plans which can be analyzed against the time the analysis team has to evaluate them. Increasing supply-side option-sets from 10 to 12 will increase model runs by 20% while introducing a new uncertainty will double the runs required.

Figure 2.2 - Scenario Construction



2.3 Analytic Methodology

Once model runs are complete and the data base of input and output results has been assembled, the task of understanding these results still remains. The multiple-attribute results of the scenario analysis must be systematically evaluated in a way that provides useful information to the participants in the open planning process. It is the task of the analysis team to understand and present both the results of the analysis and the underlying stories/explanations contained in those results, in a form that is both conceptually and graphically comprehensible to the advisory group. This analysis has three primary goals in informing the advisory group; 1) to develop in them a shared understanding of the tradeoffs involved in different choices, 2) to help them invent better strategies than are currently on the table, and 3) to seek their informed consensus on a course of action.

There are two major steps in the tradeoff analysis effort:

1) **Explore system behavior** by observing the the impacts of uncertainties, the single attribute impacts of different option-sets and strategies, and the multi-attribute tradeoffs between strategies, for a variety of possible uncertain future conditions. Develop better strategies based on this information.

2) **Elicit participants' preferences** by observing which strategies interest each party, what uncertainties concern them, and how they weigh the various attributes relative to one another. Develop strategies with the potential for consensus based on this information.

Both of these steps are explored below, although there is more emphasis is on the first step of building analytical understanding which must underlie the presentation, and less on the preference elicitation and consensus building process which follows.

Exploring System Behavior.

In general, the scenario analysis process produces such an overwhelming number of results that they must be interpreted using a relatively powerful statistical software package (such as Systat™, which we used, or SAS). Understanding the graphs produced by such packages can be aided by asking a structured series of questions.

1) Single Attribute Analysis. The first step is to graph single attributes as they vary by both 1) uncertainty, and 2) option-set. These may be either individual uncertainties or option-sets (e.g. by load growth or reserve margin), or combined uncertainties or options-sets (these may be fewer than a complete future or strategy). These graphs show the attributes' absolute and relative magnitudes and their variability. The following questions should be asked.

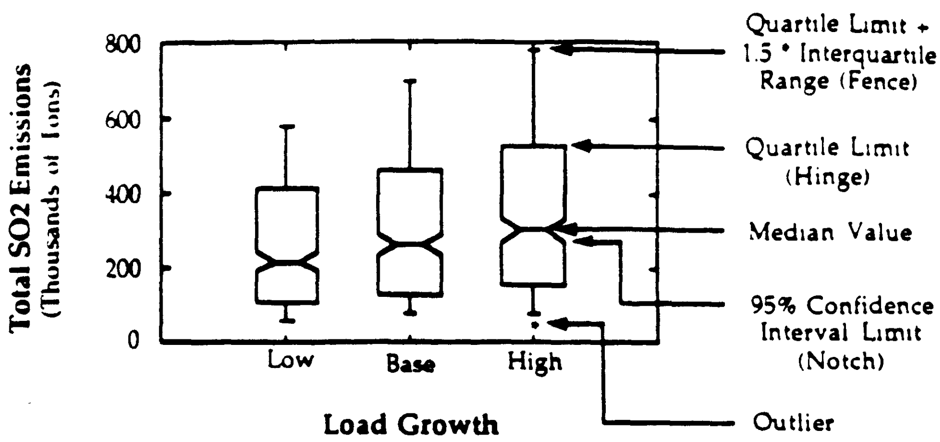
   a) Over what range do the attributes vary?
   b) How relevant are the different uncertainties?
   c) How different are the various futures?
   d) How consistent is the performance of each option-set across various possible futures?
   e) How consistent is the performance of each strategy across various possible futures?
   f) How sensitive are particular strategies to individual futures?
   g) How do individual options perform along various attributes?
   h) How does each option-set perform along various attributes?
   i) How does each strategy perform along various attributes?

In general, the process is one of discovering trends and explaining variability. Do these trends vary in the direction you expect? Are the trends consistent for comparable option-sets, or across different futures? Do the trends reverse, or are there exceptions in some cases? Do the trends established by single option-sets or uncertainties show up consistently when you look at a combined future or strategy? What is the relative size of various trends (especially competing or reversing ones)? Can variability be explained? For example, are variations in emissions explained by relative changes in fuel prices, or consistently low for nuclear supply options? Figure 2.3 gives an example of the statistical output in the graphical form called a box plot, along with its interpretation.

In the process of developing stories which explain these results, it may be useful to look at the correlation coefficients for different attributes and scenario characteristics. Although correlation does not necessarily imply causality, a strong correlation (e.g. high SO_2 emissions are highly correlated with high sulfur Oil 6 consumption) may help explain how the system behaves.

Figure 2.3 below shows a sample single attribute graph for total SO_2 emissions versus load growth. This graph is a called a box plot, and the different statistics it shows are labeled with arrows. This information can also be shown with column charts or other forms of graphs that show averages, maxima, minima, etc..

Figure 2.3 - Single Attribute Graph (Box Plot)



The central line on each notch shows the median value of the distribution (half the values are above the median and half below).

The end of each box is the quartile limit (or hinge). For the upper quartile one quarter of all values are above this line and three quarters below, and vice versa for the lower quartile limit.

The notch on each box shows the 95% confidence interval limit. If the notches on two boxes do not overlap, then the probability is 95% that the median values are different. For example, the low and base notches overlap so the median values shown have less than a 95% chance of being different, but the low and high notches do not overlap and therefore the median values are significantly different with over a 95% confidence.

The outer limit bar (or fence) is given by the most extreme value within the range between the upper (or lower) quartile limit and that quartile limit plus (or minus) one and a half times the interquartile range. That is, the value of the upper fence equals the maximum value between the upper hinge value and that value plus one and a half times the difference between the upper and lower hinge values.

If there are values in the distribution beyond the fences, they are called outliers and shown with asterisks or stars. The outlier shown above was not in the real results, but added for the purpose of showing an example.

2) Multi-Attribute Analysis. Due to cognitive limitations, it is only possible to examine the tradeoffs between three attributes (in three dimensions) at a time, and graphic presentation usually limits this to tradeoffs between two attributes simultaneously. Thus, multiple attribute analysis is normally performed as a succession of pairwise tradeoffs between numerous attributes. The task of evaluating strategies using multi-attribute analysis can be structured by following the steps below.

a) Observe the performance of strategies - considering multiple attributes.
   i. How does each strategy perform for different attribute pairings?
   ii. How consistent is the performance of each strategy across various possible futures?
   iii. How does each strategy perform considering all attributes?

b) Observe the performance of the system.
   i. Do different attributes correlate with one another?
   ii. Do some attributes explain others?

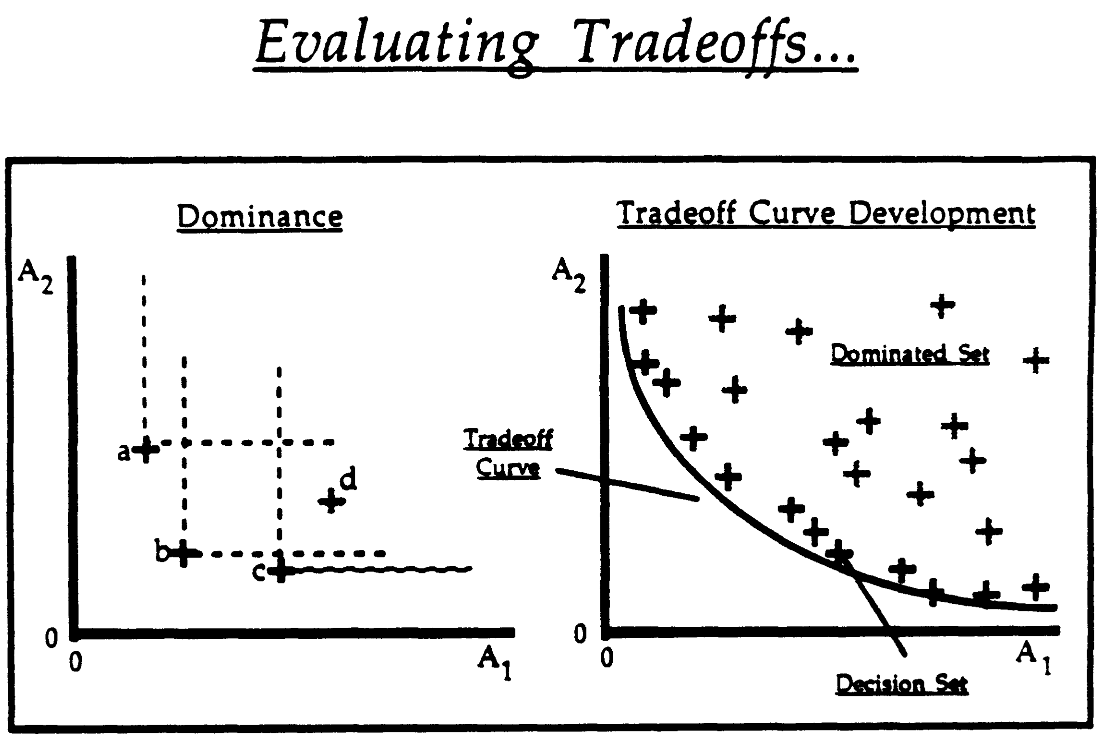
c) Invent better strategies and explore more relevant uncertainties.
   i. Based on what we have learned about the system's behavior, which additional strategies need to be evaluated?
   ii. Are there other uncertainties to consider?

Repeat the steps above if necessary.....

Several concepts related to multi-attribute tradeoff analysis need to be discussed and illustrated. The first and most important is the concept of dominance. A strategy is said to dominate another if it is better or equal in every regard or for every attribute. All strategies which are dominated by some other strategy are members of the dominated set, and all strategies which are not dominated are members of the decision, or dominant set.

These definitions are illustrated by Figure 2.4 below. Strategies 'b' and 'c' dominate 'd' but not each other for the two attributes shown. Strategy 'a' does not dominate 'd' and is not itself dominated by any other strategy shown. Because the dominated set contains strategies which are clearly worse in every way than at least one other, the strategies which form the decision set are the only ones which are worth arguing about.

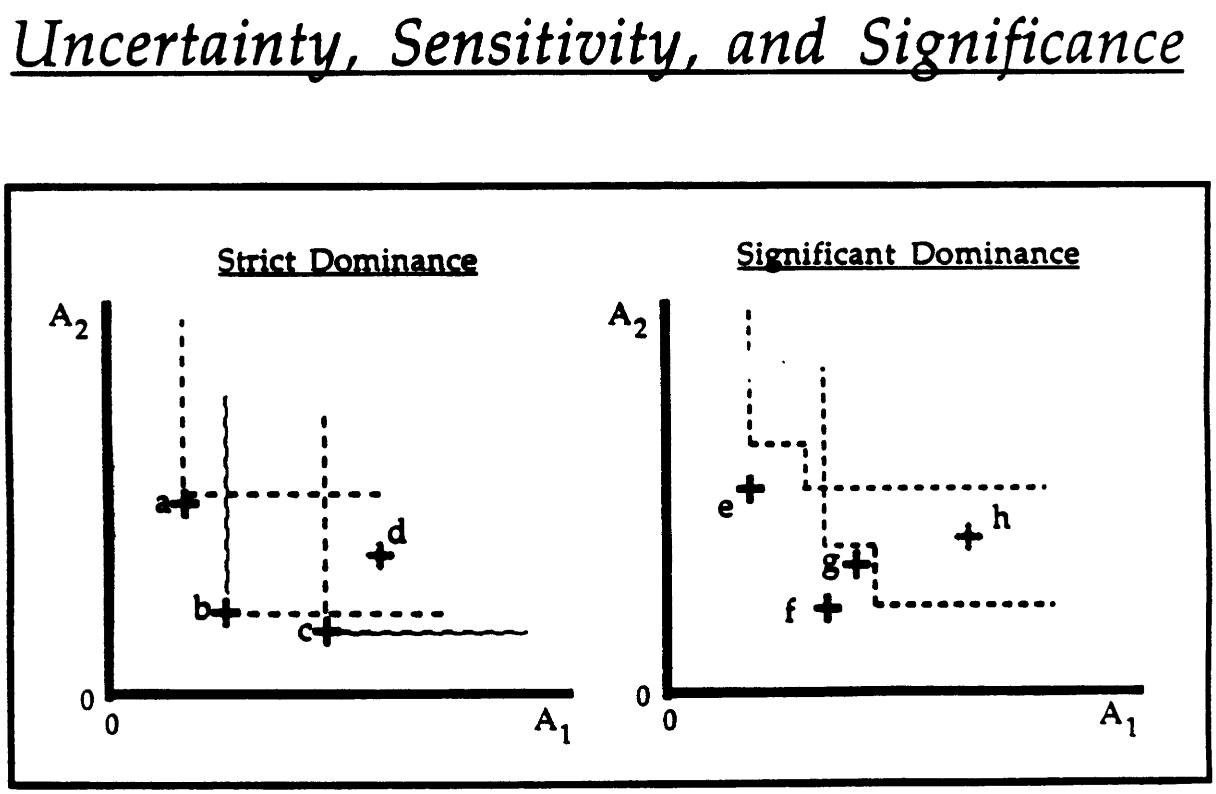
Figure 2.4 - Evaluating Tradeoffs



This discussion assumes that the value of each attribute is exactly known for each strategy. However, these values may not be exact due to sources of error like uncertainty in modeling assumptions. This raises the concepts of uncertainty, sensitivity, and significance as they relate to tradeoff analysis. These concepts are illustrated in Figure 2.5 below.

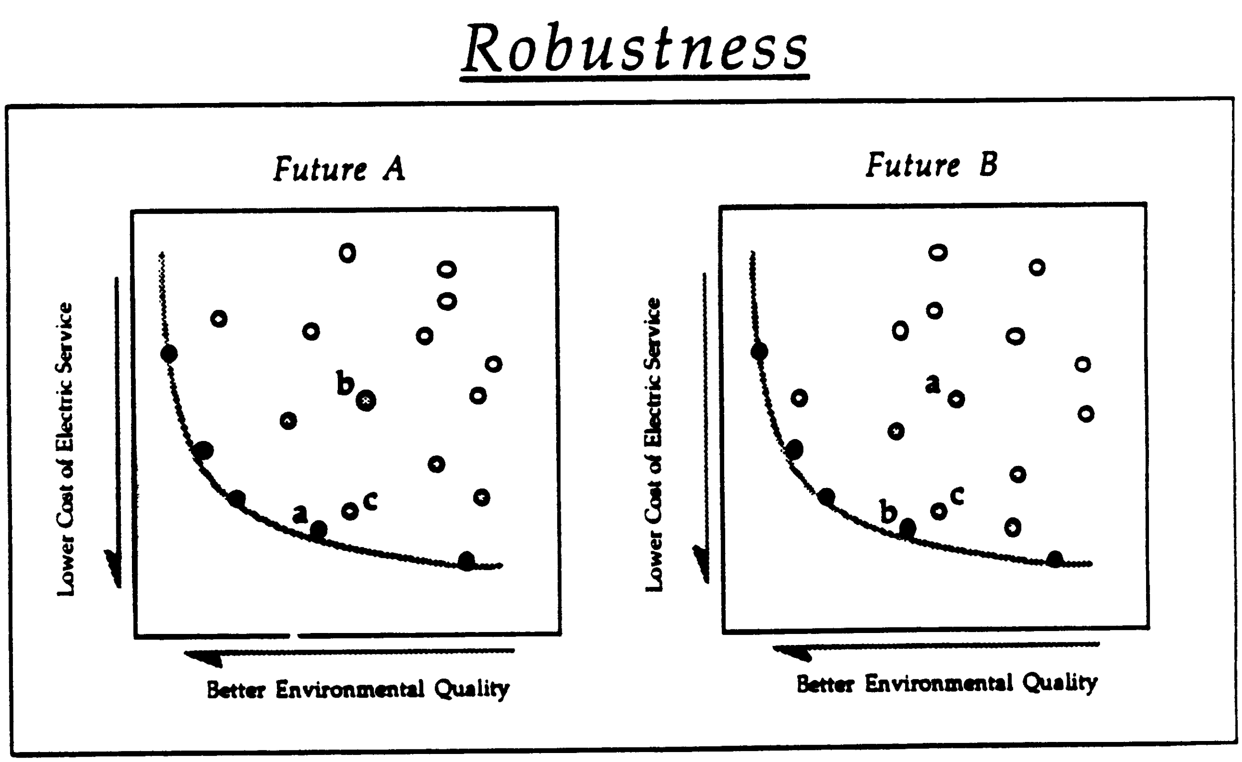
The graph on the left shows each strategy as a single point in multi-attribute space, with all three points forming a decision set in the form of a tradeoff knee. The graph on the right shows how dominance works under uncertainty – there is a range surrounding each point representing the uncertainty in its coordinate values. Thus, while strategy 'f' significantly dominates 'h', it does not significantly dominate 'g' because 'g' lies within the range of uncertainty. Different parties' sensitivities to changes in attribute values could lead to the same effect – the difference between strategies 'f' and 'g' may be functionally irrelevant to some parties – again making the difference insignificant.

Figure 2.5 - Uncertainty, Sensitivity, and Significance



The tradeoff curves shown above are all for a single future which is considered fixed or certain. In the open planning process, each strategy is modeled for many different futures. This leads to the important concept of robustness. A robust strategy is one that performs well under a range of futures. Under a single attribute analysis, this may be seen where a strategy has a good value for some attribute and a low variance across the range of futures. Under a multi-attribute analysis, a robust strategy will be one that is consistently on or near the tradeoff curve. Robustness is illustrated in Figure 2.6 below. In this example only strategy 'c' is considered robust, as both 'a' and 'b' moved well away from the tradeoff curve in at least one future.

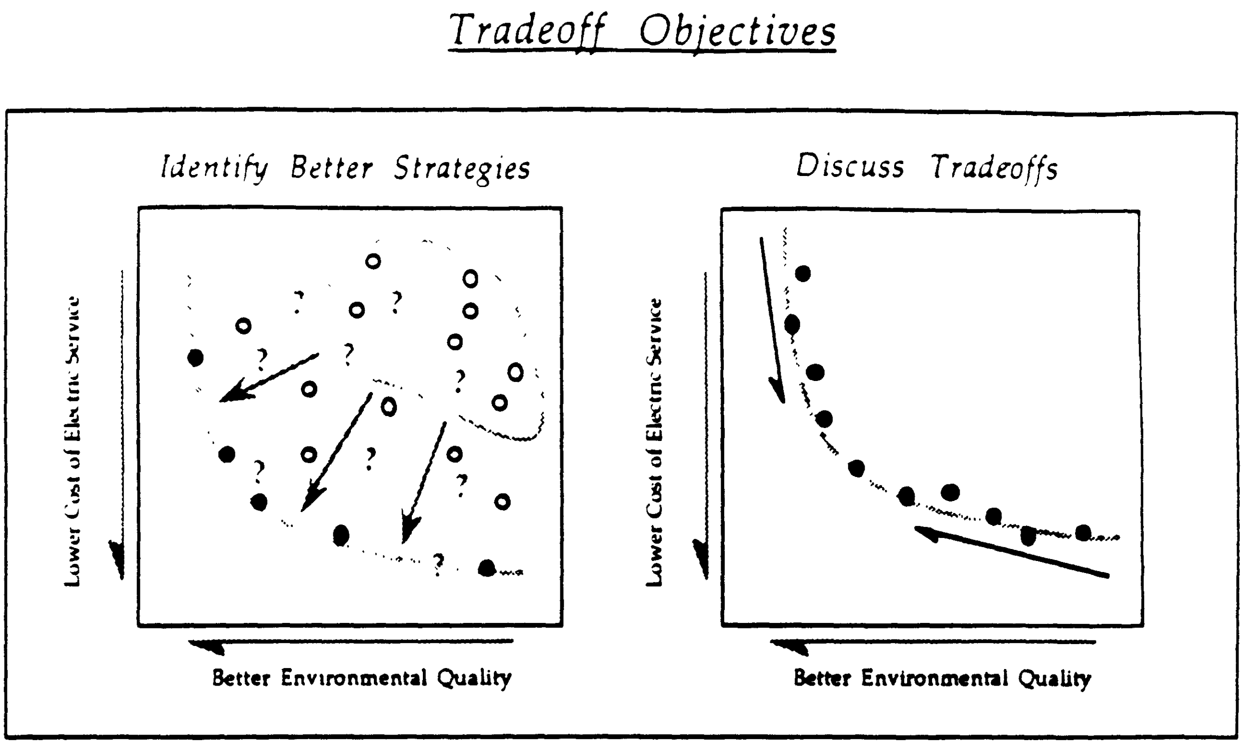
Figure 2.6 - Robustness



Robustness is closely related to the questions of how probable different futures are, and to how risk averse stakeholders are to bad results. In the current analysis, both these issues have been set aside. Futures were initially assumed to be equally likely in the evaluation of average results. For tradeoff analysis, performance was examined for the range of futures by looking at three different futures. The best and worst futures were those that consistently had the lowest and highest cost, emissions, reliability, etc.. A questionaire was used to determine advisory group preferences for the future of highest interest, or greatest concern (hereafter called the "highest-interest" future).

In analyzing tradeoff curves, the analysis team and the advisory group have two different goals, as shown in Figure 2.7. The analysis team has the responsibility to create appropriate scenarios and identify the resulting tradeoffs to the advisory groups. The left hand graph shows this identification of strategies comprising the decision set. The advisory group then has the responsibility to add normative decisions regarding equity and other subjective issues to the facts presented. The right hand graph shows how the advisory group may shift back and forth along the decision set to form a consensus on the strategy which best balances their concerns.

Figure 2.7 - Tradeoff Objectives



Eliciting Participants' Preferences

In order to guide this process of (hopefully) reaching consensus, the analysis team guides the advisory group by presenting the trends and tradeoffs, and then eliciting their preferences. This process is guided by the steps outlined below. While only the advisory group can bring their own, varying positions to this task, it is helpful if the analysis team fully understands the dominant strategies and how robust they are, in order to inform and guide the discussion.

a) Sort through the strategies - slowly adding decision guiding rules.
   i. Which strategies are dominated by others across all attributes and futures?
   ii. Assuming no risk aversion and equally likely futures, how do participants rank the strategies, based on their tradeoffs?
   iii. Assigning different weights to different attributes, how does the ranking change?
   iv. Assigning different probabilities to different futures, how does the ranking change?

v. Adding the assumption of risk-aversion, how does the ranking change?

b) Elicit stakeholder values.
   i. How do different parties prioritize attributes, rank the likelihoods of various futures, view different strategies?

c) Undertake conflict analysis.
   i. What are different parties willing to trade?
   ii. Where are the gaps and overlaps?
   iii. What are the characteristics of the most widely favored strategies?

d) Invent better strategies.
   i. Are there new packages of options that have more of the characteristics everyone prefers?
   ii. What new strategies have the potential for consensus?

   Repeat steps above if necessary.....

e) Seek consensus on a preferred strategy.

This tradeoff analysis approach allows the advisory group members to explore the relative performance of different strategies without initially attaching dollar values to such intangible or hard to quantify - on a cost basis - items as pollution impacts. Unlike cost-benefit analysis, which requires such social costs to be valued in dollar terms, tradeoff analysis keeps attributes in their original units (e.g. tons of SO_2). This allows parties with very different perspectives to evaluate the relative characteristics of the proposed strategies. By the time that parties get down to hard bargaining on the relative importance of electricity costs, environmental impacts, and reliability levels, they will be choosing among a much better group of strategies. These strategies are included in the decision sets by virtue of their physical performance, and not by an implicit or unquantifiable impact/cost calculation. The parties are also more likely, having gone through the analysis as a group, to have a better understanding of the relative importance of each issue in the big, overall picture.

3.0 Developing the Open Planning Process

This chapter takes the group process and analysis theory, and describes how the open planning process was developed through interactions with COM/Elec's *internal* advisory group, prior to use with the *external* consumer advisory groups. This development included finding out COM/Elec's goals and concerns for the open planning process, identifying issues and attributes, and developing scenarios to test the process. The more technical work performed at this stage included collecting and checking data, developing the computer tools, and automating and integrating the computer modeling procedure. Both process development and technical work proceeded concurrently during the project, punctuated by internal advisory group meetings, and came together in the development of graphical presentation techniques to show the scenario results and tradeoffs to the internal advisory group.

3.1 Identifying Issues, Uncertainties and Attributes

The process of developing trial issues, uncertainties and attributes began at the first meeting of the internal advisory group on June 27, 1989. A wide set of issues, attributes, uncertainties and options (divided into utility, consumer, and societal areas) were shown on viewgraphs to facilitate discussion, and then distributed in the form of a questionnaire. This was returned by mail following the meeting, and used as a basis for discussion during the next meeting on July 25, 1989. From the results of the questionnaire, the following overlapping issues and uncertainties were selected as predominant, although not exhaustive;

Predominant Issues

- Cost of Electricity (includes marginal costs, etc.)
- Environmental Air Quality (emissions, regulations, etc.)
- Quality/Reliability of Electricity
- Fuel Availability and Fuel Use Flexibility
- DSM Potential/Impacts (real vs. expected costs, savings, etc.)
- Regulatory Environment (externalities, siting, regulated competition, treatment of investments, etc.)
- Availability/Ability to Use New Technologies (technology advances, lead times, technology regulation, etc.)

Predominant Uncertainties

- Changes in Fuel Prices and Availability
- Changing Environmental Regulations
- Changes in Peak Demand and Energy
- Interactions between DSM Efforts and Third-Party Generation
- Technology Cost and Availability
- DSM Impacts and Implementability

Although the first meeting included a list of sample attributes, the second meeting did not focus on the actual choice of attributes. They were developed during the course of subsequent advisory group presentations and meeting discussions. Examples of such attributes or measures include Average Unit Cost of Electric Service (to measure both the supply-side and demand-side electrical service provided), a rate shock measure (the maximum percentage change in the unit cost of service), and supply, demand, and total system efficiency measures. In all, over 50 attributes were calculated for each scenario (see Appendix B for a complete list of these attributes and the methods of their calculation).

3.2 Developing Scenarios

The issues and uncertainties raised in the first advisory group meetings were translated into analyzable form by defining scenarios. As briefly described in Section 2.2 above, supply and demand options available to COM/Elec are combined into separate option-sets. These option-sets are then combined into strategies. Likewise, uncertainties are combined into futures (each one a possible combination of events), and strategies and futures are combined into Scenarios.

Following the first internal advisory group meeting on June 27, three initial supply-side option-sets were proposed at the July 25 meeting, as shown in Figure 3.1. An initial choice was also made of four demand-side option-sets (No further DSM, the present Collaborative process, an Extended Collaborative process, and the Technical Potential DSM limiting case). The predominant uncertainties were also codified into an initial set of six uncertainties, which are also shown in Figure 3.1.

Figure 3.1 - Initial Strategies and Futures

Strategies

Options are combined into Option Sets which are in turn combined into Strategies.

Supply-Side Option Sets

Technology Options (New Capacity)	Utility Gas Dependent (%-New MW)	NUG Gas Dependent† (%-New MW)	Coal and Cogeneration (%-New MW)
Combustion Turbine 80	40%	20%	—
Combined Cycle 100	60%	30%	20%
Cogeneration 30	—	50%	30%
ICCC 200	—	—	50%

Demand-Side Option Sets / *Combined Strategies* (key)

Demand-Side Option Sets			
Collaborative Programs	CU	CN	CC
Extended Collaborative Programs	EU	EN	EC
Technical Potential	TU	TN	TC
No Further DSM	NU	NN	NC

† Note: NUG = Non-Utility Generation

Futures

Uncertainties are combined into futures

Load Key	Load Growth
L	Low
B	Base
H	High

Fuel Key	Fuel Prices
L	Low
B	Base
H	High

DSM Key	Demand-Side Program Delays
S	On Schedule
D	Program Delay

DSM Key	Demand-Side Program Costs
L	On Budget
H	Cost Overrun

DSM Key	Demand-Side Regulation
C	Capitalize DSM Costs
E	Expense DSM Costs

SS [illegible]y	NUG Dropout Rate
[illegible]	20% of Contracted MW
H	60% of Contracted MW

These initial strategies and futures were revised following the second meeting, and an exchange of correspondence and phone calls. The revised set of options and uncertainties is shown below in Figure 3.2.

Figure 3.2 - Revised Strategies and Futures

Strategies

Options are combined into Option Sets which are in turn combined into Strategies

Supply-Side Option Sets

Technology Options (*New Capacity*)	Gas Dependent (%-New MW)	Coal and Cogeneration (%-New MW)	Repowering (%-New MW)
Combustion Turbine 30	30%	—	50%
Combined Cycle 100	45%	15%	—
Cogeneration 30	25%	25%	50%
ICCC 200	—	35%	—
AFBC 200	—	25%	—
Repower Existing Units	—	—	472 MW

Demand-Side Option Sets	*Combined Strategies*		(key)
Collaborative Programs	CG	CC	CR
Extended Collaborative Programs	EG	EC	ER
Technical Potential	TG	TC	TR
No Further DSM	NG	NC	NR

Futures

Uncertainties are combined into futures

Load Key	*Load Growth*
L	Low
B	Base
H	High

Fuel Key	*Fuel Prices*
L	Low
B	Base
H	High

DSM Key	*Demand-Side Progam Delays*
S	On Schedule
D	Program Delay

SS Key	*Supply-Side Progam Delays*
S	On Schedule
D	Program Delay

DSM Key	*Demand-Side Program Costs*
L	On Budget
H	Cost Overrun

SS Key	*Supply-Side Program Costs*
L	On Budget
H	Cost Overrun

Note: All model runs are done with costs on budget. Cost overruns can be calculated as sensitivity analysis without extra runs.

As can be seen the chief differences are in combining two supply-side option-sets, adding another, and changing the uncertainties. First, the utility and non-utility gas dependent supply-side option-sets were combined, under the assumption that generation ownership questions were less important and more amenable to post-modeling financial analysis. Combustion turbine and combined cycle target ratios were averaged, and cogeneration reduced. The repowering supply-side option-set was added to explore the impacts of adding 472 MW of new and refurbished capacity to three sites otherwise planned to retire. The coal and cogeneration supply-side option-set adds the technological option of atmospheric fluidized bed combustion (AFBC), while reducing the share of coal gasification combined cycle units. This was based on the assumption that catalytic NO_x reduction will increase the cost of coal gasification and make AFBC more competitive. In addition, the assumption was added to all three supply-side option-sets that the life of the Canal plant will be extended indefinitely through the end of the study period (2013).

The range of futures was also modified. The uncertainty for the NUG facility contract rate was dropped, due to COM/Elec's expressed confidence in its contracting procedures. The uncertainty for regulatory treatment of DSM investment was also dropped, since this was felt to be better left to post-modeling financial sensitivity analysis. In response to discussion, two new uncertainties were added to cover the possibilities of schedule and cost overruns for supply-side options, symmetric with those same uncertainties for DSM options.

Multiplying all 12 option-sets by all 144 futures gives a total of 1728 scenarios. Since the two uncertainties for supply-side and DSM cost overruns do not require additional LMSTM runs, the number of computer simulations drops to 432. However, two of the DSM option-sets are not subject to delay (No DSM, and Technical Potential), which reduces the number of total simulations to 324 and total scenarios to 1296.

From this initial set of scenarios, 18 runs were performed to provide preliminary results for the November 20 meeting (1 supply-side option-set, 3 DSM option-sets, 3 load growth, and 2 fuel price uncertainties). Feedback from this meeting confirmed the revised initial set of scenarios, with one addition proposed. It was requested by Mr. B. L. Hunt, Manager of Integrated Planning that an additional uncertainty be added to consider both firm and spot prices for natural gas Rather than double the number of runs, it was proposed to handle this with sensitivity runs on existing scenarios.

By the February 2nd internal advisory group meeting, a total of 108 runs had been performed (4 DSM option-sets - 2 with delays, 3 supply-side option-sets, 3 load growths, and 2 fuel prices) while work on the run automation procedures continued. These results were presented for review on March 2, just before the first external consumer advisory group meeting. The number of scenarios, and the number of simulation model runs required and performed are shown in Figure 3.3, which summarizes the initial and revised test scenarios as well as that of the final scenario set whose development is described in Chapter 4.

Figure 3.3 - Initial, Revised and Final Scenarios

Scenarios Sets Evaluated by the MIT - COM/Elec Analysis Team

Strategies						
Date/Meeting	*25-Jul*	*20-Nov*	*2-Feb*	*23-Apr*	*14-May*	*10-Jul*
Demand-Side Option Sets *	4	4		2		2
Supply-Side Option Sets	3	3		10		8
Reserve Margins				2		2
High/Low Sulfur Oil						2
Total No. of Strategies	12	12		40		64

Futures						
Date/Meeting	*25-Jul*	*20-Nov*	*2-Feb*	*23-Apr*	*14-May*	*10-Jul*
Load/Economic Growth	3	3		3		3
Fuel Prices	2	3		2		2
DSM Option Delay	2	2				
DSM Option Cost Overrun †	2	2				
DSM Regulatory Treatment †	2					
DSM Customer Response				3		3
Supply Option Delay		2				
Supply Option Cost Overrun †		2				
NUG Dropout Rate	2					
Cost of Capital (Interest) †				2		2
Total No. of Futures	96	144		36		36

Scenarios						
Date/Meeting	***25-Jul***	*20-Nov*	*2-Feb*	*23-Apr*	*14-May*	*10-Jul*
Total No. of Scenarios	*864*	*1296*		*1440*		*2304*
Total Runs Required	*216*	*324*		*720*		*1152*
Total Runs Performed		*18*	*108*	*48*	*720*	*1152*

* **Strategies with 4 DSM Options have 2 options which cannot be delayed (No DSM & Technical Potential) so the number of runs and scenarios are reduced by 6/8.**

† **Effects of these uncertainties can be calculated after the simulations are performed, and were done selectively as sensitivity analyses.**

3.3 Collecting and Checking Data

The work of collecting and checking data began when the first scenarios were defined, and continued as they were modified. This painstaking work of forming the model input is the foundation upon which the numerical analysis and the resulting credibility rest. For this reason it is necessary not only to collect the correct data from appropriate sources, but to understand how the data has been based and how it is to be applied. The primary sources for the supply- and demand-side data are discussed below. The data are presented along with their sources in Chapter 5.

Supply-Side Data. The primary source for the supply-side data was the existing LMSTM supply input for COM/Elec's existing and firmly committed units. This data was reviewed, and checked with Mr. Paul Krawczyk and other COM/Elec staff members on the analysis team. During the course of the study this information was updated as new data became available. Such updates included new plant capital cost and O&M escalation rates from Data Resources, Inc. (DRI).

Data for new generating units came from tw major sources. The primary source was the NEPOOL Generation Task Force (GTF) December 1989 report, and the secondary source was the Electric Power Research Institute's (EPRI's) 1989 Technology Assessment Guide. Assumptions for the Repowering and Canal 3 options came from conversations with COM/Elec's engineers and planning staff, as well as EPRI and MIT sources. Cogeneration data came from a COM/Elec cogeneration survey, Office of Technology Assessment technology characterizations, and conversation with the engineer for the firm 25 MW of cogeneration planned at MIT.

Fuel prices were taken from the DRI price forecasts prepared for COM/Elec. As part of the review process, it was judged that the high prices forecast for natural gas and oil were inconsistent relative to each other. Modifications to the high natural gas prices are described in Chapter 5.

Emissions data was linked to the fuel price data, but came from a variety of sources. Average emissions for existing units was taken from the EPA report AP-42, and data for new units was taken from trade journals and sources at EPRI, the Northeast States for Coordinated Air Use Management (NESCAUM), and MIT.

Demand-Side Management Data. The data for the Collaborative and Enhanced Collaborative option-sets was developed through COM/Elec's participation in the Collaborative Process with the Conservation Law Foundation. This participation is reported in the company's Massachusetts State Collaborative Phase II report of October 1989 (or a more recent version), and all data entered into the model came directly from an August 1, 1989 draft of that report. This data for individual DSM programs were extensively reviewed, including data on load profiles, penetration rates, savings, measure costs, general and administrative costs, and seasonal savings distributions. This data was then combined into the various programs making up the DSM option-sets.

Although the Technical Potential option-set, developed as a limiting test case during the development process, was not used in the scenarios analyzed for the external consumer advisory groups, it was also a carefully developed and reviewed option-set representing the maximum amount of DSM technically available in the COM/Elec service territory. This option-set was based on work by Mr. John Farley of COM/Elec, an assessment of

COM/Elec's technical potential by Xenergy, Inc, and work with Mr. Mort Zajac of COM/Elec. Over 90 DSM measures were applied to 11 different building types and aggregated into DSM programs. These programs included some assumptions developed for the collaborative programs, including use factors and load shapes.

The data for these option-sets were used to modify COM/Elec's own load forecast which already included estimates of DSM savings due to general market forces.

3.4 Modeling Procedure and Software Tools

Once scenarios have been defined and data collected, the input files are assembled, and computer simulations are run. Attributes are calculated from both the input and output data. This section covers the technical flow of the computer modeling process, and describes the computer programs and tools developed to automate the file construction, model run, and analysis processes. This process is illustrated in Figure 3.4, which has been divided into two pages for the sake of clarity.

Figure 3.4a - The Modeling Process

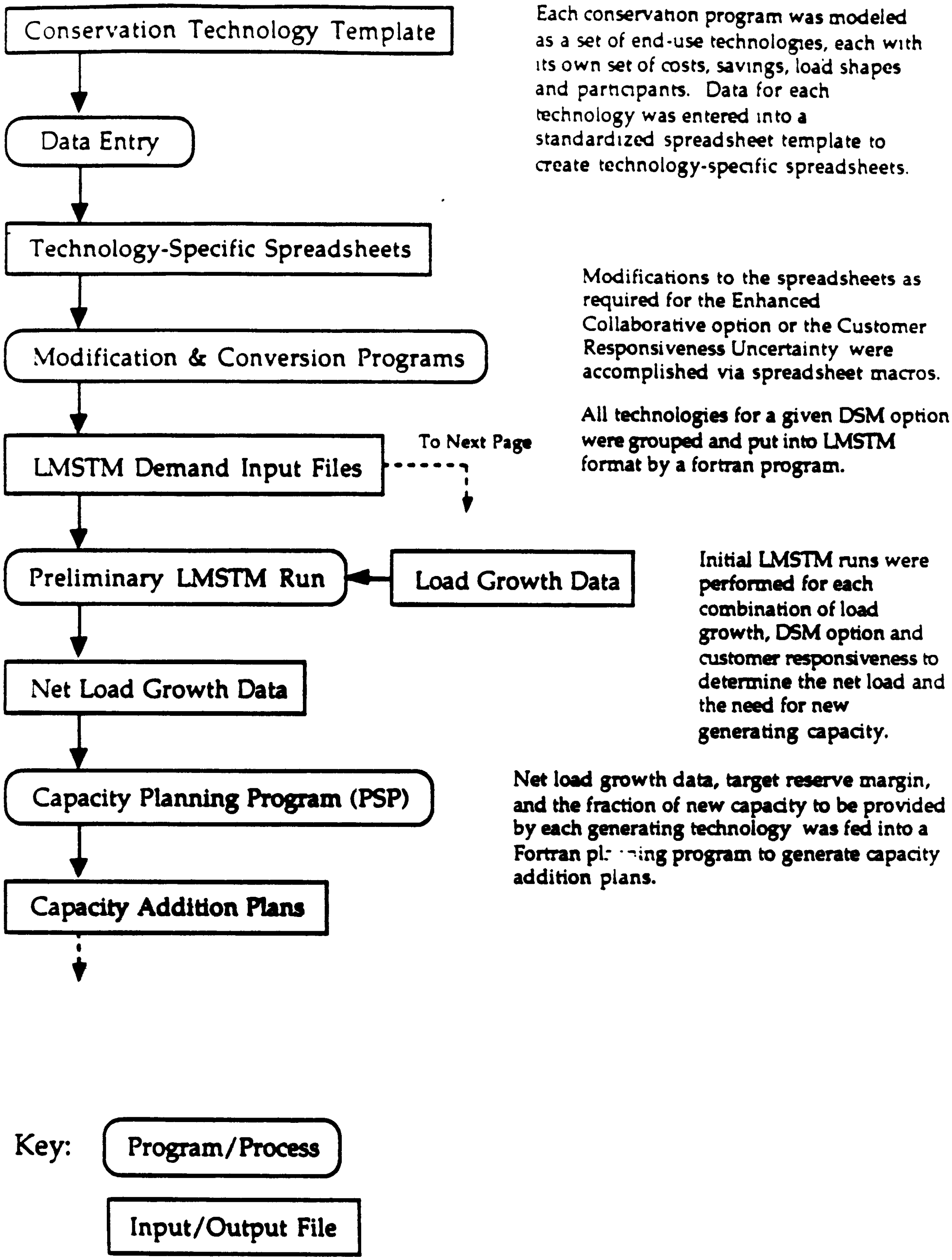
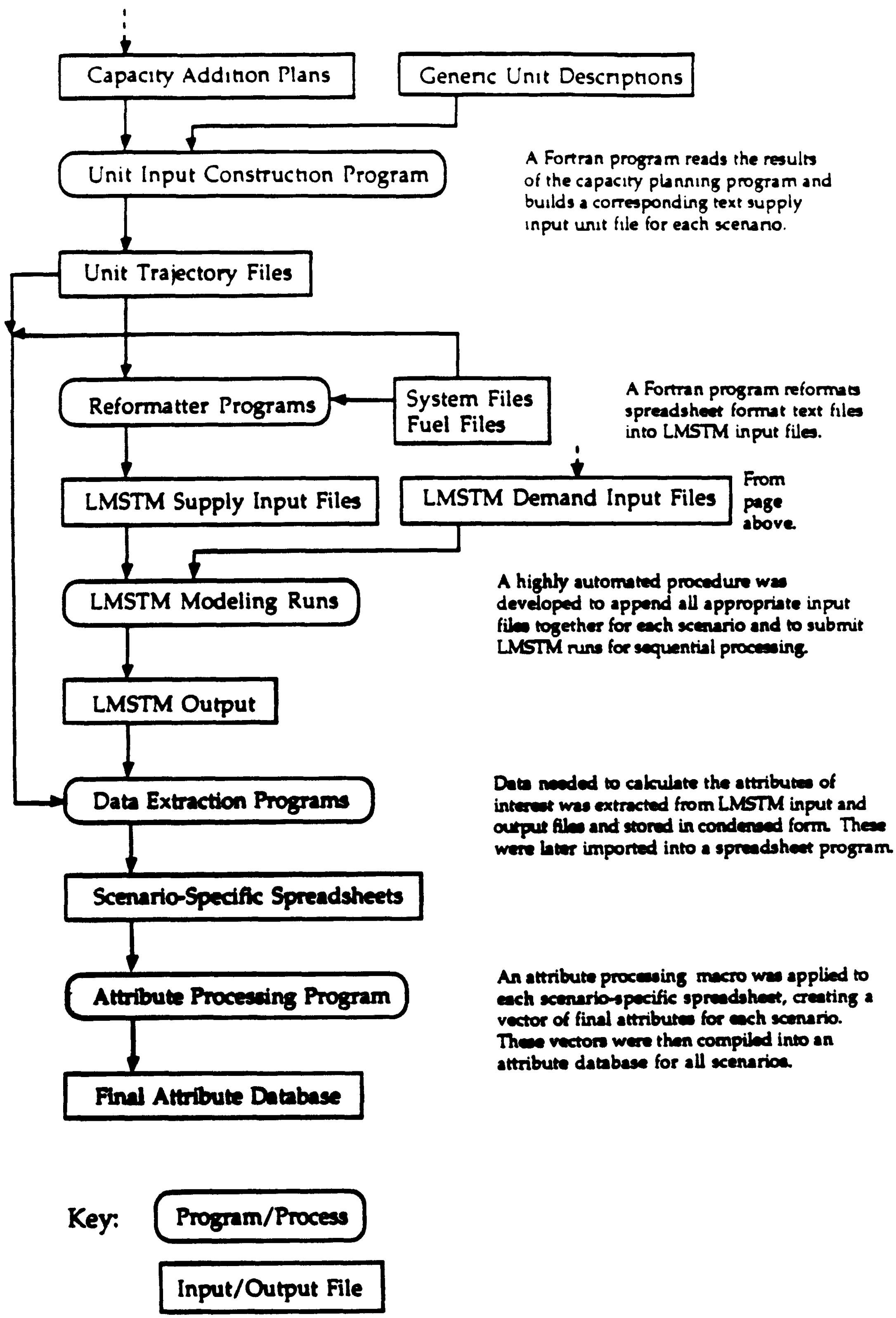


Figure 3.4b - The Modeling Process (Continued)



The mechanics of this process are laid out step-by-step and discussed in the run book presented to COM/Elec during a tutorial session in June. This discussion will expand upon Figure 3.4 by presenting the software programs developed and tying them to the process sequence.

Demand Side Management Modification and Conversion Programs

The process of constructing the demand-side LMSTM input files began with a 2020 spreadsheet template, into which information about each conservation technology was entered. All information for the base-case DSM option, the Collaborative Process Programs, came directly out of August 1, 1989 Phase II report on that effort. As conservation programs were modeled on an end-use basis, each program had several conservation technologies, and thus several 2020 spreadsheets to describe each of them. With these 2020 spreadsheets constructed, simple 2020 macros were written to perform the modifications necessary to model the Enhanced Collaborative option-set and the Customer Responsiveness uncertainty. To automate this modification process, a VMS command file called SUPERMAC was written. SUPERMAC accepts a list of the conservation technology spreadsheets to be processed, and runs a Fortran program called MACRITE. MACRITE, in turn, writes a long 2020 macro based on the file list and one of the task-specific macros mentioned above. When MACRITE has finished, SUPERMAC regains control and tells the VAX to run the long 2020 macro that was just written. The resulting files are appropriately modified DSM technology-specific spreadsheets.

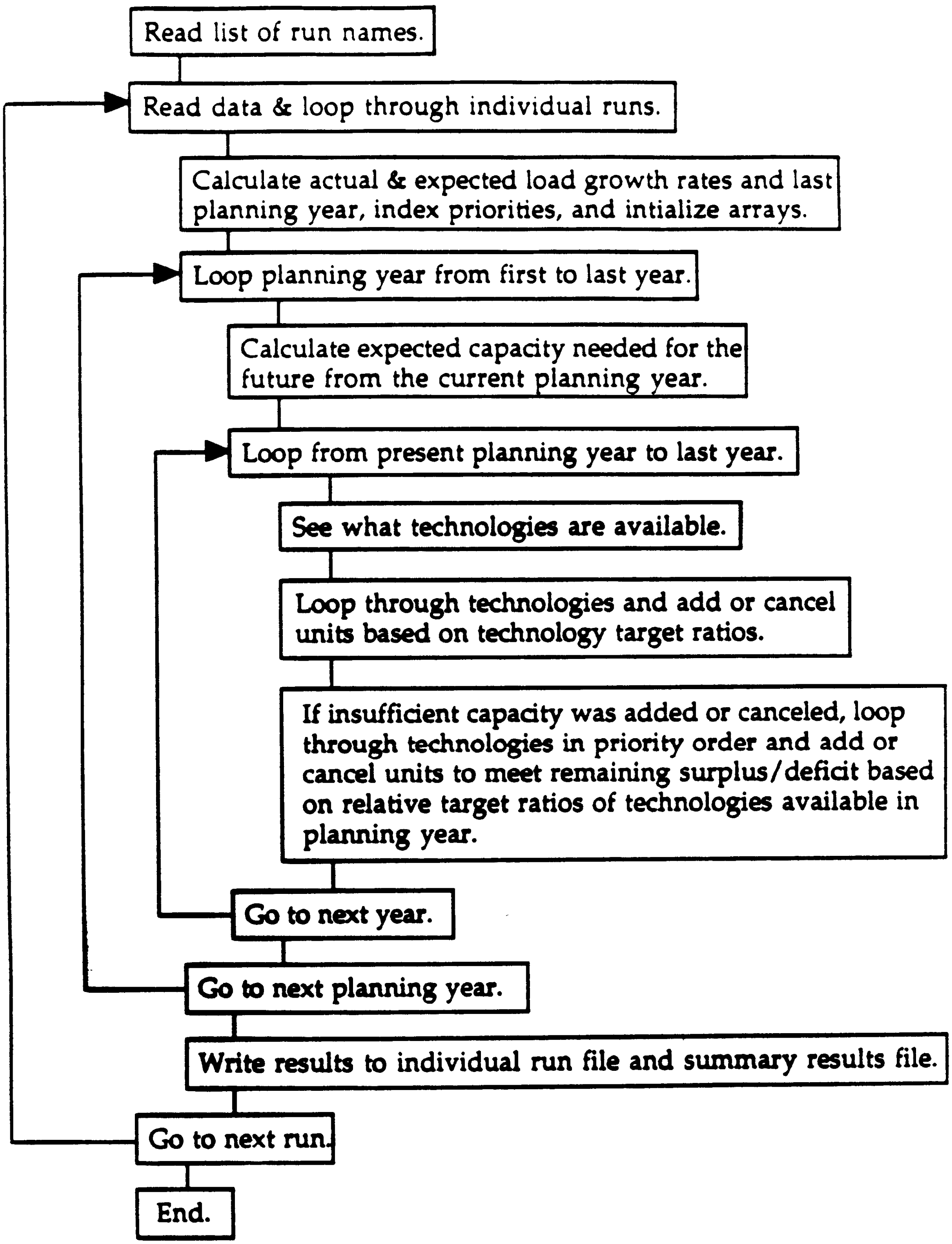
The 2020 template was used for data entry because of its flexibility and its familiarity to COM/Elec personnel. Before it could be used however, the data in each of the spreadsheets had to be converted into the specific format required by LMSTM. This was accomplished in two steps. First, a process very similar to that described above was used to export data in the spreadsheets into a text format. For this a command file called EXPORT was used. EXPORT accepts a list of spreadsheet names and calls EXPORT.FOR, a Fortran program which writes a 2020 macro based on the list of spreadsheets. That macro successively reads each spreadsheet into 2020 and calls a very brief macro which has the task of exporting the data in each successive spreadsheet. With the data for each DSM technology now in text format, a Fortran reformatting program called DEMAND-CDF.for was used to compile the technologies into blocks C, D, and F of the LMSTM demand input file. The remaining blocks, which are invariant from scenario to scenario, are appended to blocks C, D, and F just before each scenario is run.

The Prespecified Pathway Program

Most of the programs developed to perform or automate scenario analysis are straightforward and do relatively simple jobs without any hidden assumptions. However the Prespecified Pathway (PSP) program which does the capacity planning for each scenario contains an algorithm which should be understood by the user in order to have confidence in the simulation results. This section therefore presents the PSP program and how it operates at a more detailed level than the rest of this section.

Planning the number and on-line dates of new units in the prescribed ratio required to meet projected loads plus a reserve margin would require a prohibitive effort if done individually "by hand" for each scenario. For this reason, the PSP program was developed. It emulates the process of planning new capacity, committing and cancelling new units in the correct amounts. The PSP algorithm is shown in Figure 3.5 and further discussed below.

Figure 3.5 - PSP Algorithm Flowchart



For each PSP run, the program first reads the actual historical loads for the near past and the expected peak loads, based on load growth and adjusted for the demand-side option-set and related uncertainties. The program then reads the expected trajectory of existing and committed new capacity, and the new capacity technical characteristics and target ratios.

In the first planning year, PSP finds the average growth rate for the previous three years, and projects load growth at this constant rate over the remainder of the study period. It then plans capacity to meet this projected demand. When this is done, PSP advances to the next planning year, moves the three year running average forward one year, and recalculates the expected demand based on this revised growth rate. PSP plans to meet this revised demand plus a reserve margin, committing or cancelling additional units as required. In this way, the PSP emulates the way utility planning is influenced by the recent past, and preserves the effects of random, unexpected changes in load growth. If load grows unexpectedly, only units with low lead times can be built to meet demand, and if load drops only those units which have not progressed too far can be cancelled.

Utility load forecasts tend to be much smoother than actual demand, especially further out in the forecast period. In order to model the effect of unsteady growth, the load forecast can be randomized by varying it around the projected trend. However, the analysis team judged that the COM/Elec load forecast already varied sufficiently so that this step was not necessary. If the analysis team has overriding expectations regarding load growth, the 3 year running average can be bounded by minimum and maximum limits. This was done for the final set of 1152 runs to limit the impact of the 18.4% historical growth between 1986 and 1987.

As the PSP plans supply-side resources from the current planning year forward, the commitment and cancelling of plants takes place in two stages as follows:

<u>Cumulative Ratioing</u> - Future units are added or cancelled from the pathway to attain the cumulative new MW target ratios for each technology as read from the input file.

<u>Annual Ratioing</u> - If cumulative ratioing cannot commit or cancel sufficient capacity, then technologies are added or cancelled in any one year based on their relative ratios with other technologies available in that year. For example, if the only technologies available in a given year are combustion turbines (target ratio 25%) and combined cycle units (target ratio 25%), the PSP will attempt to build or cancel 50% of the required MW using each technology. Commitment or cancellation priorities can be specified to determine the order in which each technology is considered under this procedure.

To simulate limited gas availability, the PSP allows an upper limit to be placed on gas-fired capacity that may be added in each year. The limited availability of new technologies can also be simulated by specifying a cumulative limit for each technology in each year.

Once the PSP planning process is complete, the program writes a file that gives the number of units committed and the reserve margins for each year. A line is also written to a summary output file which records the total number of units built and reserve margin data for the entire planning period.

Unit Trajectory Construction Program

As shown in Figure 3.4, a program is required to assemble the unit description input file based on the PSP capacity trajectories determined. A Fortran program called BUILD-GEN was written that reads the PSP unit trajectory, and repeatedly copies generic unit descriptions to an output file, inserting appropriate names and on-line years for each new unit. Unit descriptions, and so the unit trajectory files, are in the form of spreadsheet output text files, which must next be converted to LMSTM input files.

Reformatting Programs

In addition to the new unit trajectory data, the reformatting programs must also combine the correct group definitions, system data, fuel prices, emissions data, existing and fixed-size unit descriptions, and OP-4 reliability unit descriptions. Four Fortran programs were written to perform these conversions to LMSTM format (SUPPLY-MISC, SUPPLY-GD, SUPPLY-BF, and SUPPLY-UNITS). A Fortran program was also written (COM-WRITE) that reads each scenario name, parses it to choose the correct input files, and writes a VMS command file (a com file) that automatically runs the four reformatter programs, appends their outputs into a single LMSTM input file, and deletes all intermedi e files.

LMSTM Automation Programs

In order to automate the process of running the LMSTM model, a Fortran program was written called COMRIT. This program reads a list of run names and writes a VMS editor (EDT) command file. This EDT com file repeatedly edits a VMS com file template, and writes a series of VMS com files. These com files give LMSTM the correct input and output files, run the LMSTM model, run a Fortran program to read the output data, and then submit the next LMSTM run.

Data Extraction and Reduction Programs

Once the LMSTM model runs have been performed, it is necessary to extract the necessary data from the input and output files, and reduce it for attribute calculations. The Fortran program FILEPROC takes the group, fuel, and unit input files, processes these files and condenses the attributes into a single output file. In order to run this program repeatedly, a Fortran program called RUN-BATCH was also written to read a list of LMSTM run names and write the appropriate com file to run the file processor. Due to the time required for FILEPROC to read all the input data, a second program was written (FILEPROC2). This variation processes related groups of runs to reduce the redundancy to reading some files over and over.

Data from several output files created by LMSTM during each run are extracted by a Fortran program called READER.FOR. This program does no attribute processing, but simply locates and reads pertinent data, then stores it in a condensed data file which is in a convenient form for importation by 2020.

Attribute Processing Program

The calculation of most of the final attributes for each scenario is performed in 2020. As with input preparation and run processing, attribute processing is highly automated. A command file called GRINDER accepts a filename list telling it which LMSTM runs to process. It then runs a Fortran program which writes two 2020 macros called GRINDER.C20 and DBASE.C20. GRINDER.C20 first imports the condensed output data file for a given run (i.e. the file created by READER.FOR) into 2020, and then calls a macro named NEWCHUG.C20. NEWCHUG is the real workhorse of the process, first locating and appending the corresponding FILEPROC data (which is condensed data from the LMSTM input files), and next performing a series of calculations based on the imported data. Once the attributes have been calculated, they are compiled into an "attribute vector" at the bottom of the spreadsheet. Each LMSTM run is processed in turn, and a large spreadsheet containing all pertinent data and attributes is saved for each run. When the last run has been processed, control briefly transfers back to GRINDER, which then calls DBASE.C20. The task of DBASE.C20 is simply to collect the attribute vectors from each spreadsheet and place them into a single attribute database. The final step prior to statistical analysis of the data was to convert the database into the text format suitable for use by standard statistical packages.

3.5 Statistical Analysis Techniques

Once the computer modeling runs have been completed, it is necessary to interpret the mass of results. The theoretical questions that guide this interpretation have been covered in Chapter 2. During this part of the open planning development process methods were created to answer these questions using a variety of statistical tools.

The first issue for the statistical analysis was the choice of a software package, and whether it should be mainframe or microcomputer based. The two primary considerations are the ability to handle a sufficiently large database, and ability to produce the desired results and graphics on flexible subsets of the data. The analysis team chose to use Systat™ on microcomputers. An important secondary consideration is that the software should have the capability of reading or recording macros so that related groups of graphs can be easily produced (e.g. all attributes vs. all uncertainties). Graphs should also be easily imported into a graphics package for easy conversion into presentation quality plots.

Once a statistics package was chosen, graphs were produced for an exhaustive set of data relationships. The graphs produced were boxplots and tradeoff scatterplots (both described in Chapter 2). Because statistical packages (like Systat™) will not parse the unique scenario name given in each row of the database, it was necessary to create other columns in the database which contained labels indicating supply-side option-set, future, etc. using subsets of the scenario name. Using these labels it was possible to group the results as required. In some cases it was also necessary to create subsets of the master database for analysis (e.g. to analyze three futures - best, worst, and highest-interest - out of all eighteen).

Throughout the process of both single and multiple attribute graphical analysis, it is important to keep asking, "Does this result make sense?", because it is at this point that errors in the analysis process first become readily apparent - if you are looking for them. Errors in unit conversions, confusion of input files (e.g. a low versus a high sulfur oil run), etc., can all become evident when the pattern of results is inconsistent. Counter-intuitive results can lead to real and important insights, but they must be the result of an understandable underlying story, rather than an overlooked error.

3.6 Presentation and Elicitation Techniques

After developing, modeling, and analyzing scenarios it is necessary to present the results to the advisory group and elicit their responses. As part of the open planning development process with COM/Elec's internal advisory group these presentation and elicitation techniques were also developed. During the series of advisory group meetings different results were presented in different graphical formats to judge whether the correct balance was struck between information density and clarity of presentation. In particular, after the boxplots used by the analysis team were presented to the COM/Elec internal advisory group, it was judged that these would be too complex for presentation to a less utility-sophisticated external consumer advisory group. Instead column charts and arrow charts were developed to simplify presentation (arrow charts simply use up or down arrows to identify linked or countervailing trends in a non-quantitative way). These presentation methods are used to discuss results in both Chapters 4 and 6.

4.0 Applying the Open Planning Process

This chapter describes the formation of the external consumer advisory groups, the conduct of the meetings, and the interactions, feedback, and conclusions obtained. It also discusses in some detail how the issues and uncertainties concerning these groups were developed into the final set of scenarios, modeled, and how these scenarios differed from the initial set of scenarios developed with the COM/Elec internal advisory group. This final set of scenarios is described in detail in Chapter 5.

4.1 Organizing the Advisory Groups

On November 7th, 1989, COM/Electric, MIT, and the public relations firm of Moore and Isherwood met to organize the logistics of forming the external advisory groups. For this initial experiment, it was decided that there should be four advisory groups, one for each of the company's service districts: Cambridge, Plymouth, New Bedford, and Cape Cod. Each group would have three meetings, about two hours in length, about three weeks apart, facilitated by a member of the MIT team. The goal was to have about a dozen regular participants in each advisory group. The public relations firm began developing letters of invitation, while COM/Electric's district service representatives identified a "cross section of leading citizens" who should participate.

The next internal advisory group meeting was on November 20th, 1989. The focus of that meeting was on an initial set of results: eighteen scenarios exploring one supply-side option-set, three demand-side option-sets, three load growth uncertainty values, and two fuel price uncertainty values. The meeting had two goals, first, to check the credibility of the results with the COM/Elec internal advisory group, and second, to discuss techniques for communicating technical information to non-technical audiences.

Following minor technical comments by COM/Electric personnel, the public relations experts made suggestions about ways to get MIT's technical message across to a lay audience. They stressed that the meetings must be enjoyable to the participants, and recommended using a pre-packaged video or slide show so that interruptions would not dilute the presentation's desired impact. They warned that the audience was likely to be intimidated by the MIT speaker, and that the initial presentation should therefore use non-technical language, and be as accessible as possible.

The detailed objectives of the three external advisory group sessions were spelled out in a meeting with the vice president in charge of the project at COM/Electric on January 5th, 1990. These objectives are listed in Table 4.1.

Table 4.1 - Objectives

SESSION 1
- Introductions
- Describe Open Planning Concept
- Explain COM/Electric's Desires for Open Planning
- Outline Known Issues of Importance
- Discuss Base Resource Plan and Alternatives
- Identify Major Uncertainties
- Elicit Consumer Issues and Concerns
- Outline Work to be done for Session 2

SESSION 2
- Present Composite Results of Outlined Work
- Identify Tradeoffs
- Revisit Issues and Concerns
- Outline Additional Work for Session 3 to Develop Composite Plan

SESSION 3
- Present Composite Plan
- Seek Areas of Consensus
- Evaluate Project

The initial sessions were prefaced by a mailing providing the overall agenda, a note on the goals of open planning, and newspaper clippings on recent electric power issues involving COM/Elec. It was agreed to develop a slide show for the first meetings to cover basic background information on COM/Electric, the concepts and vocabulary of the open planning process, and examples of the types of tradeoffs to be confronted in subsequent meetings. The remainder of the first meetings would be interactive, with a facilitator eliciting issues, uncertainties, and possible options from the advisory group members, followed by a prioritization of the issues. The remaining meetings would rely on viewgraphs instead of slides to convey information because a quicker turn-around time was required.

From a planning perspective, the points that COM/Electric hoped to get across in the external advisory group sessions included: (1) the company's desire to open up its planning process; (2) the company's obligation to serve all of customers' loads; (3) the characteristics of the available options; (4) the existence of multiple decision criteria: economics, environment, level of service, etc.; (5) the need for the company to make tradeoffs among criteria when choosing options; and (6) the company's desire to incorporate the customers' preferences regarding tradeoffs.

Related factors looming on COM/Electric's horizon included a new resource plan to be filed with the Energy Facilities Siting Council and the Department of Public Utilities, the need to develop a sound environmental externality evaluation approach, and the impending switch to all resource bidding for new increments of capacity.

On February 2nd, 1990, MIT presented a dry run of the slide show to the COM/Electric internal advisory group, based on the results of the 108 scenarios calculated to date. These were then turned into finished slides. A month later MIT presented a detailed technical exposition of these results to the internal advisory group; giving them their last chance to catch technical errors. The following week the first external advisory group sessions began.

The citizens that COM/Electric invited to the meetings came from a variety of backgrounds (see participants' list in Appendix A). Their letters of invitation included the overview of the open planning project as shown in Figure 4.1.

Figure 4.1 - Overview of the COM/Electric Open Planning Project

COM/Electric, in conjunction with the MIT Energy Lab, has embarked on a program designed to make our customers aware of the complexities faced by an electric utility operating in an era of conflict and uncertainty; and to invite a cross-section of these customers to participate in the planning process.

What we propose to do is solicit the input of people that we have identified as "decision makers." That is people who through their involvement in the community they live or work in, have the support and confidence of that community.

These people represent the business community, the political spectrum, environmental groups and community advocates.

Our goal and that of the MIT Energy Lab, is to explain in non-technical language, the planning process in an environment that is growing increasingly uncertain.

What we hope to accomplish is what all of us recognize; that there are no simple solutions to meeting our energy needs and that certain tradeoffs have to be considered as part of the planning process. Tradeoff is a word that will be emphasized and repeated throughout these meetings.

The participants who will make up our Advisory Group will be provided with the information required to make rational decisions regarding future energy needs.

Discussion will focus on costs, reliability, environmental issues and technological advancements. These are just some of the issues that will be addressed as we try to develop a strategy for the next decade and beyond.

Will we be in total agreement? Probably not. But total agreement is not necessarily what we hope to achieve.

In all probability our greatest success will come from the fact that we as a company have taken the lead in providing our customers with the information which will enable them to make intelligent and informed decisions. These decisions will truly reflect their concerns and choices about our future needs and how we as a utility hope to achieve our goal of providing a reliable and economical supply of electricity.

The success of the Advisory Group is a critical first step in making the customers we serve aware of the commitment of COM/Electric to resource planning and development.

4.2 First Meetings: Introduction, Prioritizing Issues, and Brainstorming for Options

Although the schedule, presentation, and meeting organization were similar for the four advisory groups, each of them quickly evolved in a unique direction.

This could be seen in the attendance, issues raised, pattern of discussion, and final outcome. The population of the COM/Electric service territory was clearly not homogeneous, even for the small and non-random sample participating in this experiment.

In Cambridge, eight of the ten citizens who had accepted invitations attended the first meeting on March 5th, 1990. These included a state representative, and spokespeople for the City of Cambridge, neighborhood associations, major industries and institutions, the Chamber of Commerce, and anti-development interests. All of the attendees were active in the discussion, but three were especially vocal. Out of a total of 36 comments made, they made seven or more comments each, compared to a group average of 4.5. These three represented Polaroid, the City of Cambridge, and the Hastings Square Neighborhood Association. The highest priority issue for the group was environmental impacts, with electricity cost and reliability tied for second place. Participants were asked to identify their most important issues, based on a show of hands in which each participant was allowed two votes. See Tables 4.3, 4.4, and 4.5 for a complete list of issues, uncertainties, and options generated at these meetings.

The Plymouth meeting, held on March 6th, 1990, the evening of the year's worst snowstorm, had low attendance, with only four attending out of the eleven who had accepted invitations. These four included the state representative, a representative of the Board of Selectmen, president of the local newspaper chain, and president of a local bank. Again, all of the attendees were active in the discussion, although one person (from the Board of Selectmen) was particularly vocal. This person provided ten of the 27 comments, compared to a group average of 6.75. Reliability was the only issue that garnered more than a single vote (out of 2x4=8 possible). Environment, cost, energy education, and the value of commercial demand-side management subsidies each received one vote.

New Bedford enjoyed a higher turnout than expected at its meeting on March 8th, 1990. Although only six people had accepted invitations, ten showed up. These included representatives of the mayor's office, other nearby municipal governments, local industry, local newspapers and television, the United Way, a county development council, and a cranberry grower. Participation in the discussion was much more uneven, with individuals contributing from zero to seven comments each, for a total of 31 comments. The most vocal person was the president of a local industry (whose electricity costs had recently increased), all of whose comments were about different aspects of electricity cost: its average level, volatility, rate structures, the resulting competitive position of the region, and the corporate productivity or operating efficiency of COM/Electric. Not surprisingly, the highest priority issue in the voting was electricity cost, followed by environmental impacts. The credibility and operating efficiency of the utility tied for a distant third place.

The first meeting in Cape Cod was on March 14th, 1990. Seven of the ten people who had accepted invitations showed up. They included a state senator and his aide, and representatives of the regional planning and development commission, a hospital, a bank, a retail chain, and the Chamber of Commerce. This group enjoyed the most active discussion among the four initial sessions, making 51 comments, an average of 7.3 per person. Three participants were especially vocal: the retailer made fifteen comments, many revolving around adequacy of supply; the state senator made eleven, covering a range of company credibility, public health, and policy issues; and the planning commission staffer made nine, focusing on environmental impacts and innovative technical options. The group had a thorough discussion of the various levels of environmental impacts – local, regional, and global – and their different types – æsthetic impacts on sites, emissions, waste disposal, electromagnetic fields, land and water use – as well as expressing concern for the uncertainties, such as threshold effects, associated with many impacts. In voting, they ranked environmental issues as their highest priority, with reliability and Company communications efforts equally sharing the remaining votes. Unlike the other groups, cost issues received no votes on the Cape.

All of the meetings were organized in a similar manner, beginning with a slide show (see Table 4.2 for the script). The slides served to introduce the participants to the project, COM/Electric, and the open planning process. It also discussed the desired results, and provided examples of options, impacts, and uncertainties. It closed with a request for input from the group. Using a blackboard, the facilitator led the group in identifying electric power-related issues of concern to them, followed by uncertainties that affected these issues, and finally options that COM/Electric could bring to bear over the next twenty five years to address the issues. After the brainstorming session, the facilitator went back and asked the group to prioritize the issues by voting for their favorites. Uncertainties and options were not prioritized.

Table 4.2 - Slideshow Script for First COM/Electric Advisory Group Meetings

Segment	Slide No.	Title/Contents	Point/Bridge
Intro to Project and Participants	1	The Open Planning Process/Boardroom	
	2	COM/Elec—MIT Logos	MIT Analysis-COM/Elec Initiative
	3	COM/Elec Service Territories & Companies	Dealing w/ Complex Systems
Intro to Open Planning Process	4	The Open Planning Process/Plain	Need to Address the Complexity
	5	Components-Issues	
	6	Components-Uncertainties	
	7	Components-Options	
	8	Components-All Together	
	9	Issues	Goals/Concerns
	10	Issues-Cost of Electricity	
	11	Issues-Environmental Impacts	
	12	Issues-Reliability, etc.	
	13	Uncertainties	Constraints/Concerns
	14	Uncertainties-Fuel Prices	
	15	Uncertainties-Load Growth	
	16	Uncertainties-many others...	
	17	Options	
	18	Options-DSM	
	19	Options-Supply-Side	
	20	Options-Both/Strategies	How to Implement?
	21	Analysis Process	Many, Many Scenarios
	22	Issues-All	How to Measure?
	23	Cost of Electricity-Measures	
	24	Environmental Impacts-Measures	
	25	Reliability-Measures	
Results from Such a Process	26	What are the Trade-Offs?/Boardroom	What kind of results do we get?
	27	Three Sample Classes-Cost/Environ./Uncer.	Need to review set of Options
What are the options?	28	DSM Programs	Lots of other options viewed...
	29	Current Programs	Actual
	30	Additional Programs	Feasible
	31	No Programs	Comparative
	32	Theoretical Maximum	Hypothetical/Comparative
	33	Three Sample Classes-Encore	
Cost Impacts	34	Cost Impacts	
	35	DSM Investment Up/Total Costs Down	
	36	Unit Costs Up/Total Use Down	
	37	Monthly Bill Down	...but only if you Conserve
Environmental Impacts	38	Environmental Impacts	
	39	Fewer Plant Sites-Bullet	
	40	Fewer Plant Sites-Graph	
	41	Mixed Emissions-Bullet	
	42	CO2 Down-Bullet	
	43	SO2 Can Increase Bullet	
	44	CO2 & SO2 Graph	DSM doesn't pollute...
	45	Why Don't Emissions Decrease-Graphic	but deters Supply-Side efficiency
	46	CO2 & SO2 Graph	DSM doesn't pollute...
Effects of Uncertainties	47	Effects of Uncertainties	Driven by Fuel Price Forecast
	48	Load Growth-Incr. Nat.Gas/Efficiency/Env.Q	and Relative Fuel Prices
Planning for the Future	49	Planning for the Future	
	50	Requires your input	
	51	Prioritize Issues/Concerns	
	52	Develop Strategies	
	53	End-Issues/Uncertainites/Options ???	Open up discussions...

After the initial round of advisory group meetings was finished, the analysis team aggregated the results to guide them in preparing for the next meetings. Issues and uncertainties were divided into those that could be analyzed in detail, and others for which the team could only summarize existing research. Across all meetings, many of the same issues surfaced without prompting from the facilitator, but they were often accorded different priorities. As Table 4.3 shows, issues that were highly-ranked in most of the groups included environmental impacts, electricity costs, and reliability of supply. These formed the basis for the analytic work. For other issues, such as regional competitiveness and the health effects of electromagnetic fields (EMF), an information package containing short summaries and excerpts of articles was prepared. The high priority issues guided the choice of options to be modeled, and the attributes to measure those options' outcomes.

Many of the same uncertainties surfaced in each of the four meetings (see Table 4.4). Based on the aggregated input from the groups, the analysis team modeled the following uncertainties in detail: economic and electricity load growth, fuel prices and availability, and customer response to utility conservation measures. Likewise, a limited set of options were repeatedly suggested (see Table 4.5).

The analysis team combined the issues and uncertainties into modeling scenarios, incorporating the options suggested into the strategies formed. Using the integrated modeling setup that had been developed over the previous year, and the information on options and uncertainties that had been explored to date, the analysis team was able to quickly model new strategies reflecting the aggregate interests and concerns of the four advisory groups. During the one month between the first and second sets of meetings, the group defined the new scenario set, acquired data needed for accurate modeling, and ran the first 48 scenarios.

Table 4.3 - Issues

Results of Discussions with COM/Elec Consumer Advisory Groups during March 5 - 14, 1990.

Action	TOTAL Issue	Rank Sum	CAMBRIDGE Issue	Rank	Votes	PLYMOUTH Issue	Rank	Votes	NEW BEDFORD Issue	Rank	Votes	CAPE COD Issue	Rank	Votes
Analyze	Environment	6	Environment	1	5	Environment	2	1	Environment Atmospheric Emissions Siting of Cogenerators	2	7	Environment Atmospheric Emissions Visual Impacts Nuclear Waste Disposal	1	6
Analyze	Cost	8	Cost Predictability of Costs Welfare/Lifeline Rate Cross-subsidies Equity Impacts of DSM	2	3	Cost	2	1	Cost Utility as Social Welfare Organization	1	9	Cost	3	0
Analyze	Reliability	9	Reliability Long-term Adequacy of Supply Viability	2	3	Reliability	1	2	Reliability	4	0	Reliability Adequacy of Supply	2	4
Summarize	Communications	11	Communications	4		Communications Education	2	1	Communications Credibility of Utility	3	2	Communications Accountability Image/Credibility Gov't Energy Policy	2	4
Summarize	Regional Competitiveness	13	Regional Competitiveness Jobs	3	1	Regional Competitiveness	3	0	Regional Competitiveness Jobs	4	0	Regional Competitiveness	3	0
Summarize	EMF/Transmission	14	EMF/Transmission	4		EMF/Transmission Transmissions & Distribution	3	0	EMF/Transmission	4	0	EMF/Transmission Technology Related Mystery EMF/T&D	3	0
Move to Uncertainty or Option list			Other Local Capacity Implications of Large Comm. Project Security of supply	 3 3	 1 1	Other HVAC Subsidies & Building Codes	 2	 1	Other Increased Efficiency of Supply/Operation	 3	 2	Other		

4 - 11

Table 4.4 - Uncertainties

Results of discussions with COM/Electric

Consumer Advisory Groups during March 5 - 14, 1990.

Action	COMBINED	CAMBRIDGE	PLYMOUTH	NEW BEDFORD	CAPE COD
Analyze	Fuel Price	Fuel Price	Fuel Price	Fuel Price	Fuel Price
Analyze	Fuel availability	Fuel availability	Fuel availability esp. of foreign supply and gas	Fuel availability Availability of alternative resources	Fuel availability
Analyze	Technological developments (timing, availability, performance, costs)	Technological developments	Technological developments Adequacy of R&D	Tech. availability Adequacy of R&D	Technological developments new techs
Analyze or Summarize	Regulation	Regulation Legislation Gov't funding of tax credits incentives, etc.	Regulation	Regulatory behavior r.e. supply options (R&D) (Siting) (Rates) Restructure industry Competition in supply Deregulate wheeling	Regulation
Analyze	Load growth		Economic growth	Economic growth Load growth Plant closings New homes/condos	Economic growth Load growth Cost of doing business Lower water table Changing land-uses new loads (electric car)
Analyze	Capital requirements	Capital costs	Capital costs	Cost of implementation	Citizens' perceptions /responses to utility actions
Analyze Summarize	Cost of capital				
Analyze	Customer response to DSM			Customer awareness of problems - disbelief that problem exists	Willingness to conserve or alter lifestyles
Summarize	Other	EMF health impacts Thresholds of serious emissions impacts Rate impact-Seabrook Potential for [illegible]	Environmental unknowns Fragility of Transm. losing Cape Cod Which fuels will new plants burn?	Credibility r.e. volatile el. cost Role of utility in welfare provision	health effects of electricity production Erosion

Table 4.5 - Options

Results of discussions with COM/Electric

Consumer Advisory Groups during March 5 - 14, 1990.

Action	COMBINED	CAMBRIDGE	PLYMOUTH	NEW BEDFORD	CAPE COD
Analyze	**Renewables**	Renewables	PV, Wind, Local Hydro,Trash	Trashburners	Renewables
Analyze	**Conservation and Load Management**	Conservation and Load Management	Expanded Conservation and Load Management HVAC subsidies	Conservation and Load Management Innovative rates	Conservation and Load Management Innovative rates Electric Heat-Fuel Substitut'n Standards
Analyze	**Nuclear**	Nuclear	Nuclear		Nuclear
Analyze	**Clean Coal**	Clean Coal	Clean Coal	Clean Coal	Clean Coal
Analyze	**Natural Gas**	Natural Gas			Natural Gas
Analyze	**Non-Utility Generation**	NUGs/IPPs Cogeneration	Cogeneration	NUGs/IPPs Cogeneration	
Analyze	**Power Purchases**	Power Purchases	Canadian hydro	Power Purchases	Power Purchases
Summarize	**Wheeling/Access Restructuring/ Competition**	Wheeling			Wheeling
Analyze	**Repowering**	Repowering	Repowering	Repowering w/coal	Repowering
Summarize	**Others**	Scrubbers on existing plants Do nothing Diversity Location Competition	Diversity	Competition	Competition

On April 4th, 1990, a mailing was sent to the participants providing a schedule of the next meetings, a summary of issues, uncertainties, and options discussed in the initial meetings, and fact sheets about selected options. The mailing also identified the strategies that would be modeled.

4.3 Second Meetings: Interim Results, Prioritizing Attributes and Uncertainties

The second round of external advisory group meetings began in Cambridge on April 23rd, 1990. The purpose of these meetings was to review the overall concerns expressed by the four consumer advisory groups, to present to each group the issues, uncertainties, and options being included in the scenario analysis, and to examine the results for a subset of the scenarios in order to familiarize the participants with various technical concepts.

The predominant issues identified by the four consumer advisory groups were broken down into four general areas: environmental quality, cost of electric service, reliability of electric service, and the efficiency of electric service provision. Sub-issues, and the attributes used to measure them are listed in Table 4.6.

Table 4.6 - Issues and Attributes for the COM/Electric Project

Issue / Sub-Issue	Attributes, or Measures
Environmental Quality	
Acid Rain	SO_2, NO_x, and Particulate Emissions
Ground Level Ozone/Smog	NO_x Emissions
Global Warming	CO_2 Emissions
Land Use	No., Size and Footprint of New Powerplants
Nuclear Waste	High Level Wastes
Cost of Electric Services	
Level of Cost	Total and Unit Cost of Electric Services
Volatility of Costs	Max. Ann. Increase in Cost of Service
Reliability/Adequacy of Electricity Supplies	
Frequency of Shortages	Hours in NEPOOL Emergency Operating Levels
Efficiency of Electric Service Provision	
End-Use Efficiency	Percent Reduction in Peak Load
Supply-Side Efficiency	Percent Increase in Powerplant Efficiency
Total System Efficiency	Product of End-Use and Supply-Side Reductions

The predominant uncertainties identified by the four consumer advisory groups were broken down into three areas: low, base and high (L, B & H) economic/load growth, low and high (L & H) fuel prices, and low, base and high (L, B & H) customer response to demand-side management programs. Changes in capital costs were relegated to secondary status by the analysis team and modeled with base values only, with possible changes for future sensitivity runs. Combining these uncertainties gives a total of 18 futures.

Likewise, the issues and option-sets identified were formulated into 8 supply-side option-sets and 2 demand-side option-sets. The supply-side option-sets could be built to either a base or high target reserve margin, and operated using either low or high sulfur Oil 6 where appropriate. For the consumer advisory group meetings, only two supply-side option-sets were modeled using low sulfur oil, giving a total of 40 strategies and a total of 720 scenarios.

Results from these runs strongly indicated benefits in SO_2 emissions, by switching from high sulfur fuel oil to low sulfur fuel oil. As a result, this fuel substitution was also done for the other six supply-side option-sets. The additional 432 runs required were performed during the months of June and July, bringing the final total to 64 strategies and 1152 scenarios. This final set of strategies and futures is shown in Table 4.7 below.

Table 4.7 - Final Strategies and Futures

Strategies

Option Sets are combined into Strategies

Demand Option Sets

C - Collaborative Process	E - Enhanced Collaborative

Supply Option Sets

(High, Low Sulfur Oil)

A,	B	- Gas Dependent
C,	D	- Repowering
E,	K	- Gas & Coal
F,	L	- Coal Dependent
G,	M	- Coal & Repowering
H,	N	- Canal 3 & Gas
I,	O	- Nuclear & Gas
J,	P	- Photovoltaic & Gas

Combined Strategies (key)

High Sulfur	Low Sulfur	High Sulfur	Low Sulfur
AC	BC	AE	BE
CC	DC	CE	DE
EC	KC	EE	KE
FC	LC	FE	LE
GC	MC	GE	ME
HC	NC	HE	NE
IC	OC	IE	OE
JC	PC	JE	PE

Note: All Supply-Side Options Sets were modeled with both low (23%) and high (30%) reserve margins.

Futures

Uncertainties are combined into futures.

Load Key	Load Growth
L	Low
B	Base
H	High

DSM Key	DSM Responsiveness
L	Low
B	Base
H	High

Fuel Key	Natural Gas Price
L	Low
H	High

Rate Key	Cost of Capital
B	Base
H	High

Note: Cost of capital was left as an uncertainty for sensitivity analysis

These strategies and futures incorporate a number of significant changes from the strategies and futures devised in cooperation with the COM/Elec internal advisory group. These revisions and additions include the following;

1) Technological Supply-Side Option-Sets. The three existing option-sets were modified, two new option-sets were added as modified combinations of the existing sets, and three new options (listed below) were added.

a) Existing Options. The chief change here was a realistic reappraisal of cogeneration potential in COM/Elec's service territory, as compared to the amount of cogeneration built in previous runs. A comparatively small, fixed amount of cogeneration was estimated based on past COM/Elec studies, and added to all option-sets. The relative technology ratios were adjusted for the Gas Dependent, Repowering and Coal & Cogeneration (now just Coal Dependent) option-sets, keeping a minimum of 20% combustion turbines to ensure adequate peaking capacity. In particular, one coal technology option was dropped (Atmospheric Fluidized Bed Combustion), because it was slightly more expensive than coal gasification combined cycle units with no real compensating advantages.

b) Modified Combinations. To determine the effect of intermediate combinations of existing option-sets, the Gas & Coal and Coal & Repowering options sets were added. Since Repowering is a large option of fixed size, the relative contribution of combustion turbines for peaking purposes was increased to 40% of the additional capacity required.

c) New Options. In response to requests from the advisory group, two new technologies (photovoltaics and nuclear) were added. The nuclear option was chosen to be an Advanced Light Water Reactor, with the reduced lead time and costs deemed necessary for the option to be seriously considered. In response to a suggestion by Mr. B. L. Hunt, Manager of Integrated Planning, a *hypothetical* option converting the Canal units 1 and 2 from oil to coal was also added. This option was referred to as Canal 3. All these new options are described in detail in Chapter 5.

2) Operational Supply-Side Options. In addition to the above changes in generation technology choices, two new construction and operation supply-side options were also added.

a) Reserve Margin. In order to see the effect on reliability and service cost, this option of building new capacity to both low (current) and high reserve margins was added for all technological supply-side option-sets.

b) Low Sulfur Oil. Prior runs emphasized the fact that generation by Canal (COM/Elec's only Oil 6 fired plant) has a major effect on SO_2 emissions. For this reason two supply-side option-sets were repeated (Gas Dependent and Repowering), substituting low sulfur Oil 6 (0.5 %) for the current high sulfur Oil 6 (2.2 %).

2) DSM Option-Sets Reduced from Four to Two. Due to the results of the previous analysis, the Collaborative Process (base case) was retained. The Extended Collaborative process was upgraded slightly to the Enhanced Collaborative set, and the No DSM and Technical Potential Cases (used for initial comparison cases) were eliminated.

3) Uncertainties Changed. Based on the previous analysis, several modifications, additions, and subtractions were made to the existing uncertainties.

a) Fuel Prices. Low, base and high fuel prices were initially used for all fuels. In order to study the effect of changes in natural gas availability, base fuel prices were used for all fuels except natural gas, and the price for natural gas was varied between base and high forecasts. This was combined with seasonal use of both spot and firm natural gas for dual-fueled combustion turbine and combined cycle units, as suggested earlier by Mr. B. L. Hunt, Manager of Integrated Planning.

b) Uncertainties Reduced. Due to the very small effect of the Supply Construction and DSM implementation delays (relative to the load growth and fuel price uncertainties), these two delays were eliminated from the analysis.

c) Cost of Capital. The supply-side and DSM 50% capital cost overrun uncertainties were eliminated, and replaced with an uncertainty to investigate the impacts of variable interest rates and the cost of capital. Due to time constraints, this uncertainty was left to be run as an additional, limited sensitivity run.

d) DSM Response Added. In order to study the effect of various customer responses to the different levels of DSM effort, this uncertainty was added. Customer response was modeled as 50% below expected response, 100% of expected response, and 50% above expected response.

The progression of these changes from the initial, internal advisory group scenarios is shown in Table 4.8, along with dates for model runs and meetings. (This table is repeated from Chapter 3 which details the development of initial scenarios by the COM/Elec internal advisory group.)

Table 4.8 - Progression of Scenario Development

Scenarios Sets Evaluated by the COM/Elec - MIT Analysis Team

Strategies Date/Meeting	25-Jul	20-Nov	2-Feb	23-Apr	14-May	10-Jul
Demand-Side Option Sets *	4	4		2		2
Supply-Side Option Sets	3	3		10		8
Reserve Margins				2		2
Hi/Lo Sulfur Oil						2
Total No. of Strategies	12	12		40		64

Futures Date/Meeting	25-Jul	20-Nov	2-Feb	23-Apr	14-May	10-Jul
Load/Economic Growth	3	3		3		3
Fuel Prices	2	3		2		2
DSM Option Delay	2	2				
DSM Option Cost Overrun †	2	2				
DSM Regulatory Treatment †	2					
DSM Customer Response				3		3
Supply Option Delay		2				
Supply Option Cost Overrun †		2				
NUG Dropout Rate	2					
Cost of Capital (Interest) †				2		2
Total No. of Futures	96	144		36		36

Scenarios ***Date/Meeting***	25-Jul	20-Nov	2-Feb	23-Apr	14-May	10-Jul
Total No. of Scenarios	864	1296		1440		2304
Total Runs Required	216	324		720		1152
Total Runs Performed		18	108	48	720	1152

* Strategies with 4 DSM Options have 2 options which cannot be delayed (No DSM & Technical Potential) so the number of runs and scenarios are reduced by 6/8.

† Effects of these uncertainties can be figured after runs are done, and were performed selectively as sensitivity analyses.

A large portion of the second meetings was devoted to bringing the participants up to speed on the details of the scenarios as they were modeled. Thus time was spent exploring the characteristics of the individual supply-side and demand-side options, as well as proportions by which they were combined into option-sets. These characteristics and combinations are covered in Chapter 5 - Description of Final Scenarios, with details in Appendix C.

Results from an initial set of 48 scenarios provided the vehicle for familiarizing the participants with the behavior of COM/Elec's system, and with our methods of presentation (results and conclusions for all 1152 scenarios are presented in Chapter 6 and Appendix D). Using a pared down version of the data analysis strategy described in Chapter 2, we first presented single attribute results. For example, Figure 4.2 shows the performance of selected strategies along the attribute of sulfur dioxide emissions, given uncertainty about gas prices and customer responsiveness to demand-side programs. This quickly revealed that clean coal was the most robust supply-side option-set, because it was impervious to uncertainty about natural gas prices. While the minimum SO_2 values were similar across strategies, the maxima for strategies with gas were higher than those for clean coal. On the demand-side, the Enhanced DSM option-set showed slight benefits over the Collaborative one when coupled with repowering or gas/coal on the supply side. However, increased DSM worked against the clean coal supply-side option-set, leading to higher emissions for reasons that will be explained below. It appeared relatively neutral when combined with a gas-dependent supply-side option-set.

The factors influencing sulfur dioxide emissions (see Figure 4.3) helped to explain this story. As in the New England study, high gas prices led to switching towards dirtier, cheaper fuels such as Oil 6 in the loading order of powerplants. However, since coal was always cheaper than either gas or oil, the coal-dependent strategy was not dramatically affected by the level of gas prices. Further, clean coal plants were able to displace a significant amount of existing base load Oil 6 capacity in the loading order, making coal the new base load technology. On the demand side, the Enhanced option-set in the gas-dependent, repowering, and gas/coal cases displaced new intermediate loaded power plants, never reaching the existing base loaded plants that primarily burned SO_2-producing Oil 6. However, in the clean coal case, DSM displaced some of new base loaded coal plants, preventing them from coming on line and reducing the use of existing Oil 6-fired capacity.

The participants were also introduced to bivariate scatter plots, or tradeoff curve graphs, which showed that choices among strategies often involved tradeoffs, and that uncertainty affected the relative attractiveness of different strategies.

Figure 4.2 - COM/Electric Sulfur Dioxide Emissions for a Subset of Strategies

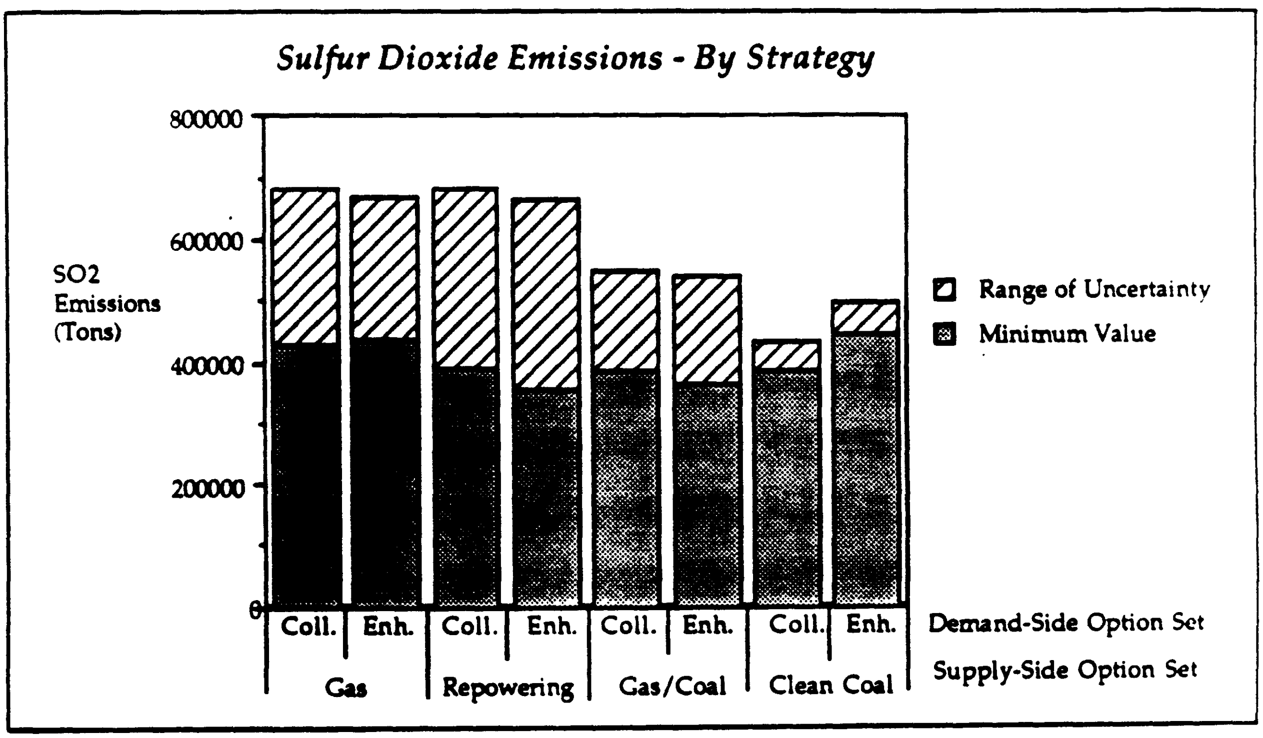
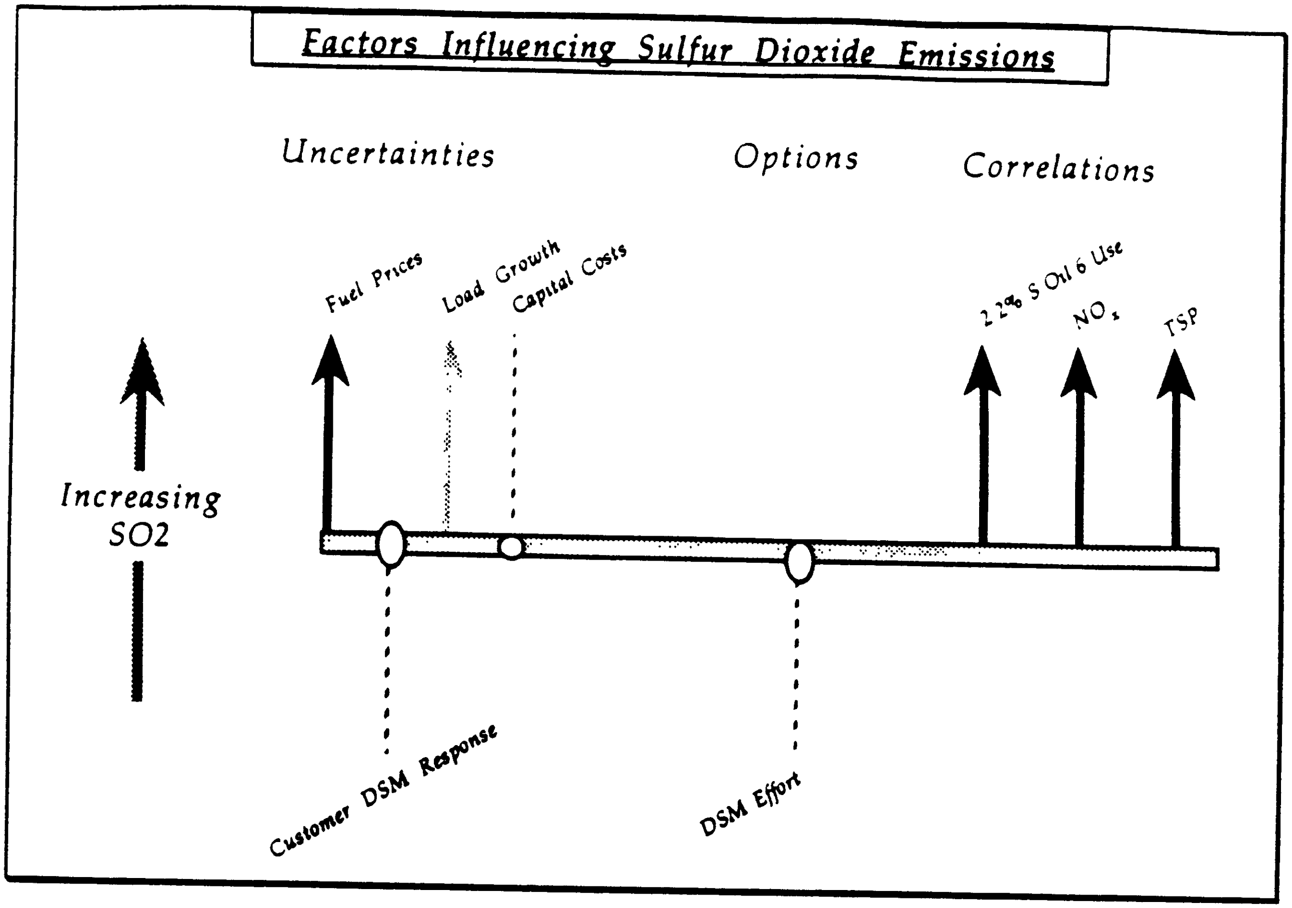


Figure 4.3 - COM/Electric Factors Influencing Sulfur Dioxide Emissions



To the surprise of those analysts who had worried that quantitative information would be incomprehensible, the participants asked the types of questions that suggested that they understood the presentation. For example, in the Cambridge meeting, the head of a neighborhood association remarked after reviewing the SO_2 information shown in Figures 4.2 and 4.3, that "when I save a kilowatthour through conservation, it's just a generic kilowatthour. I'd like to save a dirty old kilowatthour instead of a clean new one." In Plymouth, the president of the local radio station noticed that the change in costs across strategies, especially on the supply side, was relatively small. Therefore, he said, "It seems to be worth investing some capital in insuring against fuel risks and other uncertainties."

The participants asked a variety of questions about underlying assumptions not shown in the viewgraphs. For example, participants in both Hyannis and Plymouth wanted to know what the basis for the electric load forecasts was. Likewise, the county commissioner from Hyannis wanted to know what was the existing fuel mix in the COM/Electric system. Similar questions were asked about the connection between fuel use, investments, costs and rates, DSM response, the operating relationship between COM/Electric and the regional electric grid, specific technologies, trends in electric consumption, emissions reduction strategies, the characteristics of different pollutants, the natural gas marketplace, and other things. One participant (Polaroid's facilities manager) even caught an inconsistency between the MIT numbers and COM/Electric's published data on SO_2 emissions from clean coal power plants (COM/Electric's source was more recent).

The good news was that the people who participated in the second set of meetings were curious, attentive, and benefitted from the sessions. The bad news was that attendance was much lower than in the first meetings. There were only four participants each at the Cambridge, Plymouth, and Hyannis meetings. New Bedford had six, although one was a Cambridge person who preferred the New Bedford meeting date. The small turnout (a classic problem in open planning) was ascribed to various causes by the participants. The head of the newspaper in Plymouth said that the slide show in first meeting had been "overwhelming; we were left wondering what we could possibly contribute to such a complex planning task." In direct contrast, the aide to the state senator in Hyannis said the slide show and issues/uncertainties/options discussion had "aimed too low so that people felt they were being asked to make a complex decision based on inadequate information." The Polaroid representative said that "the lack of numbers on the axes of the graphs in the slide show [removed so as not to "scare" a lay public] had left him and others worried that the discussion would be too general to be of value.

The remaining time in the second meetings was devoted to a questionnaire soliciting the participants' views on the most important attributes to measure, and the types of uncertainties to consider in the planning exercise (see Figure 4.4). The main purpose of the instrument was to find out how to structure the tradeoff analysis discussion in the final set of meetings. The highest priority attributes would form the axes of the initial tradeoff curves, and the values shown would be those for the highest-interest future. It would also provide a measure of the importance the participants placed on different attributes, their aversion to different types of risks, and the degree of consensus attending these value judgements.

Figure 4.4 - COM/Electric 2nd Meeting Questionnaire

What Are Your Views?

Questionnaire to participants in the COM/Electric-MIT open planning project at end of the second meeting. Answers kept confidential.

Please prioritize these issues in order of their importance for this planning effort: (1=most important, 2=important, 3=less important, ..., 8=least important)

_______ Cost of electric service (average level)
_______ Cost of electric service (variability)*

_______ Reliability/outages (average level)
_______ Reliability/outages (variability)*

_______ Local site-related environmental impacts/land use/noise/visual

_______ Regional environmental impacts/acid rain/smog

_______ Global environmental impacts/greenhouse effect

_______ Solid/liquid/nuclear waste streams

_______ Other (specify)_______________________

Please select the combination of future possibilities that <u>you</u> consider to be the most important for COM/Electric to anticipate in its plans. Check one in each column.

Electric Load <u>Growth</u>	Fuel <u>Prices</u>	Consumer Response to Utility <u>Conservation Programs</u>	Capital <u>Costs</u>
Low _______	Low _______	Low _______	Steady_______
Med _______		Med ____	
High _______	High _______	High _______	Higher_______

Your name (optional) _______________________

Please hand this in before you leave. Thank you for your input.

* The average level of cost or reliability is its magnitude, on average, over the long run. Its variability reflects the degree to which it changes from one year to the next, and its sensitivity to uncertainties.

4.4 Third Meetings: Final Results and Eliciting Preferences

The final set of advisory group meetings began in Cambridge on May 14th, 1990. Their goal was to understand the participants' preferences regarding COM/Electric's planning choices. The specific agenda included reviewing the scope of the study, reporting on the participants' views as shown in the questionnaire, evaluating the performance of the options to thereby identify the small set of "best strategies", and discussing tradeoffs – characterizing the preferred strategy(ies) from the participants' points of view.

All 720 of the scenarios described in the previous section had been run for this meeting. Thus, the multi-attribute performance of forty strategies across eighteen different futures was available to be shared with the groups. The questionnaire responses guided the presentation of this material, as described above. Table 4.9 shows how the participants prioritized the issues in order of their importance for this planning effort. Overall priorities were based on the rank sums (not scores as in previous questionnaires) of individual questionnaire responses, including three questionnaires mailed by people who had not been able to attend the previous meeting.

Table 4.9 - COM/Electric Issue/Attribute Prioritization

Priority	Issue	Attributes, or Measures	Rank Sum
1	**Regional Environment**	SO_2, NO_x, and Particulate Emissions	58
2	**Cost of Electric Service**	Total Cost of Electric Services	69
3	Reliability	Hours in NEPOOL Emergency Operation Level	80
4	Global Environment	CO_2 Emissions	91
5	Variability of Costs	Maximum Ann. Increase in Cost of Service	94
6	Local Environment	No., Size and Footprint of New Plants	103
7	Waste Streams	High Level Wastes	105
8	Variability in Reliability	Minimum Annual Reserve Margin	116

Only the top two attributes – regional environment and cost of service – were consistently highly ranked across all service districts. Others such as reliability, global environment, and waste streams were highly ranked in some meetings and ignored in others. The participants' profession also seemed to matter, with business people, for example, placing a higher emphasis on cost than others. The data set as a whole had a Friedman test statistic of 22.65, which implied consistency at the .998 level of probability (assuming a chi-square distribution with seven degrees of freedom, per Pindyck & Rubinfeld, 1981). Based on these responses, the analysis team focused first on SO_2 and cost tradeoffs, and later brought in reliability and CO_2 emissions.

According to the groups, the most important future possibilities for COM/Electric to anticipate in its plans deserved to be prioritized as shown in Table 4.10. Overall priorities were based on the sums of individual questionnaire responses.

Table 4.10 - COM/Electric Uncertainty Prioritization

Level		Uncertainty	(Votes Received/Total Votes)
Low	*(2)*		
Medium		**Electric Load Growth**	(12/21)
High	*(7)*		
Low	*(6)*		
High		**Fuel Prices**	(15/21)
Low	*(3)*		
Medium	*(9)*		
High		**Customer Response to Utility Conservation Programs**	(9/21)
Steady		**Capital Costs**	(16/21)
Higher	*(5)*		

The highest-interest future, based on the questionnaire responses, was that with Base load growth, Base capital costs, High DSM responsiveness, and High natural gas prices, or BBHH in the modeling terminology. This showed fuel-side risk-aversion, but optimism regarding DSM investments. This was the future for which the initial tradeoffs were presented.

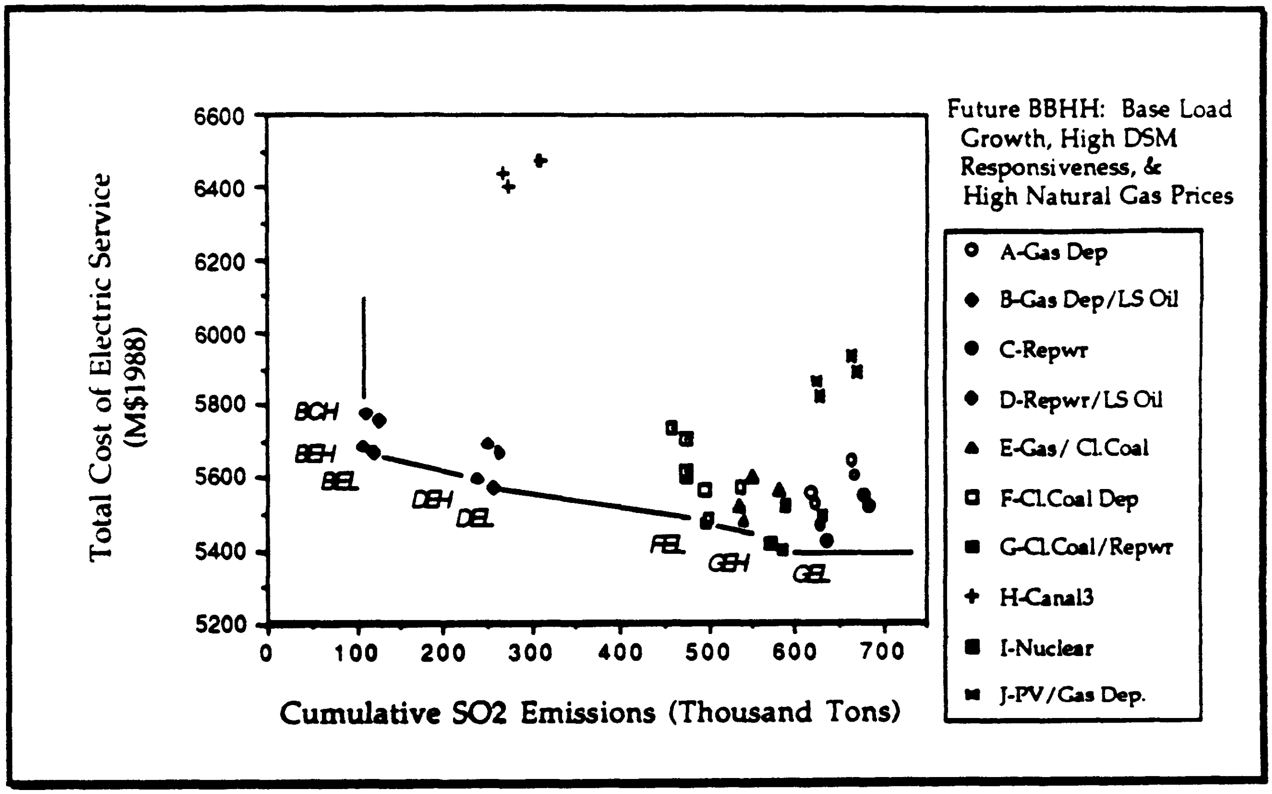
Before tackling real tradeoff curves with the advisory groups, the facilitator reviewed the concepts of dominance, uncertainty, and robustness as they relate to tradeoff curves. These concepts were then tied to the way different tradeoff curve decisions are related to the analysis team's and advisory groups' roles. This discussion and the related graphs are covered by Figures 2.3 through 2.6 in Chapter 2.

Discussion of real tradeoff curves then commenced. Starting with the highest priority attributes (cost and SO_2 emissions), and using values for future BBHH, the performance of the various strategies was examined. Figure 4.5, for example, revealed several important things. In this figure the strategies were identified by supply-side option-set, so that there were four of each (2 DSM option-sets x 2 reserve margins). The figure clearly showed that several strategies were inferior: all of the 'H's' and 'J's', for example.

Supply-side option-set 'H' (or Canal 3 & Gas, as mentioned earlier in this chapter) was based on a proposal by one of the COM/Electric planners to add a clean coal unit to the existing Canal site, and to convert the existing units from Oil 6 to coal gas by building an over-sized coal gasification system. The high capital costs and low operating efficiency of such an arrangement made it an inferior option.

Supply-side option-set 'J' (or solar photovoltaics with gas) was proposed by the advisory groups, and consisted of placing solar cells on 50% of the existing residential roof area and 20% of the commercial roof area in the COM/Electric service territory by 2005, at a unit price of one half of today's price. The remaining capacity needs would be met with gas-dependent technologies. The weak point in this concept turned out to be the fact that COM/Electric's annual peak demand occurred on winter evenings when the sun did not shine; therefore the photovoltaic arrays did not avoid the expense of building new capacity, but only reduced the annual energy production by other sources.

Figure 4.5 - COM/Electric Total Cost of Electric Service vs. SO_2 Emissions – by Supply-Side Option-Set



Strategies lying along the frontier consisted of low sulfur oil #6 and clean coal (B, D, F, G). The low sulfur Oil 6 strategies (B, D) cost about 5% more than the clean coal strategies (F, G), but had 70% lower SO_2 emissions.

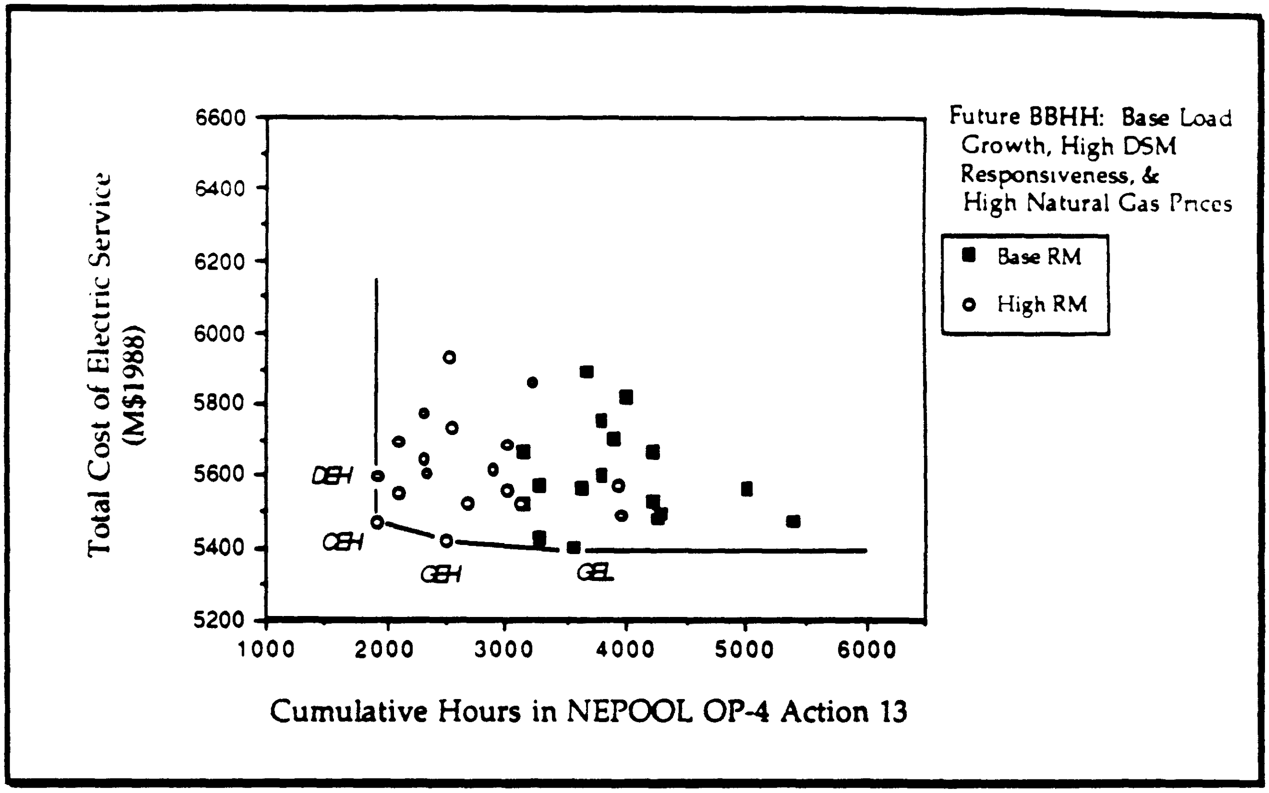
A close look at the patterns within each supply-side option-set's grouping of four strategies revealed important information about the demand-side. The

Enhanced DSM option-set (_E_) always had lower costs than the Collaborative (_C_) with approximately the same level of SO_2 emissions. Thus the Enhanced strategies claimed the frontier in every case (except for 'BCH/BEH', when both made it).

Examining the groupings of four for the effects of reserve margin was also useful. The high reserve margin strategies (__H) always had lower SO_2 emissions and a slightly higher cost than those with the lower reserve margin (__L). Looking at the (B__) grouping, most participants agreed that the preferred combination was to choose Enhanced DSM to lower costs, but then to "buy" some SO_2 reduction by selecting the higher reserve margin, thus choosing strategy 'BEH', for example.

The benefits of this approach were reinforced when the participants viewed a tradeoff graph incorporating the third-ranked attribute of reliability (see Figure 4.6). There the high reserve margin cases (__H) consistently claimed the tradeoff frontier from the lower reserve margin strategies (__L).

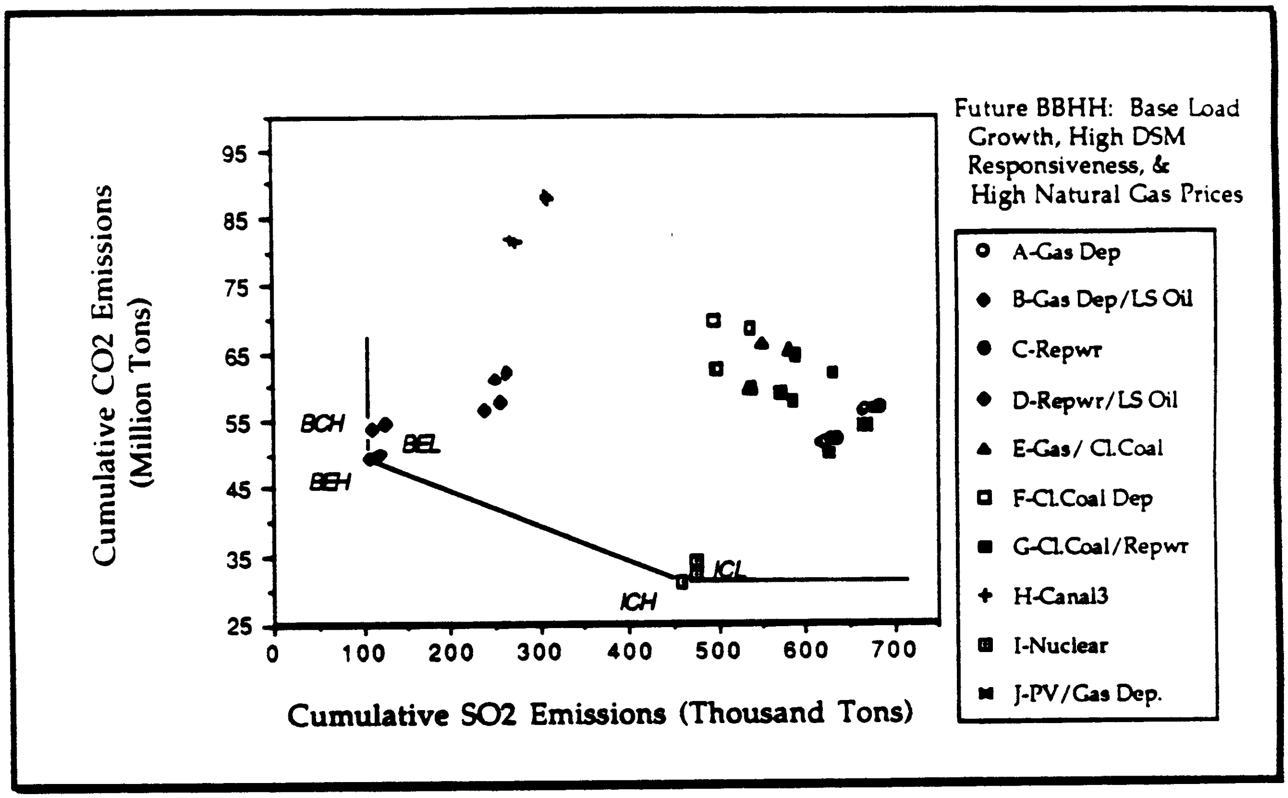
Figure 4.6 - COM/Electric Total Cost of Electric Service vs. Reliance on Emergency Interruptions– by Reserve Margin



The fourth-ranked attribute was CO_2 emissions. The global environment vs. regional environment tradeoff shown in Figure 4.7 made decision making more difficult. While some previously favored strategies such as 'BEH' remained on the frontier, CO_2 concerns brought nuclear (I), a non-fossil option, into the picture. This in turn brought the production of nuclear wastes, heretofore ranked low at seventh priority, to be shown as a decisionmaking attribute.

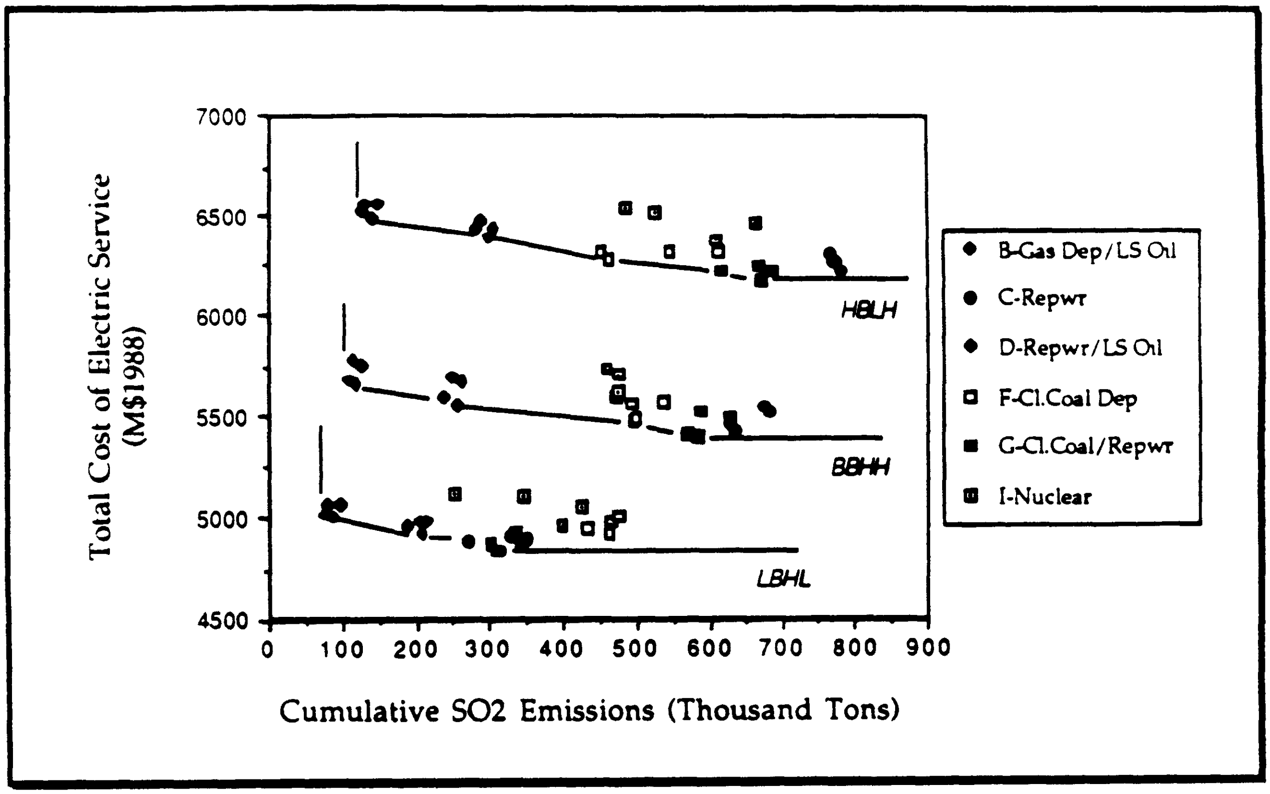
When planning for the meetings, the analysis team discussed the idea of eliciting the participants' preferences regarding which decision rule to use in dealing with uncertainty. Should tradeoffs be weighed using the most popular future, based on the questionnaire? Should a risk-averse (maximin) approach minimizing down-side risks be used by weighing tradeoffs based on the worst future? Should an optimistic (maximax) approach maximizing the up-side benefits be used by weighing tradeoffs based on the best future? Or should an approach emphasizing accountability (minimax regret) that minimized the difference between the best and worst futures be used? The team decided to simply show all three futures to the advisory groups, and let the decision rule remain implicit in their final choice of a strategy.

Figure 4.7 - COM/Electric CO_2 vs. SO_2 Emissions
- by Supply-Side Option-Set



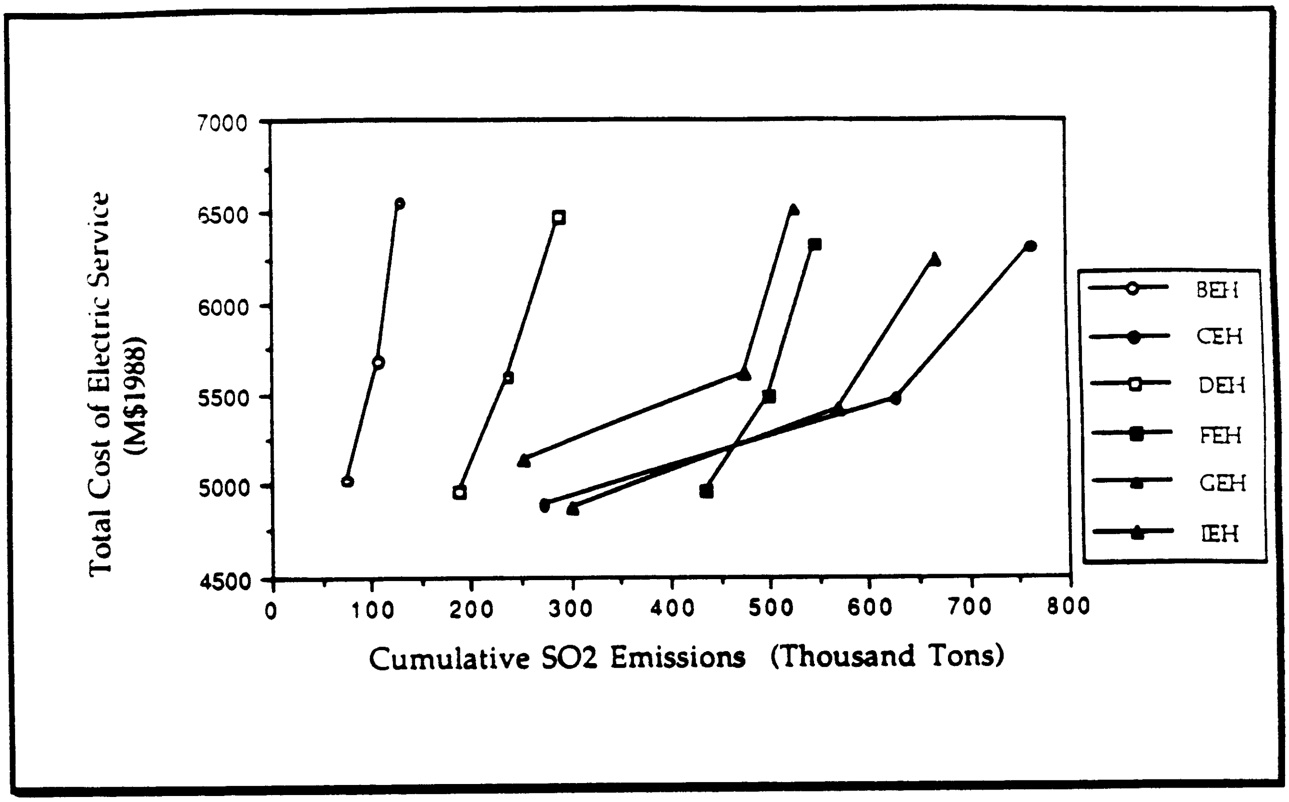
The effects of uncertainty were explored by showing (in Figure 4.8) the decision sets or tradeoff frontiers for each of three futures: the highest-interest (BBHH), the worst (HBLH), and the best (LBHL). Bracketing the results by displaying the best and worst futures made the participants more comfortable with the robustness of the findings. Some of the most interesting strategies (BEH, for example) maintained the same relative positions in all three futures.

Figure 4.8 - COM/Electric Total Cost of Electric Service vs. SO_2 Emissions - by Supply-Side Option-Set for Highest-Interest, Best, and Worst Futures



However, the comparison across futures also revealed the vulnerability of some strategies to uncertainty. Figure 4.9 showed the migration of strategies through cost/SO_2 space for different futures. As can be seen, they all migrated about the same distance along the cost axis between the best and worst futures. Differences were revealed along the SO_2 axis.

Figure 4.9 - COM/Electric Total Cost of Electric Service vs. SO_2 Emissions - Migration across Highest-Interest, Best, and Worst Futures for Dominant Strategies



Strategies 'CEH' and 'GEH' showed much larger SO_2 emissions in the worst future than in the best future in Figure 4.9. Both of these strategies included repowering of existing plants with gas, and using expensive oil 2 as the backup fuel. These strategies were particularly vulnerable to changing gas prices, because with higher gas prices cheaper but dirtier existing plants (burning Oil 6) would operate more, leading to higher SO_2 emissions. Similar strategies incorporating low sulfur Oil 6 did not suffer this weakness (compare 'CEH' to 'DEH', for example).

The participants waded through the graphs shown here, plus many others, in sessions that were designed to be much more interactive than the second set had been. Backup graphs explaining the effects of uncertainty and reviewing modeling assumptions were all available if needed by the group. Such viewgraphs included the univariate performance of strategies for a large variety of attributes ranging from the consumption of specific fuels to levels of spent nuclear waste. Most of the backup material was not needed, because most questions were adequately answered verbally.

To assist the participants in selecting their preferred strategy, a table summarizing the trends identified by the tradeoff analysis was presented (see Table 4.11). A '+' symbol meant that the strategy helped along that attribute (where lower was better), a '–' symbol meant that it hurt, a '±' symbol meant that the outcome was highly sensitive to uncertainty, and a blank space meant that the strategy made little difference one way or the other. Larger and bolder symbols indicated larger impacts.

One reason for providing the summary table was to ensure that participants considered the whole range of attributes in their decisions. However, most of the groups found that the information in the matrix had been reduced too much to be useful, and that, when creating it, the analysts had imposed subjective judgements different from their own, thereby tainting it. They therefore preferred to work off of the tradeoff graphs Figures 4.5 through 4.9 in making their decisions.

Table 4.11 - Trends Identified by the Tradeoff Analysis
in the COM/Electric Data Set

Trends Identified by the Tradeoff Analysis

Issue	Regional Envir.	Cost	Reli-ability	Global Envir.	Waste Streams	Local Envir.	Variab. of Costs	Variab of Rel.	Other Issues
Attribute	SO2	Total Cost	Emerg. Hrs.	CO2	Nucl. Waste	New Sites	Max. $ ΔS	Min. RM	
Strategy/Option									
Demand-Side Management				+	+	+			
Higher Reserve Margin	+		+	+				+	
A - Gas Dependent	±					-			
B - Gas Depend't & Clean Oil	+	-				-			
C - Repowering	±								
D - Repowering & Clean Oil	+								
E - Gas & Clean Coal				-		-			
F - Clean Coal Dependent				—		-			
G - Clean Coal & Repower'g				-					
H - Canal 3 (Clean Coal)	+	—		—			—		
I - Nuclear	+	-		+	—	-	-		
J - Photovoltaics & Gas	±	-		+		-			

The analysts sought to develop a method for the facilitator to use in eliciting the participants' preferences that revealed the groups' valuations of environmental externalities. One part of this method was to put cost on one axis of many of the tradeoff plots, so that the tradeoffs of various environmental attributes against cost would be clear (see Figures 4.5, 4.8, and 4.9, for example). A second part of this method was in the voting order: they would start with the cheapest strategy, and tally the number of votes for each strategy in order of increasing cost. This would reveal: (1) the implicit valuation, or shadow price of the environmental attribute in dollar terms assuming all else constant, and (2) any thresholds or non-linearities in attribute valuations. The third part of this method was to develop "synonym attributes" to help the participants get a feel for what the differences among strategies really meant. For example, in addition to showing graphs using total cost of electric service as the cost attribute, the analysts also had backup graphs displaying ¢/kWh differences, unit cost of electric service differences, and percent cost differences. This valuation method was not closely followed in practice, for reasons discussed below.

How did the decision making exercise turn out? The Cambridge meeting, as before, had four participants, with a fifth attending the New Bedford meeting because of a scheduling conflict. The meeting ended in consensus, with strategy 'BEH' (gas-dependent supply capacity, clean Oil 6, Enhanced DSM, and high reserve margin) being the first choice, followed by 'DEH' (which included repowering). They also expressed interest in seeing how a hybrid strategy consisting of 'GEH' plus clean Oil 6 for existing plants would perform. The nuclear option (IEH) was taken off the table on the strength of one participant's demand to "throw it out" and no objections from the other participants not to do so.

The Plymouth meeting on May 15th, 1990 had only two participants, so the time was used for a discussion of how to make an open planning process work, instead of the technical discussion of tradeoffs.

There were five participants at the Hyannis meeting, and they engaged in a fairly spirited discussion of tradeoffs. They were able to reach a consensus on the concept of paying higher electricity bills to clean up the environment, at least to the 6% range shown in Figure 4.5 as the difference between the cheapest and least-SO_2-emitting strategies ('GEL' and 'BEH'). They also endorsed the concepts of high-DSM and a higher reserve margin. However, they were unable to reach consensus about whether to minimize SO_2 emissions by choosing a strategy such as 'BEH' or to minimize CO_2 emissions with a hybrid strategy using new nuclear and clean Oil 6 in existing plants. One of the sticking points in this discussion was that nuclear wastes were an overriding concern of one of the participants, who preferred the known problems of SO_2 and CO_2 emissions rather than the less-known problem of nuclear waste disposal.

The final New Bedford meeting had a low turnout, with only three participants, including one from Cambridge. However, the discussion was quite animated, and the group was unable to reach a consensus. They did agree on the value of high-DSM and a higher reserve margin, but could not agree whether to choose a low-cost or low-emissions supply-side option. While all agreed that an 80% SO_2 reduction for a 6% cost increase sounded quite cost-effective, an industrial electricity customer pointed out that industries worked very hard to shave 6% off of their electric bills, and that this amount significantly affected their competitiveness. All of the participants said that they "needed more time to chew on it and toss it around."

Several things thus hindered a definitive outcome of the experiment. First, the small number of participants negated any possible claim to having elicited truly representative public preferences. Second, seemingly better hybrid options were invented during the preference elicitation process. These would have to be modeled and placed on the tradeoff curves before the participants would be willing to negotiate tough strategy-specific tradeoffs between cost and environmental quality. Finally, the participants ran out of time. They were just warming up to their arguments when the last meetings ended; participants in New Bedford, for example, stayed on for an extra hour of discussion with the analysis team about the experiment.

4.5 Efficacy of the COM/Electric Open Planning Project

The COM/Electric open planning project was initiated for several reasons, as stated earlier: to improve the credibility of the Company's resource planning method, to better integrate demand- and supply-side planning, to include environmental impacts in the planning process, and increase the level and quality of public participation. The initial experiment with four consumer advisory groups revealed a number of useful things about both the analysis technique and the process.

The experiment demonstrated that it was feasible to conduct exhaustive analysis in a scenario-based multi-attribute tradeoff framework with a quick turn around time – just over two months separated the first advisory group meeting from the last. In that time, issues were defined, 720 scenarios were developed and analyzed, presentations replete with graphics were prepared, and a dozen meetings were facilitated. It took a year to get the integrated modeling system up and running, but once in place, the scenario analysis task was manageable.

The experiment demonstrated the value of the technique for finding robust strategies that: (1) integrated demand- and supply-side options together into a coherent plan, (2) explored the effects of uncertainty on performance, and (3) incorporated consideration of environmental impacts. This suggests that it may be a useful part of the overall planning method that the company is developing to satisfy regulatory concerns.

Some of the information sharing techniques used in the presentations worked, while others did not. They are listed and rated in Table 4.12.

Table 4.12 - Efficacy of Techniques as Applied on the COM/Electric Project

Techniques Used on the COM/Electric Project	Useful to Analysis Team?	Useful to Advisory Groups?
Line graphs to show trends over time	Yes	Yes
Column graphs to show performance of strategies along a single attribute, plus the range of uncertainty	Yes	Yes
Arrow charts to show the factors influencing an attribute's value, and the direction of that influence, including uncertainties, options, and correlations	Yes	Yes
Scatterplots to show tradeoffs between two attributes. for many strategies, within a single future	Yes	Yes
Scatterplots to show tradeoffs between two attributes for many strategies, across several futures	Yes	Yes
Line plots to show migration of strategies in two-attribute space across futures	Yes	Yes
Matrix (strategies by attributes) summarizing trends identified by the tradeoff analysis	Yes	No
Questionnaire eliciting preferences	Yes	Yes
Voting by show of hands for priority issues	Yes	Yes
Showing results for the best and worst futures to bracket the analysis of uncertainty	Yes	Yes
Asking the participants to prioritize attributes	Yes	Yes
Asking the participants to prioritize uncertainties for utility to anticipate in its plans	Yes	Yes
Asking the participants to choose a specific preferred strategy	Yes	No
Asking participants to characterize a preferred strategy in multi-attribute space	Yes	Yes
Sharing intermediate results with participants	Yes	No

The biggest single surprise to the analysts was that most participants preferred to look at scatterplot tradeoff curves rather than summary matrices when making choices. Even though one participant said that the dots representing strategies "looked like bugs squashed on the screen" he still liked that form of display.

At the end of each of the third sessions, the participants were asked to answer to a series of wrap-up questions. These are discussed below.

Was there a consensus? The answer was yes in Cambridge, but it was a qualified no elsewhere. In Plymouth, the president of the radio station said that he felt uncomfortable deciding among strategies; that he was willing to offer philosophy but not make technical choices. In Hyannis, participants agreed on some "all-gain" components (high-DSM and higher reserve margin) and were willing to make final choices among strategies, but could only agree on a philosophical point – that increasing costs by 7% to reduce environmental damage was a good idea. In New Bedford there was also agreement on more DSM and the higher reserve margin, but not on the level of cost vs. environment tradeoff to make. Participants pointed out that there was agreement that certain strategies (such as H - Canal 3 & Gas) could be ruled out.

Were there differences of opinion? The answer here was unanimous – yes. Participants held different views on which attributes were most important, which uncertainties ought to be planned for, and which differences in attribute values were significant. However, this did not prevent them from agreeing about some things such as the value of demand-side management and a higher reserve margin.

Were the presentations comprehensible? The slide show in the first session received low marks from many people. One participant said it was "overpowering," while another said that "it didn't offer enough substance to busy people who, it seemed, were being asked to make complex decisions on the basis of inadequate information." These same people said that the second and third meetings resolved both problems, and that the presentation graphics in those meetings were generally good. Specific parts of those presentations were rated in Table 4.12 above.

Were the presentations credible? The answers to this question were largely yes. Several people said that the movements of points on the graphs registered intuitively, and that it was useful to be shown the big picture. One person said that the credibility of the results was "unquestioned," but others added qualifiers, one asking herself "what was left out of the model?" while another stated that "the presence of academics built the credibility." During the meetings there were lots of questions about the modeling assumptions used that were answered either immediately or in subsequent meetings. One participant felt that the long, three session process was important in establishing credibility, saying "it can't go into a single session, you'll just get blank looks." However, another insisted that "perception is the key to credibility, not strength of detail."

Were the sessions useful, constructive, and on the mark? The participants provided a variety of answers. One said that "the process could have gone on without the participants – except for the attribute prioritization stage." Another "appreciated the openness of the process, but felt uncomfortable offering untutored opinions." Another stressed its educational value, saying, "I learned what to do in my own home regarding conservation, and that there exist tradeoffs between cost and the environment." Similarly, another said "a different understanding of the power industry has certainly developed in me." For one participant, it was refreshing "to get off single option solutions" and look at multi-option strategies, and to identify some "win-win situations." Another commented that he was glad that the utility sought feedback on its plans, and appreciated the need to get into the complexities of the problem, but felt that the utility should make the expert choice after asking peoples' general preferences. He used the analogy of the auto mechanic, who "is the only one who knows how the engine works" and who should therefore fix the engine.

All of these comments suggested that, at a minimum, the meetings had public relations value. In fact, several of the participants said "what's going to happen with this input?...Don't let it die here...Get across to the public that COM/Electric is trying to get people involved."

Participants, while mentioning that the "canned" first meeting had been something of a turn-off, also pointed out that "attrition rates are high in all public meetings' and that it probably will be necessary to develop a multi-faceted program to keep in touch with people. Several stressed the need to ensure that a more representative sample of the public should participate, including especially the poor elderly and young families for whom a 6% price increase might be significant.

In conclusion, the initial experiment with open planning at COM/Electric seemed more successful at getting public input for prioritizing attributes and assessing risk aversion than for achieving consensus on specific planning choices involving tradeoffs. Where all-gain outcomes were revealed, as with high-DSM and higher reserve margins, consensus was possible. Where tradeoffs had to be made, it was more difficult. Both more time and more analysis (of hybrid strategies) were needed. The process certainly inspired both the participants and analysts to suggest improved hybrid strategies, such as clean coal with repowering and low sulfur oil, plus high-DSM and higher reserve margin. As such, it played a vital role in spurring inventiveness in the planning debate, and in improving the image of the company, but did not reach closure on decision making.

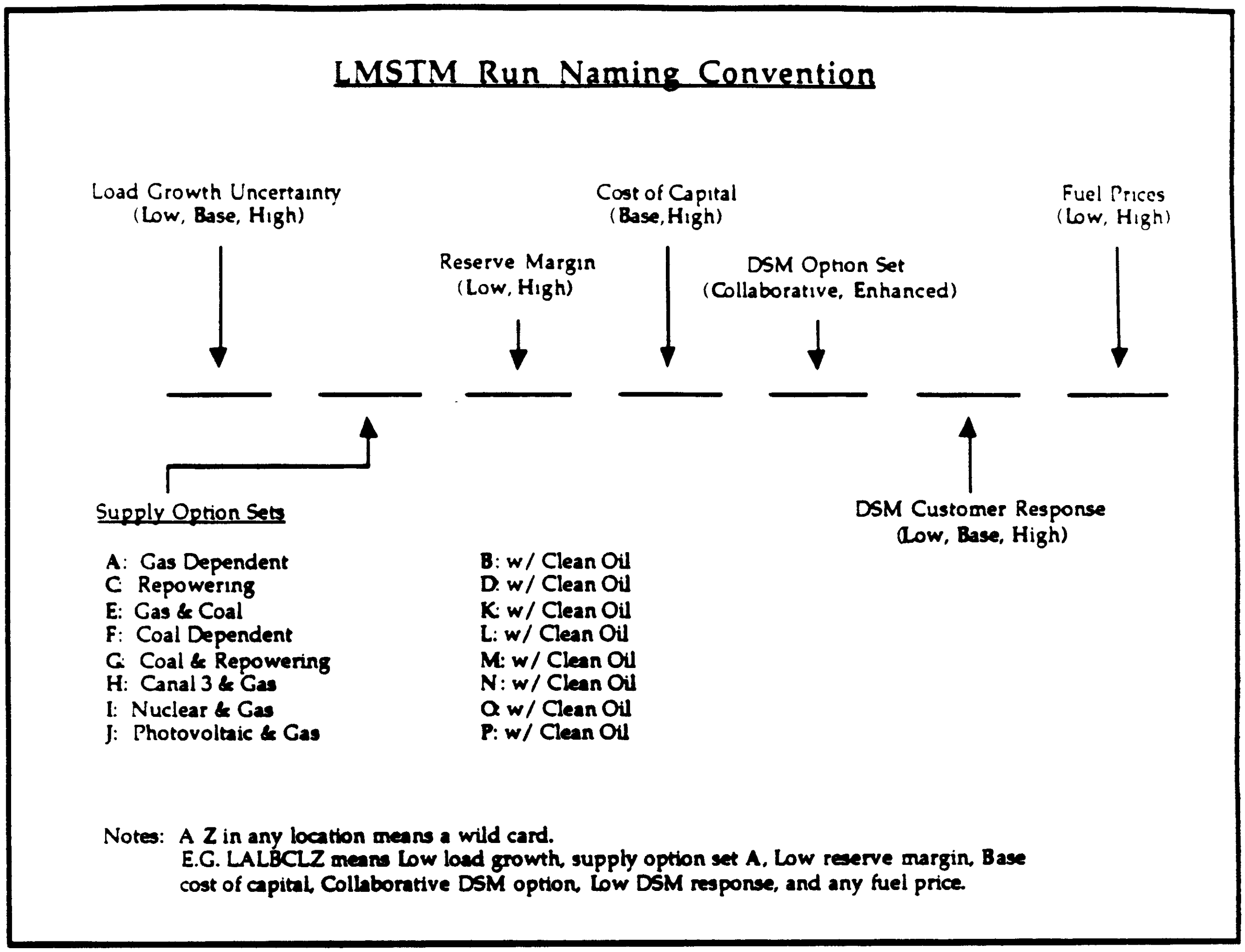
5.0 Description of Final Scenarios

This chapter describes the input for the final set of LMSTM model runs performed for and following the external consumer advisory group meetings. It also includes the additional "hybrid" strategies recommended by the consumer advisory groups for additional analysis. First, the naming convention for each scenario is presented. Next, the supply-side option-sets are described, followed by the demand-side option-sets, the uncertainty information, and finally input assumptions such as emissions rates, and reserve capacity under NEPOOL Operating Procedure 4 actions. Trends are graphed, and sources are mentioned. For detailed numbers and references, the reader should refer to Appendix C.

5.1 Scenario Name Definition

Each scenario modeled was given a unique 7 character name. Within this seven character name, each letter represents the choice or state of a different uncertainty or option-set. This naming convention is shown in Figure 5.1 below.

Figure 5.1 - Run Naming Convention



5.2 Supply-Side Options

Supply-side options are made up of different amounts and types of generating capacity which the LMSTM model may dispatch in order to meet electrical load. This includes existing powerplants, new powerplants (planned as either firm or scenario-specific), and "virtual" units which emulate either power purchase contracts or OP-4 outage states. In addition to new or existing powerplants, a supply-side option-set may also consist of how these plants are planned (the target reserve margin) or operated (fuel changes). Each of these options is described below.

Existing and Firm Capacity

This category includes all existing capacity and firm commitments for the future, as summarized in Figure 5.2 - COM/Elec Existing and Firm Capacity. This figure shows each unit, purchase contract and small hydro and cogeneration purchase, with the fuel and on-line or retirement dates.

The data for these units was obtained from Mr. Paul Krawczyk in the form of an existing LMSTM input file. It was thoroughly reviewed and uncertain data confirmed by phone conversations. The information was checked and updated as new data became available (e.g. fuel and O&M cost escalation data from Data Resources, Inc.). Because this data was obtained from COM/Elec, it is excluded from Appendix A - Detailed Input Assumptions. However, new firm commitments that apply in every scenario (such as new cogeneration) are included in Appendix A and Figure 5.2.

Figure 5.2 - COM/Elec Existing and Firm Capacity (MW)

PLANT	FUEL	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Conn	Nuclear	26.42																								
Rowe	Nuclear	7.81																								
Vern	Nuclear	11.70																								
Maine	Nuclear	30.71																								
Pilgrim	Nuclear	73.70					-73.70																			
PtLeP	Nuclear	25.00			-25.00																					
Canal 1	2.2 Sul	143.00																								
Canal 2	2.2 Sul	292.00																								
KSteam	0.5 Sul	6.00																								
Kendall1	0.5 Sul	19.00													-19.00											
Kendall2	0.5 Sul	18.00													-18.00											
Kendall3	0.5 Sul	29.00													-29.00											
Blkst 1	0.5 Sul	16.00					-16.00																			
Blkst 3	0.5 Sul	2.75					-2.75																			
Blkst 4	0.5 Sul	2.60					-2.60																			
Jet 1	Kero	24.00																								
Jet 2	Kero	24.00																								
Wyman	0.5 Sul	8.87																								
Cannon1	1.0 Sul	25.40									-25.40															
Cannon 2	1.0 Sul	35.20									-35.20															
OBDiesel	Diesel	8.25																								
WTDiesel	Diesel	5.50																								
SBK 1	Nuclear		60.50																							
NUST 89	Purchase	70.37				-70.37																				
NUST 92	Purchase				30.47		-30.47																			
Slice 70	Purchase	70.00		-70.00																						
Slice 60	Purchase		60.00				-60.00																			
Slice 60	Purchase					60.00		-60.00																		
NUPK 88	Purchase	18.40	-18.40																							
NUPK 89	Purchase	3.90	-3.90																							
NUPK90	Purchase		30.24	-30.24																						
Slice 50	Purchase	50.00	-50.00																							
Hydro Qbec	Purchase			58.00																						
BtMill	Hydro	20.00																								
Pioneer	Hydro	1.19																								
Collins	Hydro	1.03																								
Chicopee	Hydro	2.17																								
CTC	Cogen	26.80																					26.80			
NEA	Cogen				46.00																					
Tondu	Cogen				47.00																				47.00	
PPA	Cogen		34.60																							
SoMass	Cogen	46.18																								
SoMass2	Cogen				22.50																					
NBCogen	Cogen				83.00																	83.00				
WheelBr	Cogen					42.00																42.00				
ModWay	Cogen				9.75																	9.75				
HuntRd	Cogen			0.68																	0.68					
MIT	Cogen					20.00																				
C/E Cust	Cogen				3.50	7.00	11.00	4.50	4.00																	
TOTAL		1145.0	73.0	-41.6	217.2	59.4	-154.5	-55.5	4.0	0.0	-60.6	0.0	0.0	0.0	-66.0	0.0	0.0	0.0	0.0	0.0	0.7	134.8	26.8	0.0	47.0	0.0
CUM		1145.0	1218.0	1176.4	1393.7	1453.1	1298.6	1243.1	1247.1	1247.1	1186.5	1186.5	1186.5	1186.5	1120.5	1120.5	1120.5	1120.5	1120.5	1120.5	1119.8	985.0	958.2	958.2	911.2	911.2

The existing capacity base is not described here because it and all updates were obtained from COM/Elec and because it is too long to summarize. However, it does incorporate some assumptions which should be mentioned.

1) Power Purchases. These contracts are modeled as generating units, which "retire" when the contracts expire. All contracts are with Northeast Utilities (NU), except for a single purchase from Hydro Quebec, and represent either a specific type of capacity (steam or peaking units) or a "slice" of the entire NU system. Pollution exported from the COM/Elec service territory through power purchases was included in total emissions, and the emissions from each purchase "unit" reflect the blend of capacity types given by the contract. Because projected regional capacity is limited, no further contracts are indicated beyond those currently in place.
Due to the nature of these contracts, and the fact that both Northeast Utilities and COM/Elec are in the same power pool, the question was raised whether power purchases could be included as capacity available during peak load hours, and used in calculating the reserve margin for planning new capacity required. The choice was made to include such contracts in peak capacity, but the impact was small since the last contract expires in 1995, and subsequent planning was unaffected.

2) Retirements/Life Extension. The only retirements included in the initial LMSTM database were for COM/Elec's share of the Pilgrim and Pt. LePreau nuclear units (74 MW in '94 and 25 MW in '92, respectively), and for several cogeneration units. In view of the advanced age of the Blackstone, Cannon, and Kendall units, it was felt that a finite life was more reasonable than the alternate default choice of indefinitely prolonged operation (life extension). It

was therefore chosen to retire these units in '94, '98, and '02 respectively. Only for the repowering strategies were these sites upgraded with additional capacity and returned to service following the retirement dates. In contrast, it was assumed that the Canal plant would receive sufficient maintenance and/or life extension to keep its units operating through the end of the study period (2013).

3) Cogeneration. COM/Elec's LMSTM database includes 10 cogenerators totalling 358.5 MW as firm present and future capacity. However, working from COM/Elec's February, 1988 survey of 87 customers (including 17 feasibility studies), it was decided that only an additional 30 MW might be available, based on the size, number, and required payback period of projects studied. This cogeneration was assumed to be in the form of gas turbine topping cycle units, and was phased in between 1992 and 1996 as a single must-run unit. Because the estimated size of this resource was so small, it was considered as a firm, fixed capacity resource added to the existing unit database for all scenarios. The currently planned MIT cogeneration project of 20.8 MW was modeled to come on line as projected in 1993.

4) Thermal/Steam Load. The original COM/Elec LMSTM database included as firm capacity 6 MW of steam supplied by the Kendall plant for district heating purposes (unit KSTEAM). Since this capacity was not available to meet peak load (or any electrical load), the unit was removed from the model for the final set of runs. Fuel consumption results are therefore based on electrical demand only, and will be slightly lower than actual. Given the small size of this unit, the effect of this change on total emissions was negligible.

New Capacity

New, scenario-dependent capacity options for the model were broken into two different types; those of fixed size, and those of fixed ratio. Fixed size options are just that - a fixed number of MW in one or more units that may come on line all at once or over time. Fixed size options depend only on the supply-side option-set, and do not depend on uncertainties which affect load growth. For example, repowering is a fixed size option where several rebuilt and expanded units are brought (back) on line over several years.

For fixed ratio options as many identical units are built as required to fill some target ratio or fraction of the gap between existing capacity and the anticipated capacity required. The number of fixed-ratio units built for a given supply-side option-set varies between scenarios, depending on net load growth. Planning the number of fixed ratio units to be built under different future loads and automating the construction of supply input files was performed by Fortran programs described in Chapter 3.

An abbreviated list of operating characteristics for both new fixed-size and fixed-ratio supply technology options is shown below in Figure 5.3 - COM/Elec Supply-Side Option Characteristics. This is then followed by a basic description and block diagram for each technology.

It may be noted that the supply-side options shown have an addition or purchase size that is smaller than the absolute unit size. Because COM/Elec is a relatively small system, a single medium to large generating plant is a relatively large fraction of total capacity. Building such a plant solely for COM/Elec increases the reserve margin above what is desirable for reliability purposes. In order to avoid this problem, it is assumed that COM/Elec can buy or sell fractions of new units to effectively add capacity in smaller, more manageable amounts.

Figure 5.3 - COM/Elec Supply-Side Option Characteristics

	Fixed Ratio Technologies				*Fixed Size Technologies*		
	CT	**CC**	**IGCC**	**ALWR**	**Repowering**	**Canal 3**	**PV**
Characteristics							
Size (net new MW)	80	100	400	600	472 MW	609 MW	240 MW
Addition/Purch Size (MW)	80	100	100	150	By unit	By unit	2 kW
Fuel - Primary	Gas	Gas	Coal	Uranium	Gas	Coal	Solar
- Secondary	Oil2	Oil2	Oil6/Gas	n/a	Oil2	Oil6/Gas	n/a
(months fueled by spot/firm/kero)	(6/5/1)	(6/5/1)			(9/3)		
Heat Rate (BTU/kWh)	11146	8226	8806	10700	9033	11930	n/a
Capital Cost ('89$/kW)	442	627	1935	1807	375	5768	2500
Lead Times (Years)	4	4	6	6	3	By unit	1
First Year Available	1994	1994	1997	2002	n/a	2000	1995
Emissions (#/MMBTU)							
- SOx	0.0006	0.0006	0.18	0	0.0006	0.18	0
- NOx	0.036	0.036	0.04	0	0.036	0.04	0
- TSP	0.003	0.003	0	0	0.003	0	0
- CO2	115	115	202	0	115	202	0
- Spent Fuel (#/10E12 MMBTU)	0.00	0.00	0	34.48	0.00	0	0
Land Requirement (acres)	6	8	95	503	0	Old site	14/MW

Notes: 1) Technology Abbreviation Key: CT = Combustion Turbine, CC = Combined Cycle, IGCC = Integrated Gasification Combined Cycle, ALWR = Advanced Light Water Reactor, and PV = Phovoltaic.

2) Size and capital cost for Canal 3 are based on the net new MW on the site. Heat rate is average for the total 1711 MW

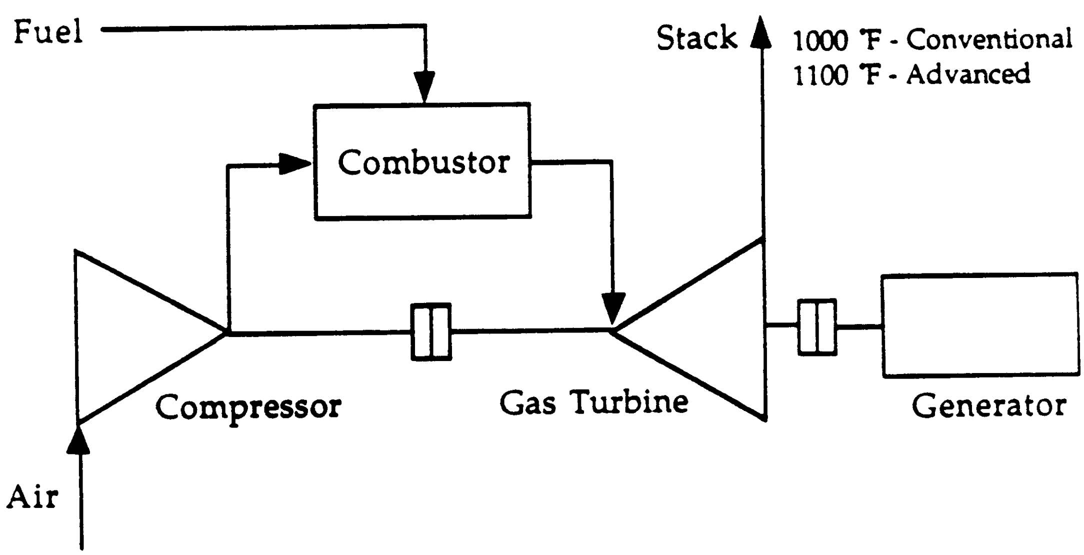
5.3 Supply-Side Option Technologies

Combustion Turbine (CT)

Natural gas or distillate (kerosene) fuel is mixed with compressed air and burned. The hot combustion exhaust gases drive a turbine generator for electric power.

Figure 5.4 - Combustion Turbine

Source: EPRI 1989 Technical Assessment Guide

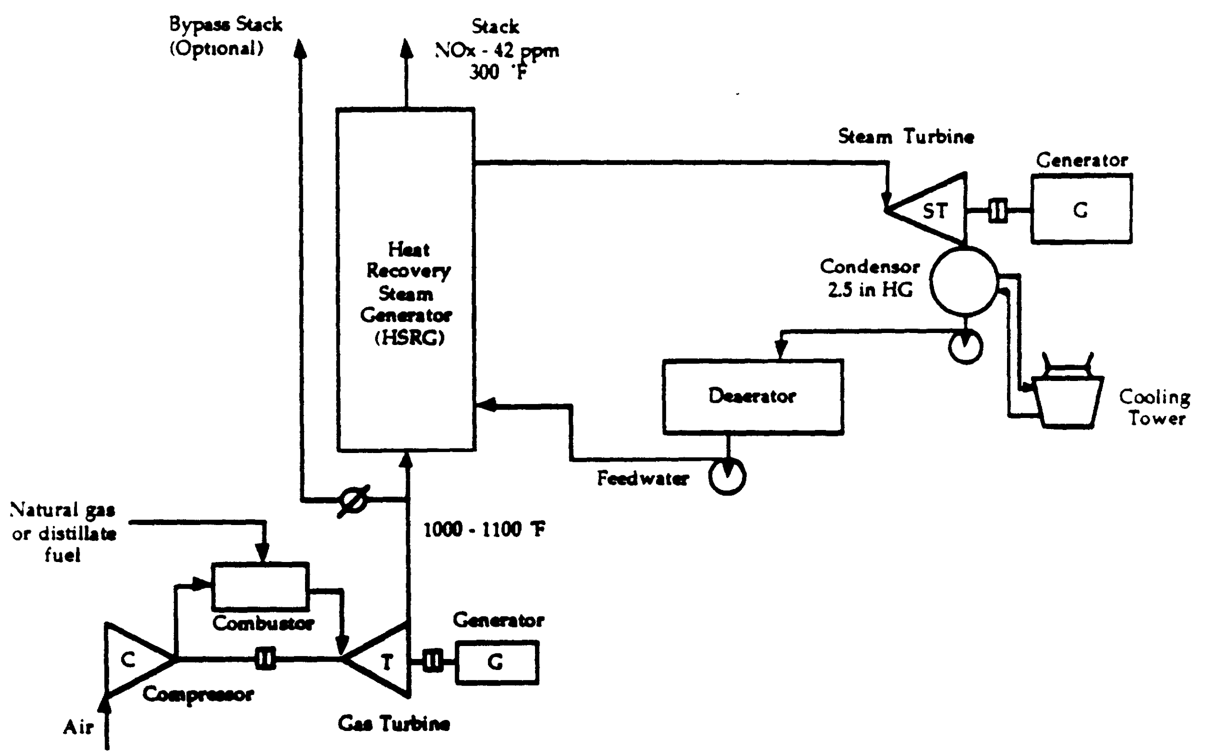


Combined Cycle (CC)

Natural gas or distillate (kerosene) fuel is used to fire a combustion turbine which generates power. Exhaust heat from the gas turbine boils water in a heat recovery steam generator, powering a steam turbine which drives a second electrical generator.

Figure 5.5 - Combined Cycle

Source: EPRI 1989 Technical Assessment Guide

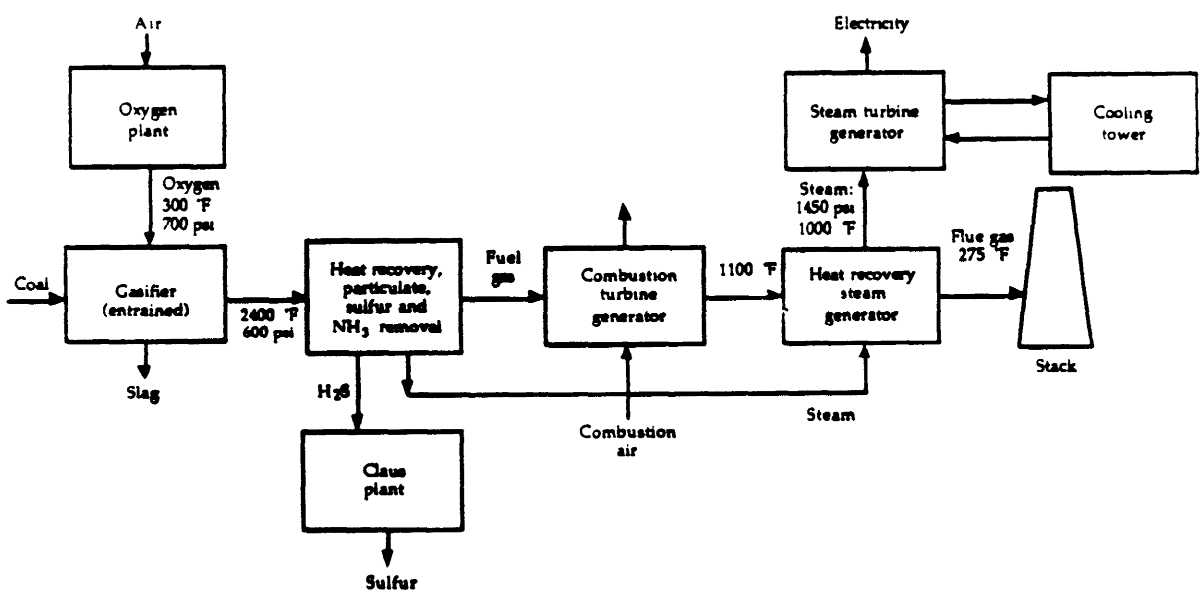


Coal Gasification Combined Cycle (CGCC)

Coal is gasified through a partial combustion process, and the cleaned synfuel gas is used to fire a combined cycle unit, as described above. Heat is recovered from both the gasification process and the combustion turbine in order to drive the steam turbine. Particulates and sulfur removed during the gasification process are sold as byproducts. These plants can be built in stages, building the combined cycle unit first, and adding the coal gasifier later. High sulfur coals can be burned very cleanly, and natural gas or distillate may also be burned if the gasifier is bypassed.

Figure 5.6 - Coal Gasification Combined Cycle

Source: EPRI 1989 Technical Assessment Guide

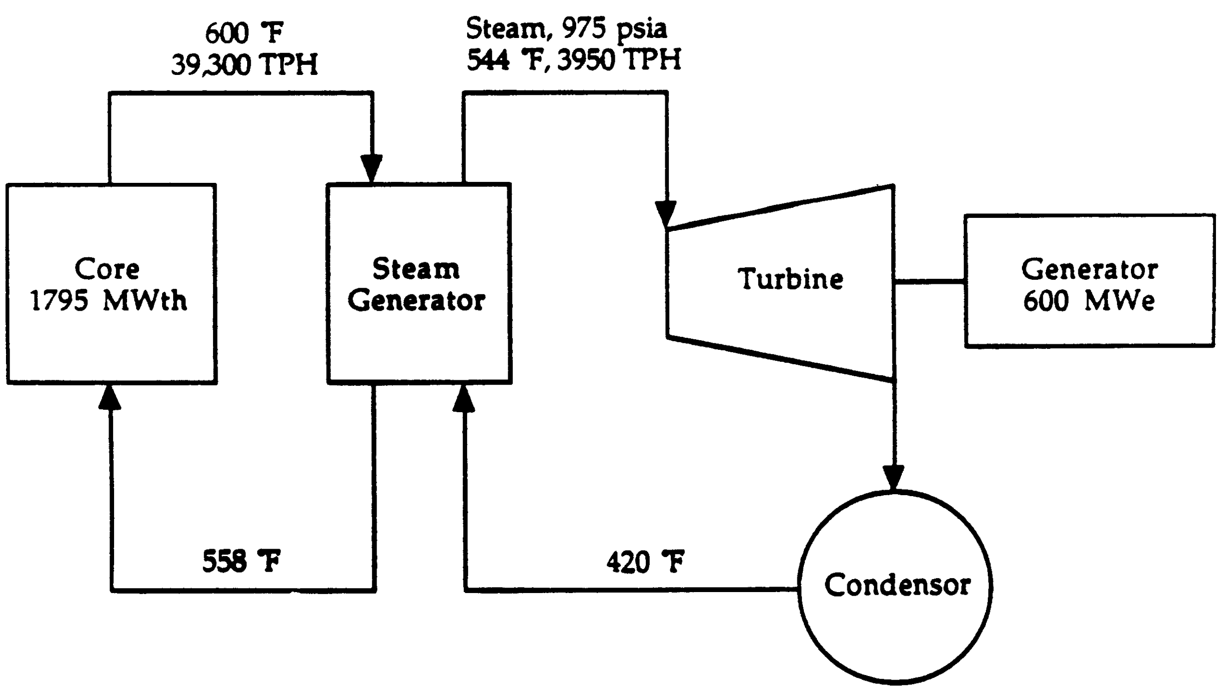


Passive Safety Advanced Light Water Reactor (ALWR)

As in a conventional light water reactor, heat is generated in the reactor's core and used to boil water for steam, either directly or through an intermediate pressurized water heat exchanger loop. Unlike current designs, the reactor is designed to cool itself without active operator intervention in the event of an accident. Standardized design and smaller unit size are aimed at increasing acceptance and reducing construction time.

Figure 5.7 - Advanced Light Water Reactor

Source: EPRI 1989 Technical Assessment Guide

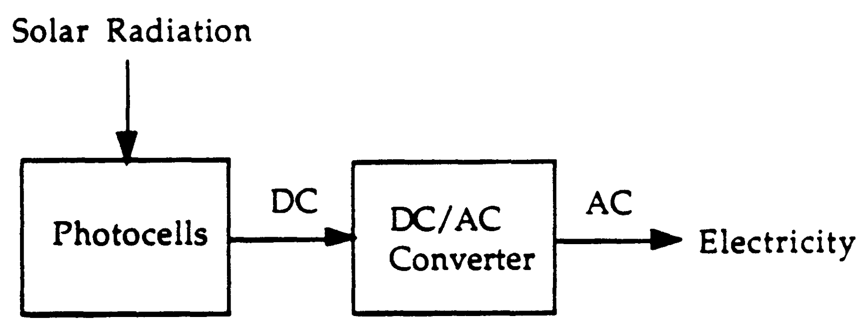


Photovoltaics (PV)

Photovoltaics convert sunlight directly to electricity using a photovoltaic semiconductor cell. The direct current electricity is then converted to alternating current for distribution and use. Electricity generated is not stored, and depends on season, weather, and time-of-day. Advanced materials and cell designs are aimed at increasing efficiency, and advanced materials and manufacturing techniques are aimed at reducing costs.

Figure 5.8 - Photovoltaic Cells

Source: EPRI 1989 Technical Assessment Guide



5.4 Supply-Side Option-Sets

The supply-side technology options above were combined into sets, and these supply-side option-sets, A through P, are shown below in Figure 5.9 - COM/Elec Supply-Side Option-Sets, which summarizes their composition from various fixed size and fixed ratio supply technology options.

Figure 5.9 - COM/Elec Supply-Side Option-Sets

SUPPLY-SIDE OPTION-SETS (High, Low Sulfur Oil)		TECHNOLOGIES *Fixed Ratio Options*				*Fixed Size Options*		
		CT	CC	IGCC	ALWR	Repowering	Canal 3	PV
A, B	- Gas Dependent	20%	80%					
C, D	- Repowering	40%	60%			472 MW		
E, K	- Gas & Coal	20%	40%	40%				
F, L	- Coal Dependent	20%		80%				
G, M	- Coal & Repowering	40%		60%		472 MW		
H, N	- Canal 3 & Gas	40%	60%				614 MW	
I, O	- Nuclear & Gas	20%	20%		60%			
J, P	- Photovoltaic & Gas	20%	80%					240 MW

Notes:

1) Technology Abbreviation Key: CT = Combustion Turbine, CC = Combined Cycle, IGCC = Integrated Gasification Combined Cycle, ALWR = Advanced Light Water Reactor, and PV = Phovoltaic.

2) All option sets include 50 MW new cogeneration, life extension for Canal 1 & 2, and all existing power purchase and cogeneration commitme

Each of the supply-side option-sets is described below, giving the rationale for the option-set design. The primary characteristic of the technology dominating each option-set is its fuel. In addition to option-sets depending on only a single fuel for new capacity, there are option-sets which represent a blend of these extreme cases. Thus, the Gas Dependent, Repowering and Coal Dependent options have base load capacity which is either all gas or all coal. The Gas & Coal, Coal & Repowering, and Canal 3 & Gas option-sets blend these "pure-plays" together. The Nuclear & Gas and Photovoltaic & Gas option-sets also represent blended strategies, because the dominant technology is limited by either the date or size available.

The target ratios for each option-set are based on three considerations - 1) the desired fuel blend discussed above, 2) the need for peak vs. base load capacity, and 3) the size of the fixed size option (if any). Based on the current mix of units in the COM/Elec system, base load and must-run capacity accounts for about 76% of total MW (nuclear, cogeneration, hydro and the Canal plant total 708 MW). The remaining 24% (225 MW) are predominantly peaking units, of which 18% are scheduled to retire (Blackstone, Cannon, and Kendall total 163 MW). To preserve this peak to base load ratio, roughly 20% of future capacity additions were chosen to be combustion turbines (CT's). This minimum target ratio for combustion turbines was increased when fixed size, base load units accounted for a large percentage of new capacity required.

Each description is for both of the two option-sets listed (e.g. A & B), which are identical in their technological mix, except that the second set substitutes low 0.5% sulfur Oil 6 fuel for the normal 2.2% sulfur Oil 6 fuel at the Canal plant.

Supply-Side Option-Sets A & B - Gas Dependent

These option-sets were designed to study the impact of greatly increased dependence on gas fired generation by making 80% of new capacity combined cycle units for base to intermediate loading, and 20% combustion turbines for peaking capacity. COM/Elec does not currently have any gas fired generation, except for cogenerators, and all of its combustion turbines currently burn kerosene or distillate Both of the technologies added under these option-sets are assumed to burn spot gas for 6 summer months, firm gas for 5 winter months, and kerosene for 1 winter month.

These option-sets do not distinguish between utility owned and non-utility owned capacity, and do not limit the amount of gas available in the region (a low-availability, high price uncertainty is discussed under fuel prices in the uncertainty section below). These option-sets do allow us to study the impact on emissions because natural gas burns very cleanly and has the lowest CO_2 content of any fossil fuel. These technologies are low relative capital cost, high fuel price options that allow the study of total cost impacts and sensitivity to fuel prices changes.

Supply-Side Option-Sets C & D - Repowering

These option-sets explore the possibility of repowering the existing Blackstone, Cannon, and Kendall sites by adding capacity at each site. All three plants retire in all option-sets, but in the Repowering option-sets these units come back on line in two to three years as larger units in rporating new technology. Specifically, the repowered units would include;

• Blackstone - The two existing boilers would be updated and a new turbine generator retrofitted. The plant would increase in capacity from 21 to 35 MW and come back on-line in 1996.

• Cannon - Two combustion turbines and two heat recovery steam generators would be added to drive the existing steam turbines, essentially turning the plant into a combined cycle unit. The plant would increase in capacity from 61 to 215 MW and come back on-line in 2001.

- Kendall - As with Cannon, two combustion turbines and a heat recovery steam generator would be added to drive the existing steam turbines. One of the existing steam boilers would be retained to make up the balance of the steam required and to supply the existing thermal steam load. This conversion would again in effect create a combined cycle unit that increases total electrical capacity from 66 to 222 MW, and comes back on-line in 2005.

The three units combined provide a fixed-size option of 472 MW. Additional new capacity required would be composed 40% combustion turbines and 60% combined cycle units. It is assumed that the repowered sites would be intermediate to base load units (like the other combined cycle units), so the relative fraction of combustion turbines in the variable size options was increased from 20% to 40% to provide sufficient peaking capacity.

These options-sets are also gas dependent, since it is assumed that the repowered sites will also burn natural gas in their combustion turbines. This natural gas is assumed to be a mixture of 9 months spot and 3 months firm. Oil would still be burned in the Blackstone and Kendall steam boilers, but these are comparatively very small. As a result, these option-sets should resemble Option-Sets A & B in their emissions performance.

The capital cost for these options is relatively low for both the repowered sites ($375/kW) and for the combustion turbine and combined cycle units ($442/kW and $627/kW respectively). Repowering is less expensive because it is assumed that capacity can be added to an existing site without major structural changes, thereby avoiding clearing the site and erecting new buildings.

These option-sets were based on previous COM/Elec studies done for the Blackstone and Cannon sites, and on conversations with COM/Elec planners (Mr. Paul Krawczyk) and engineers (Mr. Dave Wilson). The Repowering option-sets were evaluated as a "what if" option to see what benefits might actually be available.

In reality, there are a number of unresolved issues that could be problematic. Site licensing and opposition for these urban sites, and how they would compare to obtaining new site licenses, are unknown. The availability of sufficient natural gas at the sites may be a problem if no large pipelines run nearby. Environmental opposition may occur due to perceived emissions, but may be more easily satisfied, since these units would be very clean. Thermal emissions would increase, but the additional combustion turbine heat rejection would be up the stack with the exhaust and would not increase cooling water requirements.

Supply-Side Option-Sets E & K - Gas & Coal

These option-sets are a combination of the Gas Dependent and Coal Dependent option-sets. The intermediate/base load units are split into 40% combined cycle and 40% coal gasification combined cycle units, while the 20% of combustion turbine units for peak load is held constant. Results are expected to be intermediate of those for set A and F, especially for CO_2 emissions and fuel price sensitivity. For further discussion of assumptions and expectations, please see the sections on the Gas Dependent and Coal Dependent option-sets above and below.

Supply-Side Option-Sets F & L - Coal Dependent

These option-sets explored the use of clean coal technology to reduce SO_2 emissions and reduce the effects of fuel prices and fuel price volatility. Required new capacity is targeted to be 80% integrated gasification combined cycle units (IGCC), also called coal gasification combined cycle (CGCC) units. The remaining 20% of needed capacity was chosen to be combustion turbine (CT) units to meet peak loads. Initial runs for the COM/Elec internal advisory group split this coal capacity equally between IGCC and atmospheric bed fluidized combustion (AFBC) units.

However, because AFBC had no advantage in emissions and a slightly higher cost, it option was dropped from the final set of scenarios modeled.

These option-sets contrast with the gas dependent option-sets in that they have relatively high capital costs, lower fuel costs, and are much less sensitive to fuel price variations. It also has low air emissions, *except for CO_2*, due to the high carbon content of the coal fuel, which highlights the SO_2 vs. CO_2 tradeoffs.

Supply-Side Option-Sets G & M - Coal & Repowering

These option-sets are a combination of the Coal Dependent and Repowering option-sets. The intermediate/base load units are split into the 472 MW fixed size repowering option and the integrated gasification combined cycle option which makes up 60% of remaining required capacity. As before with repowering, the combustion turbine peak load contribution was increased from 20% to 40% of the required variable size option capacity, due to its reduction by the fixed size option contribution. Results are expected to be intermediate of those for the Coal Dependent and Repowering option-sets. For further discussion of assumptions and expectations, please see the sections on the Coal Dependent and Repowering option-sets above and below.

Supply-Side Option-Sets H & N - Canal 3 & Gas

The present Canal plant is made up of both the Canal 1 and Canal 2 units, sited on the Cape Cod canal. These option-sets investigated the possibility of replacing the 2.2% sulfur Oil 6 burned by both units with synthetic medium-Btu gas made from coal and also adding two coal-syngas fired units to the Canal site. Beyond the addition of this fixed capacity, further capacity is chosen to be 40% combustion turbines and 60% combined cycle units, similar to the Repowering option-sets.

These option-sets are based upon a design for an Integrated Gasification Combined Cycle (IGCC) unit done for the Electric Power Research Institute, where coal is gasified to burn in a combustion turbine, and waste heat drives a smaller steam turbine.

Based on the size and heat flows of this unit, it was determined that 4 similar coal gasification units would be required to supply the present Canal units 1 and 2 with the same heat input as the oil currently burned. The waste heat from the 4 gasifiers is used to generate 110 MW from a steam turbine, which offsets half the 220 MW required to separate oxygen from air for the gasification process.

In order to provide new net capacity, two new, complete IGCC units of the same design were included, providing 732 MW of power. The refueled Canal 1 and 2 units and the two new IGCC units would come on-line sequentially between 2000 and 2009, for a new total capacity of 1746 MW. Total cost is 3.51 billion 1989 dollars, or or 2013 $/kW of both old and new capacity. Total coal consumption would be 19,566 tons per day, with a net plant heat rate of 11,930 Btu/kWh. This heat rate is high, because the four gasifiers which fuel the existing Canal 1 & 2 units do not have the same efficiency as an integrated combined cycle unit, which recycles more of the heat flows.

As with an IGCC alone, the plant is environmentally very clean with regard to SO_2, NOx and particulates. High sulfur coal may be burned because the sulfur is reclaimed and sold for a market credit. Coal ash is also reclaimed and sold. However, there is a net increase in CO_2 emissions due to the higher carbon content of coal and the poorer heat rate.

This option was studied for its possible benefits, without consideration of certain site limitations. Although the Canal site is excellent for receiving coal and cooling water, it is likely that site size and the availability of fresh water would be constraints.

Supply-Side Option-Sets I & O - Nuclear & Gas

These option-sets were added because the external consumer advisory group felt that it should not be disregarded, despite public opposition. Even more than coal, this is a capital intensive option with low fuel costs and very low air emissions. Unlike coal, this technology has zero CO_2 emissions - the chief source of possible renewed public support - and the risks of safe operation and waste disposal. Because nuclear is a base load option, it was chosen to make up 60% of required new capacity, with 20% combined cycle units for intermediate load, and 20% combustion turbine units for peak loads.

The nuclear technology chosen for this option-set was the Advanced Light Water Reactor (ALWR). The smaller size, reduced lead time, and lower capital cost are based on EPRI assumptions, which are subject to some uncertainty. They compare very favorably to current designs, but such improvements were deemed realistic because they will have to be proven for a new generation of nuclear plants to have any chance at all of acceptance. The first year an ALWR could come on line was chosen to be the year 2000, so that nearer term requirements will have to be made up by the combined cycle unit component of this option-set (another reason for its 20% share).

Supply-Side Option-Sets J & P - Photovoltaic & Gas

These option-sets respond to the advisory groups' interest in the impact of renewable energy sources on the costs, reliability, and especially environmental characteristics of the electric power system. One of the most promising and well developed of these technologies is the photovoltaic (or solar) cell. Photovoltaic (PV) cells are semiconductor devices which convert sunlight directly into electricity.

Although this technology is currently too expensive for large scale application, it has significant potential for cost reductions. As of today, even the lowest-cost photovoltaic power systems cost about $5,000 per kilowatt of peak generating capacity (i.e. under full summer sun). This is several times the cost of many other generating technologies, but industry analysts believe that the cost for PV-generated electricity may be cut in half by the middle of this decade.

Although PV is a supply-side option, it was modeled in a fashion similar to the demand-side options because it modified the net electric load seen by the units that can be dispatched. We modeled a very optimistic scenario for PV, in which Commonwealth Electric underwrites the cost of installing a photovoltaic power plant on the roofs of half of the single-family residences in its southeastern Massachusetts service area. By the year 2005, this amounts to 108,000 homes, each with 20 square meters (about 214 square feet) of PV collector area. In addition, we modeled an area equal to about 20% of the commercial roofspace in Commonwealth Electric's service territory as being covered by photovoltaic cells (934,000 square meters). By 2005 then, the total PV collector area in service is just over 3 million square meters or about 763 acres. This investment takes place over the course of ten years starting in 1995, and is based on Commonwealth Electric's projections of single family residences and commercial floorspace.

By the year 2005, the photovoltaic power system we modeled is providing about 240 megawatts to supply the summer peak load. Assuming that the cost for PV does drop to $2,500 per kW, this amounts to an investment of almost $600 million in 1995 dollars (or about $470 million today, accounting for inflation). The system generates more than 6.3 billion kilowatt hours over the course of the study period. For purposes of comparison, the Collaborative process and Enhanced conservation programs (described later) save approximately 2.6 billion and 7.5 billion kilowatt hours respectively over the same time period.

Although PV could make a significant contribution toward meeting the peak summer load, the annual system peak load that Commonwealth Electric must plan for occurs in the winter after sundown. Because a PV system only generates when the sun shines, the system we modeled is incapable of contributing to this peak. Therefore, in addition to the PV system, new generating capacity must still be added which is identical to the amount required under the gas dependent strategies (A & B).

5.5 Planning and Operation Supply-Side Options

As initially mentioned, supply side option-sets may combine planning and operation, as well as new technologies for generating units. Two different non-technology options were explored in the final set of scenarios modeled. These were;

Target Reserve Margin

To explore the benefits on reliability of a higher reserve margin, new units were built to meet expected new net electrical load plus both COM/Elec's standard reserve margin of 22.8% ***and*** a higher reserve margin of 30%, for all the technology option-sets described above. The Fortran program that plans the number and date of new fixed-ratio units attempts to meet this target minimum reserve margin by commiting and canceling planned units as expected load growth fluctuates. New units generally have lower variable operating costs and are more reliable, so it is expected that this option-set will have the effect of offsetting higher initial capital costs with lower operating costs, while reaping the reliability benefits of more new units and higher overall capacity.

Under the higher reserve margin, option-sets that have fixed size units (such as the Repowering, Canal 3 & Gas, or Photovoltaic & Gas option-sets), will show a shift in results due to the relatively larger size of the total new fixed-ratio capacity built to meet the higher reserve margin. This will in effect dilute the benefits or problems due to the fixed size units.

Low vs. High Sulfur Oil 6

COM/Elec has no coal-fired units, so the majority of its SO_2 emissions come from the Canal plant, its only Oil 6 fired plant which currently burns 2.2% sulfur oil. In order to explore the effects on system costs and emissions of fueling this plant with lower sulfur oil, each combination of generating technology and reserve margin was also modeled with both Canal units 1 & 2 (totalling 435 MW) burning 0.5% sulfur oil at a slightly higher price. The benefits of this fuel substitution were very apparent in the set of 720 scenario model runs presented to the external, consumer advisory groups.

5.6 Demand-Side Options

As discussed above in Chapter 4, the number of demand side options was reduced from four to two in the final set of scenarios investigated for the external advisory groups. Both the No DSM and the Technical Potential option-sets were eliminated in order to keep the number of modeling runs manageable and because neither of these option-sets realistically represented a path that Commonwealth Electric would pursue. The remaining Collaborative Process and Enhanced Collaborative option-sets are are summarized in Figures 5.10 through 5.13, and are described below.

Figure 5.10 - COM/Elec Demand-Side Option-Sets
Collaborative and Enhanced Collaborative Programs

Targeted End-Uses

Customer Class	*Existing End-Use/Demand*	*Future End-Use/Demand*	*Market Development*
Residential	Electric Space Heating Program Hot Water/General Use Program Cambridge Energy Fitness Program Multi-Family Electric Efficiency Public Housing Efficiency Investment Energy Efficient Lighting	New Residential Construction Energy Efficient Lighting	Appliance Labeling Program
Commercial	Energy Efficiency Program for Existing Commercial Customers Schools Efficiency Renovation Energy Efficiency Program for Non-Profit Buildings	Architect and Engineer Liason Program	
Industrial	Energy Efficiency Program for Existing Industrial Customers Efficient Motor Rebate Program	Energy Efficiency Program for Industrial New Construction	

Figure 5.11 - COM/Elec DSM Option-Set Characteristics

Program Name End Use	Per Customer Investment	Annual kWh Savings	Total Number of Participants
Residential Programs			
Electric Heat Program			
Hot Water Measures	40	500	5000
Lighting Measures	50	250	5000
Heating Measures	1045	1650	5000
Air Conditioning Measures	10	100	3150
Hot Water/General Use Program			
Hot Water Measures	40	360	20050
Energy Management Training	0	100	16600
Lighting Measures	50	200	30500
Multi-Family Electric Efficiency Program			
Hot Water Measures	40	300	840
Energy Management Training	0	200	3100
Lighting Measures	50	250	4200
Heating Measures	850	1500	1500
Air Conditioning Measures	10	50	1034
Public Housing Efficiency Investment Program			
Hot Water Measures	40	300	1022
Lighting Measures	50	200	5700
Heating Measures	750	750	750
Energy Efficient Lighting Program			
Catalogue Sales	22	200	28080
Retail Sales	11.25	115	13750
Cambridge Energy Fitness Program			
Hot Water Measures	40	500	500
Energy Management Training	0	100	7000
Lighting Measures	50	300	10000
Air Conditioning Measures	10	100	3500
Appliance Labeling Program			
Refrigerators	45	105	6725
Freezers	45	100	1050
Room Air Conditioners	45	40	3275
New Residential Construction Program			
Heating Measures	1500	2800	1400
Other End-Uses (unspecified)	150	400	420
Commercial & Industrial Programs			
Commercial Retrofit Program†			
Small Buildings	1903642	8187297	5
Large Buildings	634390	5311022	5
Industrial Retrofit Program†	449200	2579555	5
School Efficiency Renovation Program†	1026878	4454570	5
Architecht and Engineer Liaison Program	64100	208800	200

† Program participation rates were unspecified, so all costs and savings were attributed to a single participant in each year of program operation.

Figure 5.12 - Peak Impacts of DSM Option-Sets

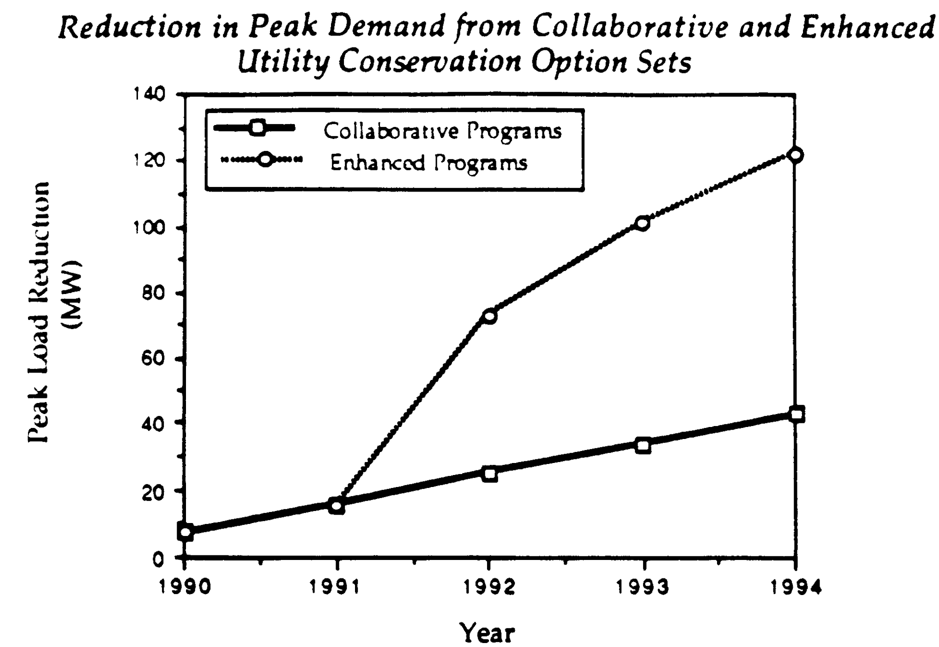
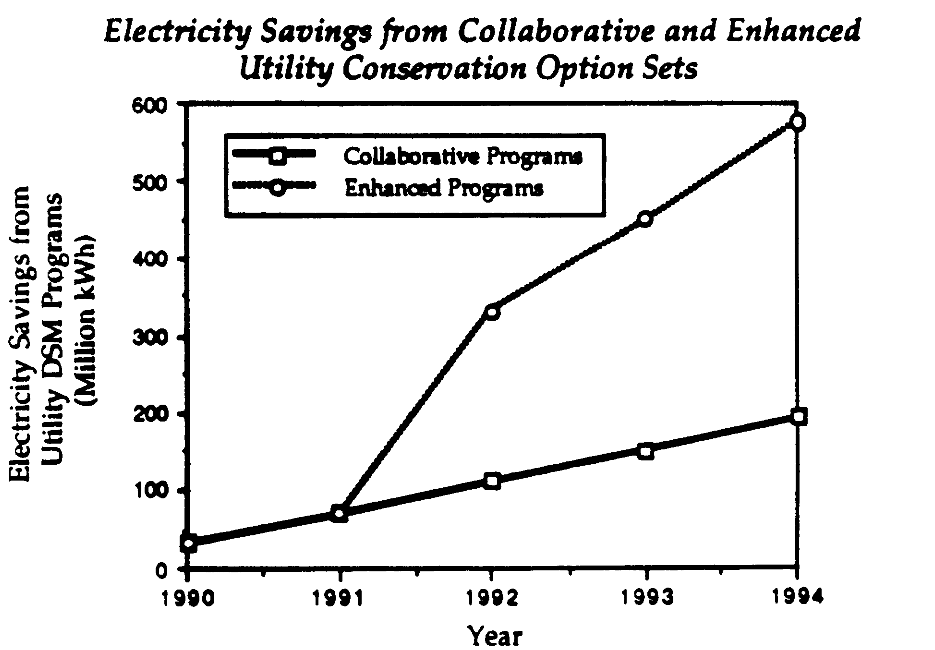


Figure 5.13 - Energy Impacts of DSM Option-Sets



Collaborative Process Programs

This option-set reflects the programs developed through Commonwealth Electric's participation in the Collaborative Process with the Conservation Law Foundation and a number of other Massachusetts electric utilities. These programs target every market sector served by Commonwealth Electric, and the reader is referred to the company's Massachusetts State Collaborative Phase II report of October 1989 (or a more recent version) for detailed program descriptions. All data entered into the model came directly from an August 1, 1989 draft of that report. As LMSTM models DSM programs on an end-use basis, the kWh savings and costs of each Collaborative program had to be disaggregated into multiple end-uses. For example, the Hot Water General Use program addresses water heating, air conditioning, appliance efficiency, lighting, and consumer energy management. The LMSTM input file therefore represents this program with five technologies, each with its own savings and cost figures, as well as appropriate load shapes and participation rates. Many of the programs address multiple end-uses in this way, and measures targeted at a given end-use, say lighting, may be a component of more than one program. While the draft report concerns itself chiefly with the total costs and savings expected for each program, it does contain estimates of expected measure costs and energy savings for each end-use. These are the figures used in the model. Penetration rates for each end-use technology also come directly from the draft report.

Each end-use measure has an effective energy-saving lifetime associated with it. For the majority of measures, this lifetime is shorter than our 25 year study period. As a result, most measures installed during the planned five year duration of the programs will have ceased to provide energy savings by the end of the study period. Replacement-in-kind is assumed due to a maturation in the market towards energy-conserving equipment aided by increasingly stringent appliance efficiency standards. These effects were already included in the demand forecasts provided by Commonwealth Electric and are thus accounted for. This demand-side strategy models only that conservation available to the company through its five-year investment in the Collaborative Process programs.

Enhanced Collaborative Programs

Early modeling work on the Technical Potential option-set (based on work by John Farley and an assessment of COM/Elec's technical potential by Xenergy Inc.) indicated that there was a sizeable gap between the energy savings available through the Collaborative Process programs and this theoretical maximum. Accordingly, the Enhanced Collaborative option-set was developed to investigate the behavior of the COM/Elec system under a level of DSM investment designed to tap a greater fraction of this potential.

Under this option-set, the penetration of each of the Collaborative Process programs is tripled after a two year delay to allow for program "ramp-up". In increasing the participation rates in these programs, the utility would be likely to face diminishing returns, so that the investment required to triple program impacts would be more than three times the investment required under the original programs. To account for diminishing returns, the costs for these additional participants were escalated by 20 percent. Energy savings per-participant remain constant.

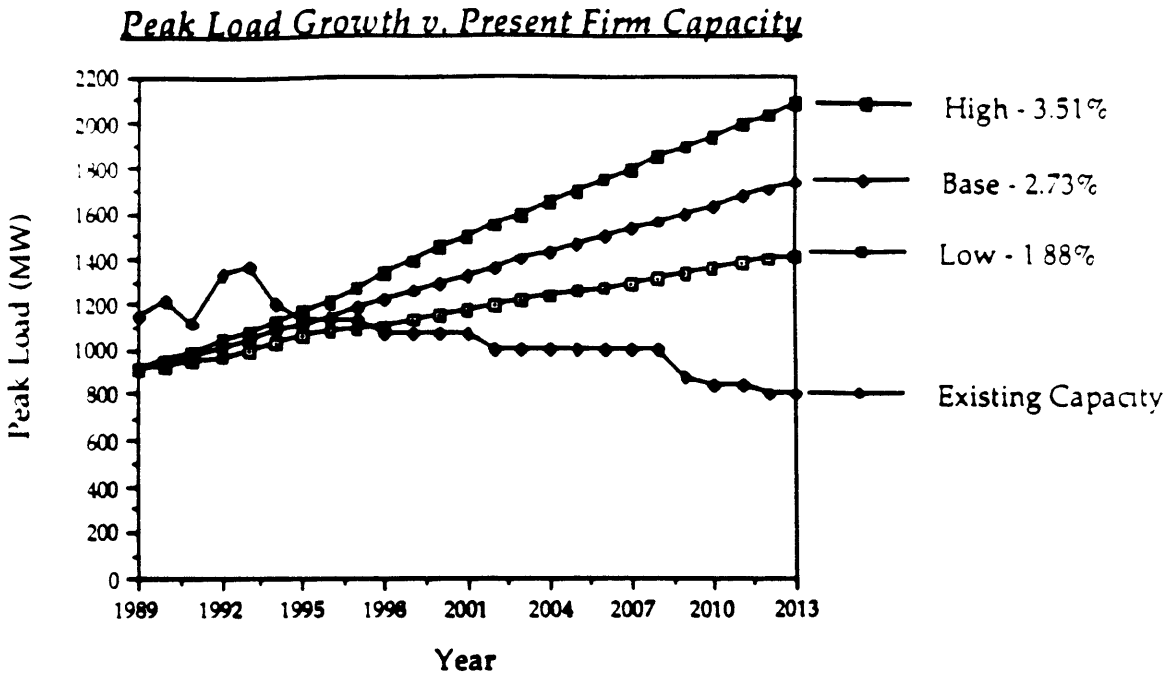
5.7 Uncertainties

The predominant uncertainties identified by the four consumer advisory groups were broken down into four general areas: Load/Economic Growth, Fuel Prices, Customer Response to Demand-Side Management Programs and Changes in Interest Rates.

Load/Economic Growth

Projected peak electric load growth was obtained from the COM/Elec planning department, including market driven DSM responses. The low, base, and high load trajectories were then adjusted for either the base case collaborative or enhanced DSM option-sets. The curves shown shown below in Figure 5.14 include the savings from the collaborative process DSM measures with expected customer responsiveness to DSM. Although the collaborative process savings are significant, they do not shift the load curves very much relative to the absolute magnitudes of the No-DSM growths projected. For comparison, Figure 5.14 also shows COM/Elec's current trajectory of existing and firm future capacity. New capacity construction is necessary to fill the gap between the capacity and net load trajectories, *plus* the reserve margin.

Figure 5.14 - COM/Elec Load Growth Trajectories



Fuel Prices

Fuel prices are a key uncertainty, especially relative to each other as they affect the dispatch and loading order of generating units, and hence environmental emissions, costs, and other attributes. This uncertainty studied the effect of base and restricted natural gas availability, reflected as base and higher natural gas prices respectively, relative to base fuel prices for other fuels. This choice of uncertainty was prompted by the desire to study the effects of natural gas availability relative to other fuels with stable availability and prices. In order to determine a reasonable high gas price trajectory for futures with low gas availability, the MIT analysis team looked at the high prices forecast for all fuels by Data Resources, Inc. (DRI). The spread between DRI's natural gas and oil prices did not appear reasonable for the high growth fuel price forecast when compared to DRI's other low and base fuel price forecasts. These high forecast fuel prices are shown in Figure 5.15, with all fuel prices in current $/MMBtu, and in Figure 5.16 with all fuel prices shown as ratios relative to the price of 2.2% sulfur Oil 6. As shown in these figures, the prices of natural gas forecast by DRI are significantly lower than the prices for oil 6, and especially for diesel and kerosene, to such an extent that seems unreasonable, given the substitutability of gas for these fuels.

Figure 5.15 - DRI High Fuel Price Forecast ($/MMBtu)

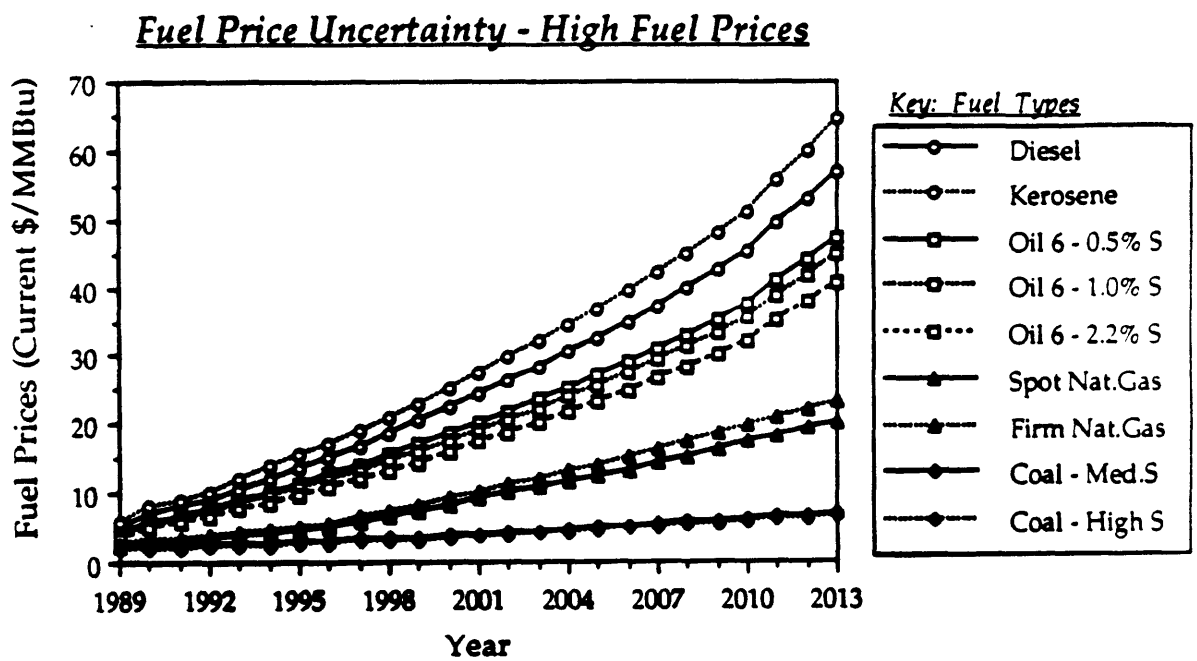
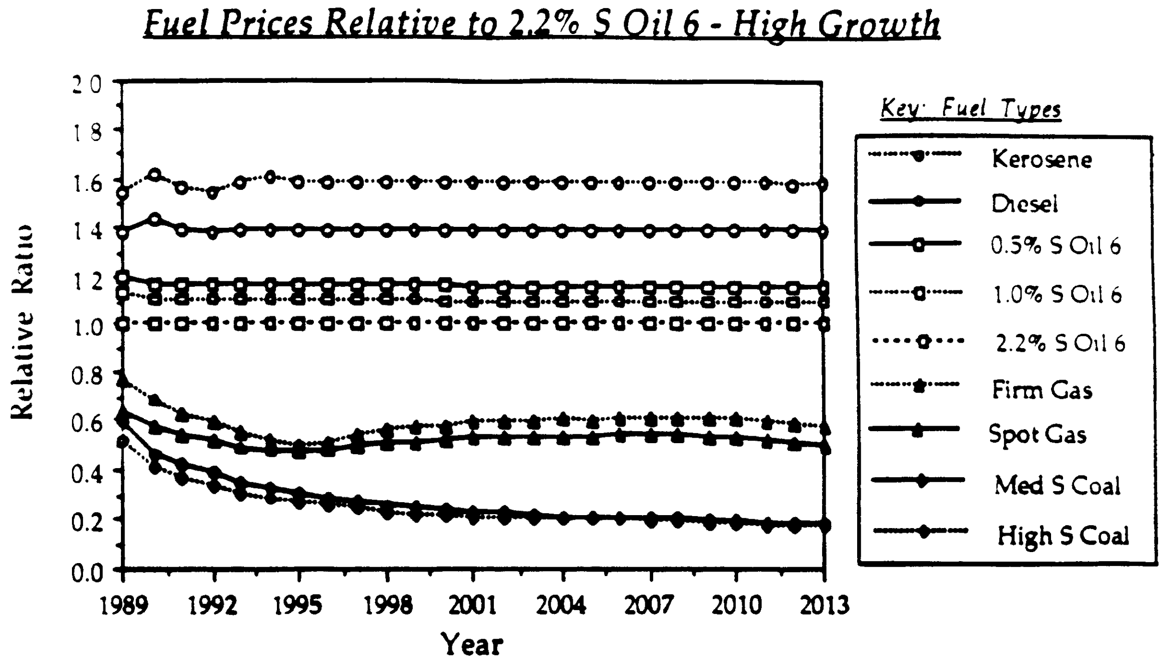
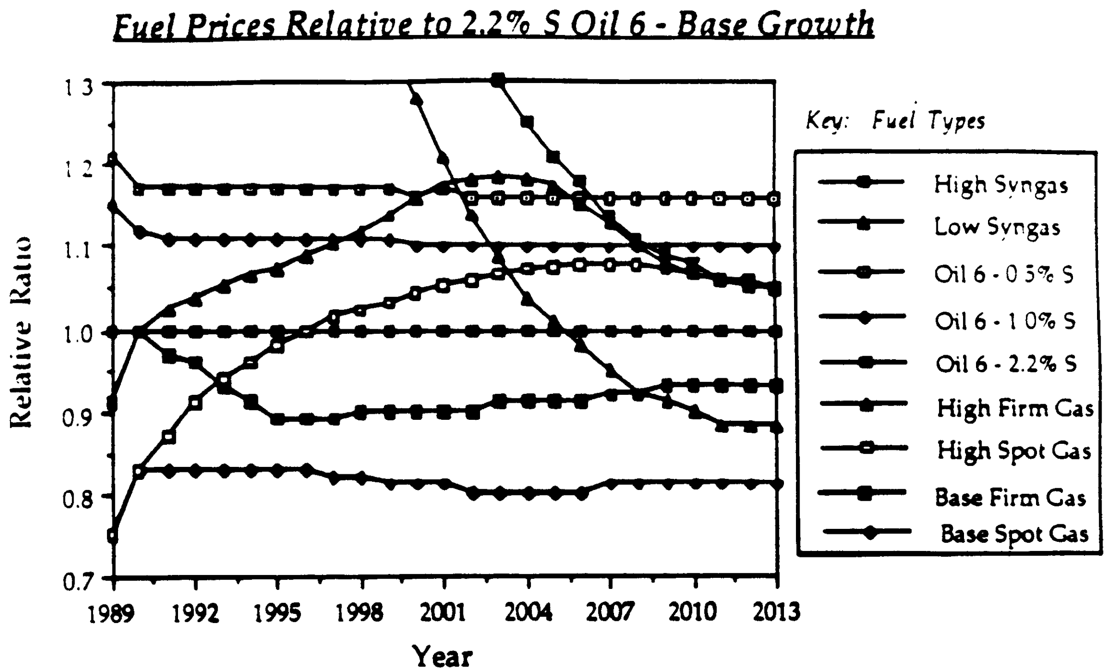


Figure 5.16 - DRI High Fuel Prices Forecast Relative to Oil 6



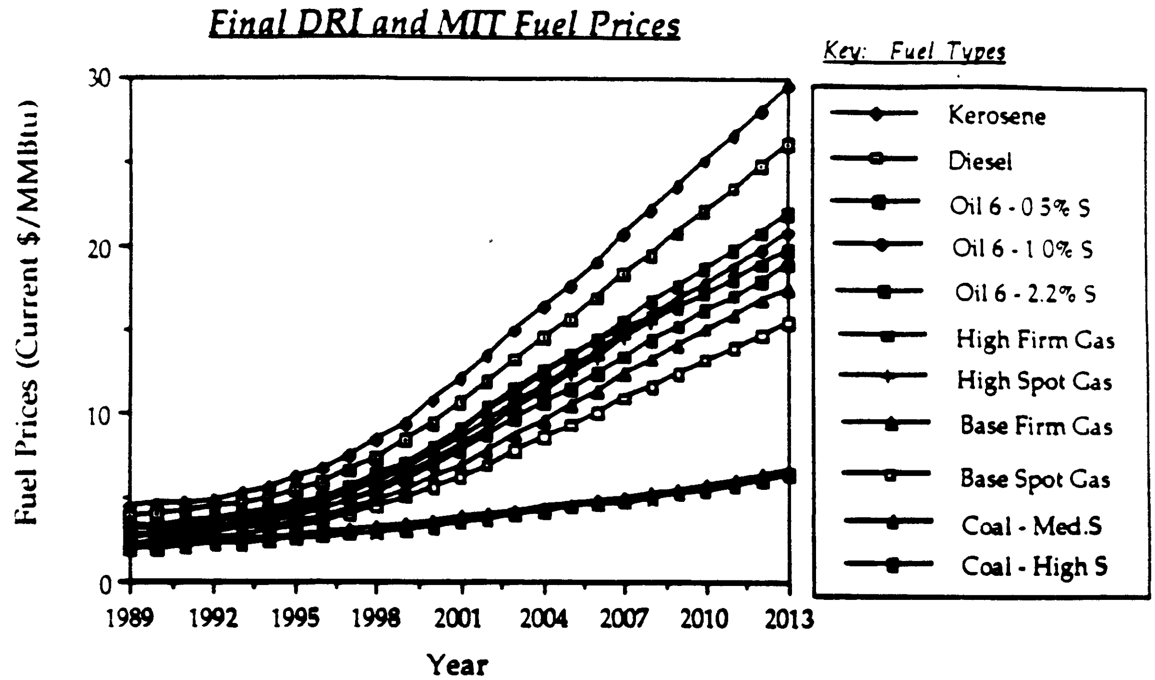
For this reason, the MIT analysis team posited their own high natural gas price trajectory shown in Figure 5.17. In this figure, the price of natural gas rises relative to the base oil price, but then is bounded from above by the dropping price of synthetic gas produced from coal. This upper bound was based on an EPRI estimate that syngas would be competitive now at $5 to $6 per MMBtu (1989 EPRI Technical Assessment Guide, page 7-47). This price was escalated based on the similar rates for coal gasification capital costs and coal prices. Both capital costs and coal prices rise more slowly than oil prices, so the relative price of syngas falls. Both syngas fuel price trajectories are shown in Figure 5.17, and the analysis team made the conservative choice that the $6 syngas fuel price trajectory would serve as an upper limit to the high natural gas prices.

Figure 5.17 - MIT High Natural Gas Price Trajectory Relative to Oil



Based on this reasoning, the final set of fuel prices were established as shown in Figure 5.18. DRI's base forecast fuel prices were used for all fuels, except that the MIT natural gas price determined as above was used for the high spot and firm natural gas prices.

Figure 5.18- Fuel Prices Used in Model Scenarios



As shown, gas prices were estimated for both firm and spot natural gas. Units burning natural gas were assumed to burn spot gas for 6 summer months, firm gas for 5 winter months, and distillate or kerosene for the remaining 1 winter month. This fuel substitution was achieved in the model by splitting each unit into three, each with a different fuel and complementary maintenance schedules.

No assumptions were made about the actual amount of natural gas or pipeline capacity available. The high gas price uncertainty is intended to reflect the supply and demand cost impact of such a constraint. The results for the amount of gas burned in both cases should be compared to COM/Elec's estimates of gas available for the region.

Customer Response to Utility Conservation Initiatives

As many of the conservation programs currently being implemented by Commonwealth Electric are untested, a high degree of uncertainty remains as to their energy-saving effectiveness. To bracket the probable range of energy savings that will actually result from these programs, the analysis team modeled three levels of conservation measure effectiveness: 1) conservation impacts as planned, 2) 50% more conservation than expected, and 3) 50% less conservation than expected. These multipliers were applied to the per-participant energy savings for each end use technology modeled in both the Collaborative and Enhanced Collaborative DSM option-sets. Per-participant costs remained unchanged.

5.8 Other Inputs

Emissions Data

In order to understand the environmental impacts of capacity construction and operation decisions in the scenarios studied, a number different environmental attributes were calculated. Air pollution emissions included sulfur dioxide (SO_2), nitrous oxides (NO_x), total suspended particulates (TSP), and carbon dioxide (CO_2). Because of the uncertain and value-laden process of calculating emissions transport and subsequent damage, emissions were reported as total tons emitted over the 25 year study period, rather than trying to assess their environmental damages. Similarly, nuclear waste was calculated as tons of spent fuel because of uncertainties in the (re)processing and disposal process. To measure land use impacts relevant to new site opposition, the number of new plants and acres required to site them were also calculated.

Air pollution data was unavailable on a plant specific basis, either from COM/Elec (except for ambient Canal data), or from the Massachusetts Division of Air Quality. As a result, both emissions and spent nuclear fuel were figured on the basis of fuel consumed, using the following equation for the calculation of plant specific emissions.

$$\underset{\text{(lbs)}}{\text{SO2 Emissions}} = \underset{\text{(kWh)}}{\text{Total Energy Produced}} \times \frac{\text{Fuel Input (Btu)}}{\text{Unit Energy (kWh)}} \times \frac{\text{Pollutant Content (lbs)}}{\text{Unit Fuel (Btu)}} \times \frac{\text{Emissions (lbs)}}{\text{Unit Pollutant (lbs)}}$$

In order to account for old vs. new units, and different technologies burning the same fuel, a number of new fuels were created with identical price trajectories but with technology or unit specific emissions data. For example, the units representing power purchase contracts burn a "fuel" that reflects the Northeast Utilities system mix of nuclear, oil, and kerosene consumption.

Emissions data for old, existing units were largely taken from the EPA Document AP-42. New unit pollution data was taken from technology specific sources and conversations with sources at COM/Elec, MIT, the Electric Power Research Institute (EPRI), and the Northeast States for Coordinated Air Use Management (NESCAUM). In general, the new technologies chosen were inherently low in emissions. No major additions or retrofits of pollution abatement equipment was made on existing units. New combustion turbines however are fitted with selective catalytic reduction (SCR) equipment, which reduces NO_x emissions by adding ammonia to the exhaust before passing it over a catalyst. For specific emissions rates, sources, and assumptions please refer to the emissions spreadsheet in Appendix A.

NEPOOL Operating Procedure 4 Action Capacities

When peak load exceeds generating capacity, there is a series of steps that are taken before customer outages become necessary. For the New England Power Pool (NEPOOL) these steps are codified as Operating Procedure 4 (OP-4) actions. In order to represent system reliability, these various actions were represented by modeling them as high cost generating units in LMSTM. By knowing the electricity "generated" by these OP-4 units and their size, the hours spent in each OP-4 Action level can be determined. This "virtual unit" method is the same way that LMSTM calculates unserved energy.

By examining NEPOOL documents and conversations with NEPOOL and COM/Elec personnel, the capacity of each action level was determined. These actions are defined and their size shown below in Figure 5.19. Actions 1 and 2 are grouped together, and vary between summer and winter due to the variation in seasonal unit capacities. Load curtailments in actions 8 and 9 were also grouped together. These OP-4 Actions and their related generation or load reduction capacity are graphed and shown in Figure 5.20, which shows only those actions mentioned above and omits all other OP-4 actions which contributed zero MW to reducing COM/Elec's peak load.

It was assumed that the OP-4 action levels would maintain their potential contribution as a constant fraction of COM/Elec's peak load. Each of the five "generating units" representing these actions was therefore assumed to grow in capacity at the same rate as total system load. Thus, different sets of OP-4 units were used depending on whether the load uncertainty in the scenario was low, base, or high growth. Because DSM measures have a relatively small fractional impact on total load, the OP-4 capacity trajectories were not adjusted for either DSM option. In order to make sure that these OP-4 units were dispatched last and in the correct order they were given very high variable O&M costs that increased as the OP-4 action became more severe. The cost of unserved energy was also increased, so that LMSTM's internal "unit" representing outages was dispatched last.

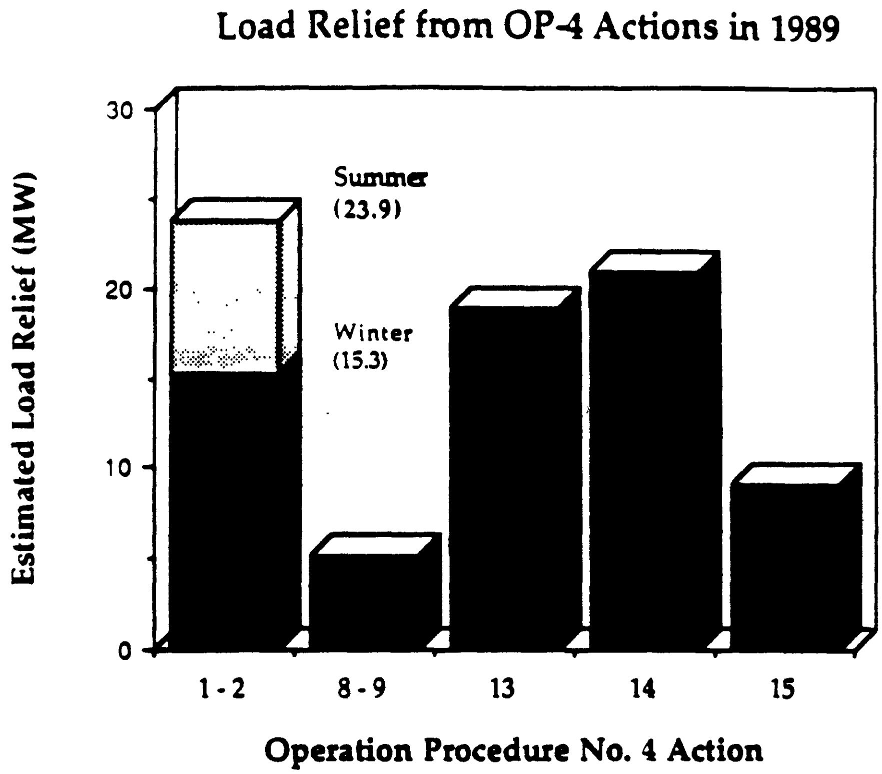
Figure 5.19 - OP-4 Action Definitions and Capacities

Operating Procedure 4 - Actions During a Capacity Deficiency

Estimates of Additional Generation and Load Relief

Action Number	1989 Capacity (MW) Summer	Winter	All Year	Description
1	6.00	14.62		Steam generation to max claimed capability.
2	9.25	9.25		All on-line internal combustion units to max claimed capability
3			.00	Curtail NEPOOL Block E dispatchable load.
4			.00	Curtail NEPOOL Block D dispatchable load.
5			.00	Curtail NEPOOL Block C dispatchable load.
6			.00	Purchase emergency capacity and/or energy.
7			.00	Curtail NEPOOL Block B dispatchable load.
8			4.10	Curtail NEPOOL Block A dispatchable load.
9			1.00	Voluntary load curtailment at NEPOOL participants' facilities
10			.00	Request customer generation contractually available.
			.00	Curtail NEPOOL special interruptible loads.
11			.00	Allow 30 minute reserve to go to zero.
12			.00	5% voltage reduction requiring more than 10 minutes.
13			19.00	5% voltage reduction requiring less than 10 minutes.
14			3.00	Request customer generation not contractually available.
			18.00	Request voluntary load curtailment by large customers.
15			9.00	Broadcast public appeals for voluntary load curtailment.

Figure 5.20 - OP-4 Action Level Capacities



Transmission and Distribution Assumptions

When DSM options are implemented, they not only save the construction of new generating capacity, but they also save the construction of new transmission and distribution (T&D) lines which would otherwise be required. Because of this, there should reasonably be a T&D cost/new kW charge that should either be subtracted as a credit from DSM costs, or added to the capital cost of new capacity. Unfortunately, this amount is very difficult to ascertain. By tracking past COM/Elec data on T&D investment and load growth, it was clear that T&D expenditures are much more closely correlated with system size than load growth. The net present value of additional T&D costs over the 30 year life of a plant required to meet new load were calculated and found to be $780/kW. For the NEPOOL region as a whole the ratios of T&D to production plant were found for both plant-in-service and net plant. This ratio suggested a cost multiplier of approximately 1.5 for new capacity capital costs. Both of these estimates were thought to be first approximations, and neither included the intangible costs of public opposition to new transmission, which may be as much or more than that to new power plants. As a result, the total costs calculated did not include either of these additional T&D costs. However, the certain existence and probable magnitude of these costs should not be ignored in interpreting the results presented by this project.

6.0 Results and Discussion

This chapter presents the results of analyzing the complete set of 1152 scenarios described in Chapter 5, as opposed to the results for 720 scenarios which were presented to the consumer advisory group and briefly described in Chapter 4. These results are presented using the following steps. First, a set of primary issue-oriented attributes are chosen for describing the most important results. All other attributes are relegated to secondary, supporting roles. Second, the overall range of variability for the primary attributes is examined, so that the relative impacts of the different uncertainties and strategies can be compared later. Based on this initial examination of variability some scenarios are then eliminated, so that trends in the reduced subset of results are more easily identified. Third, single attributes are interpreted, according to how they vary with respect to uncertainties, options-sets, and strategies. Fourth, pairs of attributes are considered using multi-attribute tradeoff curves showing the tradeoffs between the single attribute trends already identified.

The approach taken in presenting the impacts of different uncertainties and strategies loosely follows the analysis steps described in Chapter 3. While these steps help the analysis team interpret the results in a co~~nlete and consistent manner, presentation of the results in this chapter focuses on the communication of those results discovered through the use of that method, rather than presenting the analysis in step-by-step detail. This chapter identifies and interprets the chief trends and stories of the technical analysis. Chapter 7 then restates these findings, and integrates this information with those lessons learned by performing the analysis in an open planning context.

6.1 Identifying the Primary Attributes

The final results calculated include over sixty attributes for each of the 1152 scenarios modeled. Each of these attributes is defined in Appendix B, with units and method of calculation. However, to comprehend such a large number of results, it is necessary to divide them into the most important, primary attributes which tell the main stories, and the supporting, secondary attributes which explain the reasons behind the primary results. This division may be gradual, rather than clear cut and absolute. Nevertheless, the analysis team focused on a limited set of primary attributes, and only those secondary attributes necessary to explain them.

As identified by the external Consumer Advisory Group (see Table 4.6), the issues of primary concern identified were divided into four main areas; Cost of Electric Service, Environmental Quality, Efficiency of Electric Service Provision, and Reliability of Electricity Supplies. This section takes these four main areas and identifies the primary attributes picked for each area, explaining why these attributes were chosen and why others were relegated to secondary status.

Cost of Electric Service

The choice of attribute used to measure an issue can be key in determining the choice of strategy. This can be especially true in the area of cost, where different measures include total cost of service (discounted and non-discounted), the cost of investing in supply-side and demand-side resources, annual revenue requirements, the cost of electricity to the ratepayer, and the cost for electric services.

The analysis team chose as the primary attribute the average cost per unit of electrical service, or the average unit cost of service (UCS). This attribute was chosen for several reasons. First, it is a unit cost, and so is independent of the demand for electricity. Demand depends mostly on economic and population growth, neither of which are controlled by the utility, and total cost does not measure the cost to the individual consumer. Thus, results presented in this chapter are different from the initial results presented in Chapter 4, which show total cost vs. total emissions.

Second, this attribute measures the cost of service, whether that service (heat, light, etc.) is provided by building new generating capacity, or by installing conservation or load management measures which provide the same amount of service using less electricity. To do this, the real annual revenue requirements (adjusted for inflation and in 1989 dollars) are divided by the energy that would have been sold if no DSM measures had been implemented. Including the energy saved by increased DSM means that the unit of service includes service provided by both electricity and increased end-use efficiency.

The unit cost of service is essentially an adjusted cost of electricity, but it differs from the usual cost in an important way. DSM measures are included in the cost of electricity, but decrease the amount of electricity purchased. Thus the rate paid for electricity may increase while the total bill decreases. The unit cost of service tracks changes in the *total bill paid for a constant amount of service.*

The average cost of service results in this Chapter show trends for the bill of an *average* customer. The rate *and* the total bill will *increase* for customers who do not participate in DSM programs (thus failing the so-called "No Losers Test"). However, because DSM measures are cheaper than new sources of generation, the bill will increase *less* for those customers than it would if new capacity alone were added. Massachusetts state regulatory policy ensures that DSM programs are available to all customer classes, so that each customer has the opportunity to save.

While the cost of electrical service is important, it may also be important to customers that this price not fluctuate wildly or unexpectedly. Thus, the variability of the unit cost of service (or "rateshock") may also be considered as a primary attribute, particularly by large business customers for whom electricity is a significant cost, and therefore a significant factor in their planning decisions. This variability was measured both by the standard deviation of the annual unit cost of service, and the maximum annual increase in the unit cost of service. The analysis team chose to use the maximum annual increase of the UCS as the primary attribute for this concern.

Environmental Quality

In choosing attributes to measure environmental quality, the analysis team chose to concentrate on air pollution measures. This was because air pollution is the area of greatest environmental impact and public concern produced by production of electricity. The analysis team calculated attributes for the production of sulfur dioxide (SO_2), nitrous oxides (NO_x), total suspended particulates (TSP), and carbon dioxide (CO_2). These emissions were calculated as total number of tons produced over the 25 years of the study period. There are two relevant comments here. First, air quality depends not just on emissions, but also upon the atmospheric conversion and transport of pollutants. These processes are understood but difficult to quantify, so it was chosen to concentrate simply on emissions. Second, emissions were not discounted in the same way that costs were. That is, a ton of emissions in 25 years in the future counts for just as much as a ton next year (likewise, cumulative kWh energy totals over the study period were not discounted). The analysis team chose to do this, rather than to impute a discount rate for future health, environmental damages, or energy consumption.

Of the four emissions attributes, SO_2 and CO_2 were chosen as primary attributes, while NO_x and TSP were relegated to secondary status. This was done for two major reasons. First, SO_2 and CO_2 measure the two major issues of acid rain and global warming. SO_2 can be considered a regional problem, because acid rain precipitates downwind of the emissions site, while CO_2 emissions are a global problem, contributing to possible climate changes which are still statistically indeterminate.

Second, NO_x and TSP are both correlated with SO_2 emissions, so SO_2 can be considered a proxy attribute for NO_x and TSP emissions. This correlation depends upon whether low sulfur Oil 6 or high sulfur Oil 6 is burned, as shown in Table 6.1, which gives the Pearson correlation coefficients between pollutants. Where the correlation is statistically significant, the figures are given in bold type. This correlation occurs because the different kinds of emissions are linked to the operation of old, existing powerplants. The correlation is not perfect because of variation in these plants, and and because relative generation by these plants shifts under different scenarios. This correlation is also diluted by new construction to a degree that depends on total load growth, because all the new forms of generation considered were very clean in both NO_x and TSP emissions.

Table 6.1 - Correlations between Emissions

	Scenarios Burning Low Sulfur Oil 6				Scenarios Burning High Sulfur Oil 6			
	Sulfur Dioxide	Nitrous Oxides	Suspended Particulates	Carbon Dioxide	Sulfur Dioxide	Nitrous Oxides	Suspended Particulates	Carbon Dioxide
Sulfur Dioxide	1				1			
Nitrous Oxides	.972	1			.957	1		
Suspended Particulates	.628	.736	1		.906	.933	1	
Carbon Dioxide	.585	.547	0.364	1	.497	.556	0.417	1

Other measures of environmental quality include solid waste, land use (the number and MW of new plants, and the acres required by them) and spent fuel produced from nuclear plants. Solid waste is not a significant problem because the new coal technology considered (coal gasification combined cycle) gasifies the coal before combustion, and sell the ash and sulfur as byproducts. Land use measures were considered less important, or at least less easy to quantify, because public opposition (the "not in my back yard" or NIMBY problem) is very site specific, and the planning model used in the analysis does not specify geographic sites. Nuclear waste produced was also relegated to secondary status. This problem is linked more to waste from existing plants and the method of long-term disposal chosen than to new construction, and opposition to new construction will depend on many other factors beside just the issue of waste.

Efficiency of Providing Service

Measures of efficiency included fossil and system heat rates, and percent changes in supply, demand, and system efficiencies. All of these attributes were chosen to be secondary, supporting attributes. Efficiency has a strong and important effect on system operation, but it does this through reduced fuel consumption which in turn reduces the primary attributes of cost and emissions. Efficiency thus plays a supporting role and is mentioned in the rest of this chapter only when this supporting role in important in understanding the story underlying a primary attribute result.

Reliability of Electric Service

To measure the impact of reliability, the primary attribute was chosen to be the total number of hours spent in OP-4 Action 13 over the entire 25 year study period. This OP-4 Action corresponds to a 5% voltage reduction, which precedes requests for large consumers to voluntarily reduce consumption and maximize self generation (see Figure 5.19 for the definition and resource size of all OP-4 Action levels).

This measure of reliability was originally developed for the Open Planning Process to express reliability in a way that is more meaningful to customers than the traditional outage probability or energy deficit measures. This attribute is not discounted (an hour of voltage reduction is the same next year or 25 years hence), and ignores possible variations in amount of hours spent in lower OP-4 levels (interrupting customers with interruptible rates, etc.).

Because the Prespecified Pathway planning program (see Chapter 3, page 15) used to plan future unit additions uses a maximum percentage cap on the expected load growth rate for each year, there are a small number of years in most scenario capacity trajectories that have low reserve margins. These do not persist, so overall reliability results are meaningful, but very fine differences in OP-4 hours cannot be counted as significant trends.

6.2 Attribute Variability and Reduction of Data Set

The first step in analyzing the results is to look at the range and variability of the single attribute results for different uncertainties and option-sets. The analysis team did this, examining all the results using both single attribute box plots, and multi-attribute scatterplots. The result of this examination was that one group of results stood out from all the rest. The Canal 3 supply-side option-sets (supply-side option-sets H and N) were markedly higher in cost (15% higher average than the next most expensive photovoltaic option-set) and had no corresponding advantages in the other primary attributes for cost or reliability. The cause for this disadvantage was clear. As explained in Chapter 5, the Canal 3 option refuels two very efficient oil-fired units at the Canal site with synthetic gas made from coal. The refueled units do not have the efficiency of combined cycle operation, and are very expensive due both to high capital costs and a poor heat rate.

Based on these observations, the results for all the Canal 3 option-set scenarios were removed from the final data set before further analysis. This was done for two reasons. First, the Canal-3 option-set would clearly be rejected in any analysis because it is dominated by other strategies. Second, and more important, keeping (and ignoring) the Canal 3 results would obscure the spread in results for more competitive strategies. Including the Canal 3 results requires the graph scale to be compressed to show these very high values. Eliminating the Canal 3 results allows the scale to expand and show the relative differences of the remaining options more clearly. This effect is shown in Figures 6.1 and 6.2 below. In reading this type of graph throughout the rest of the chapter, the minimum value is actually the border between the blank and dark-hatched blocks in each column, the mean value is actually the border between the light-hatched and dark-hatched blocks, and the maximum value is the top border of the light-hatched block.

Figure 6.1 - Average Unit Cost of Service by Supply-Option Set

(Canal 3 Results Included)

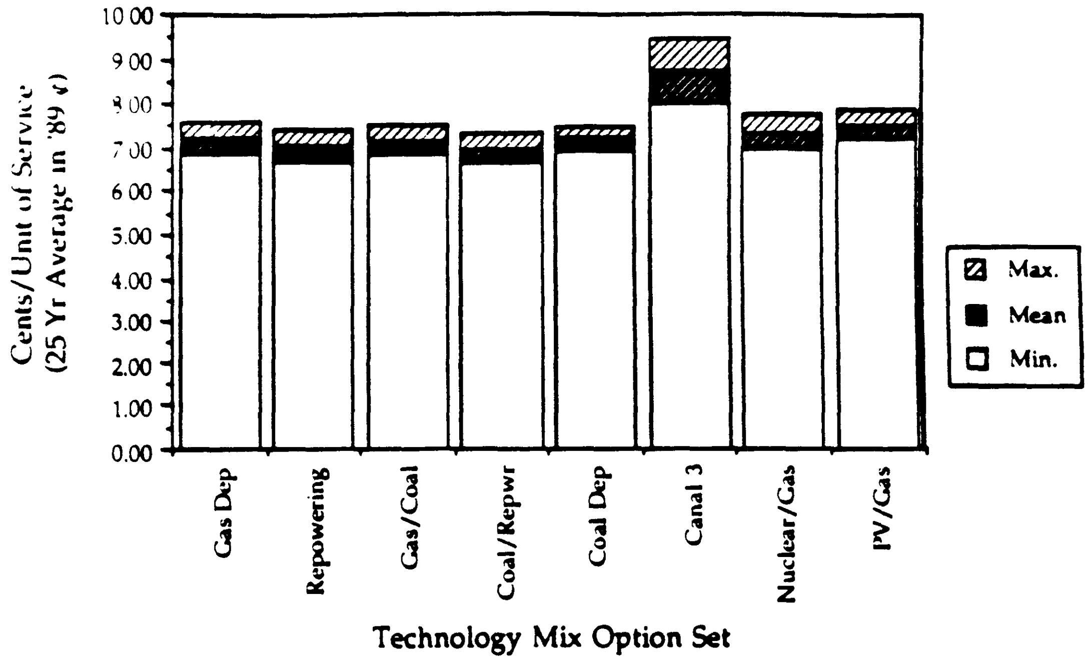
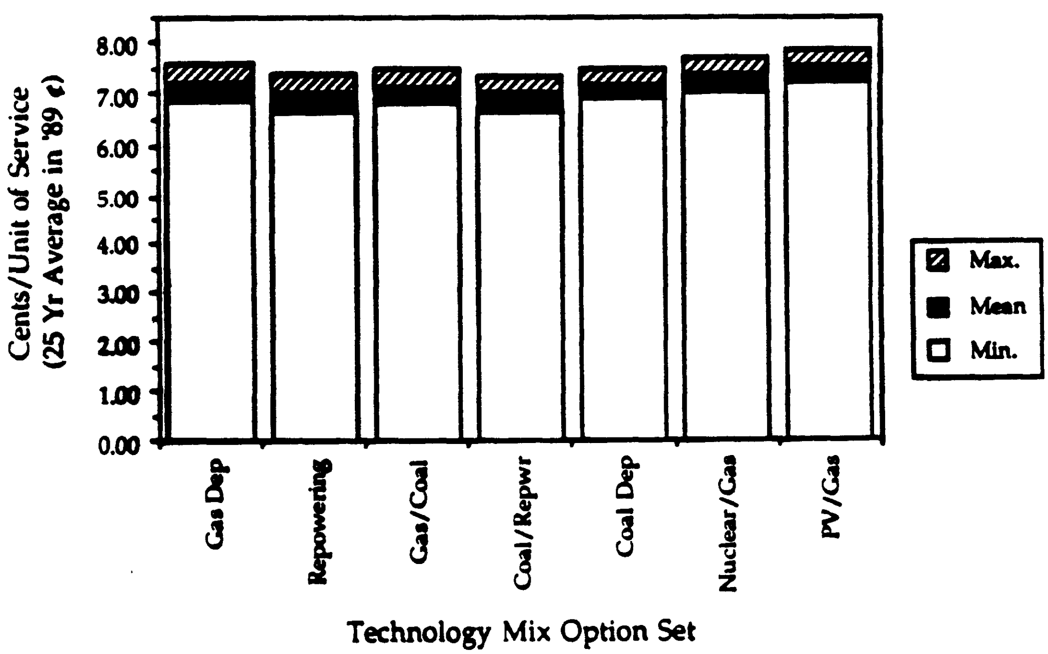


Figure 6.2 - Average Unit Cost of Service by Supply-Option Set

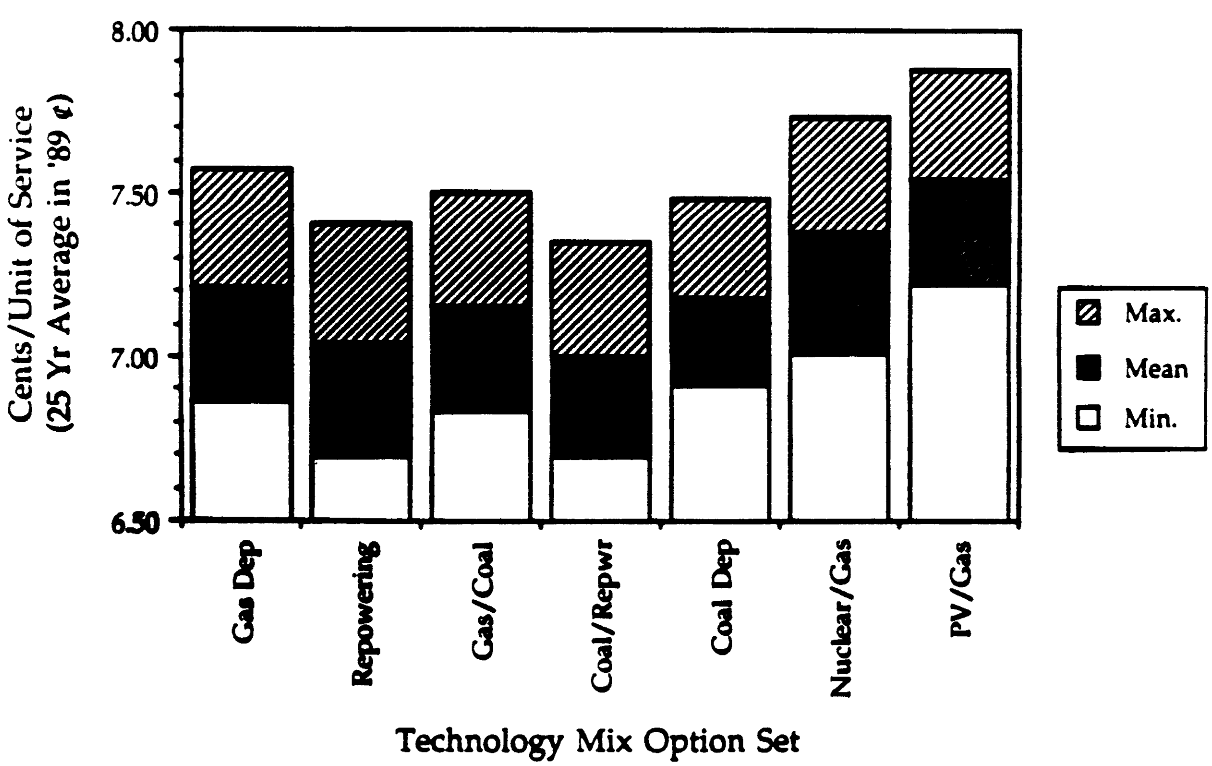
(Canal 3 Results Excluded)



Excluding Canal 3 in this way is a good example of how graphical presentation (scale compression) can influence how results are perceived. This is also important when considering whether absolute or relative results should be shown. Absolute results are typically shown by a scale that starts at zero, while relative results are shown more clearly by a scale that brackets the minimum and maximum values. This report generally presents results on an absolute basis with a zero-based scale, unless specifically focusing on presentation of relative results. Figure 6.3 shows this effect, emphasizing the relative differences between the same results shown above in Figure 6.2.

Figure 6.3 - Average Unit Cost of Service by Supply-Option Set

(Canal 3 Results Excluded)



While this type of graph clearly shows minimum, average, and maximum values, it can obscure some of the underlying results. Results which depend upon fuel price or load growth may may have individual data points grouped into 2 or three ranges. Such bi-modal or tri-modal distributions can be seen later in the two attribute tradeoff curves.

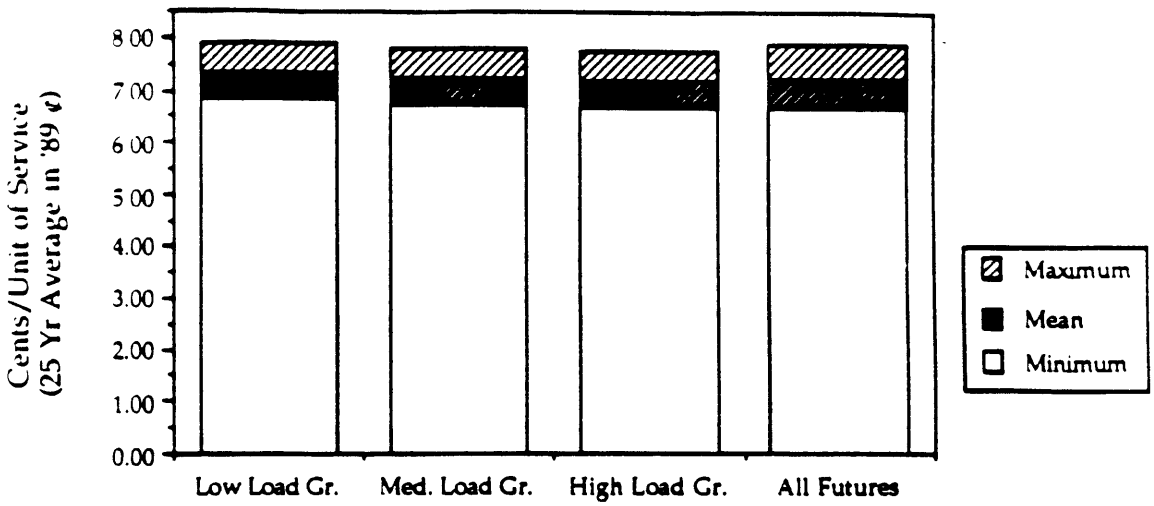
6.3 Single Attribute Trends Due to Uncertainties

This section of the chapter presents how the primary attributes are affected by the three different uncertainties considered; load growth, fuel price, and customer responsiveness to DSM programs. These attributes are divided in the order as they were described in section 6.1; namely by cost, emissions, and reliability.

Unit Cost of Service

Although the total cost of providing electricity naturally follows electrical load growth, the cost per unit of service actually declines as load growth increases. This is shown in Figure 6.4.

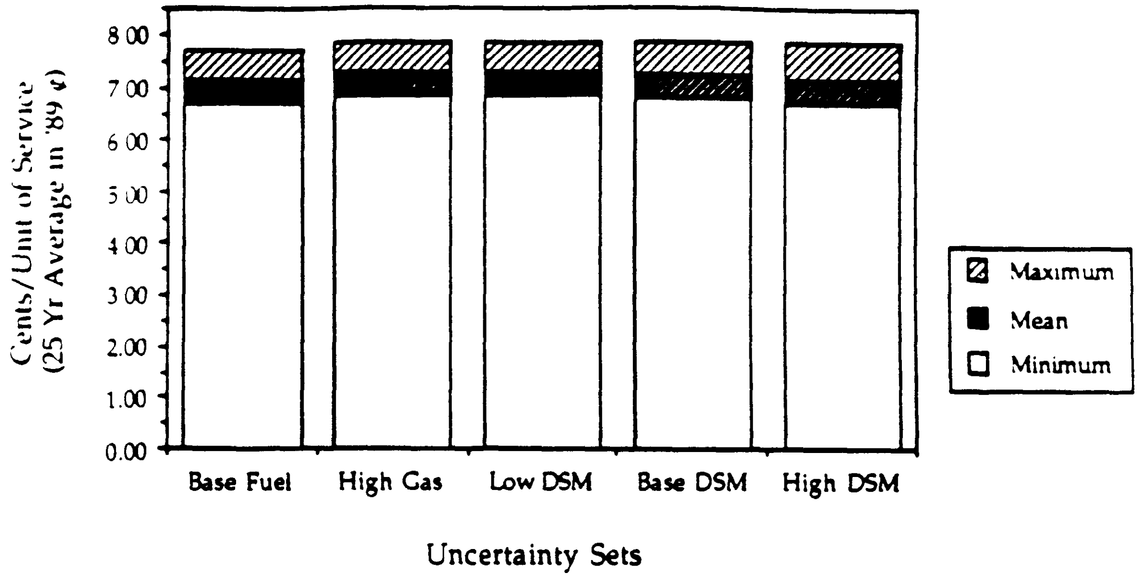
Figure 6.4 - Unit Cost of Service vs. Load Growth



This dependence of cost on load growth is small compared to the effects of other uncertainties and strategies (from low growth to high growth the mean cost only decreases by 0.135, or 1.9%). This decline is due to the fact that increased load growth requires new generating capacity, which has a higher efficiency than existing capacity and hence lower fuel costs, to be added at an increased rate. Higher load growth scenarios had lower average reserve margins, due to the smaller size of new units relative to overall system size. This lower reserve margin reduces slightly the effect of adding new, more efficient capacity, but the trend is still apparent.

The average cost per unit of electric service increases as natural gas prices rise relative to the cost of oil, as shown in Figure 6.5.

Figure 6.5 - Unit Cost of Service vs. Fuel Price and DSM Responsiveness



This is also a relatively small shift in cost (the mean increases by 0.143, or 2.0%). Some generation shifts from gas to other fuels, but not enough to offset the relative increase in gas price. However this slight increase is averaged in the graph above over all strategies. By looking ahead at the tradeoff curves, we can see that gas dependent strategies are slightly more sensitive to this uncertainty.

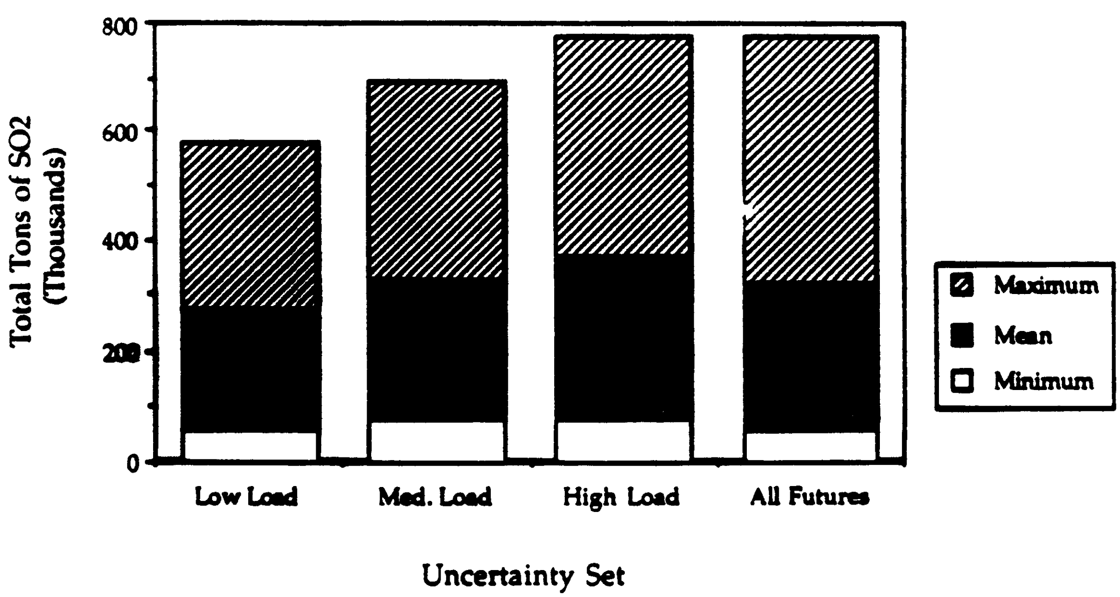
The average unit cost of service also decreases as DSM responsiveness increases (from low to high DSM response, the decrease is 0.144, or 2.0%). This slight decrease is logical because the DSM responsiveness uncertainty specifies greater or lesser response to DSM programs with no change in cost, but the efficiency gains are relatively small and greatly diluted by all other costs. It should also be noted the maximum UCS increases with DSM responsiveness, indicating a trend counter to the average in at least some cases. This may be due to the fact that in some cases high DSM responsiveness cuts the need for new generating capacity, and hence loses the relative benefits of new, higher efficiency units.

In general, none of these uncertainties have a major impact on the cost of service, averaged over all strategies and other uncertainties. The cost differences are small, and the variability differences are also small. Thus, any important cost results will be due to different strategies, and whatever gains may be realized without large cost increases due to the uncertainties shown here.

Emissions

Total SO_2 emissions, the primary attribute chosen to reflect "regional" acid rain environmental effects, increase significantly with load growth as shown in Figure 6.6, even though emissions per kWh of electricity decrease (from low to high load growth, emissions increase by 94,600 tons, or 34.4%).

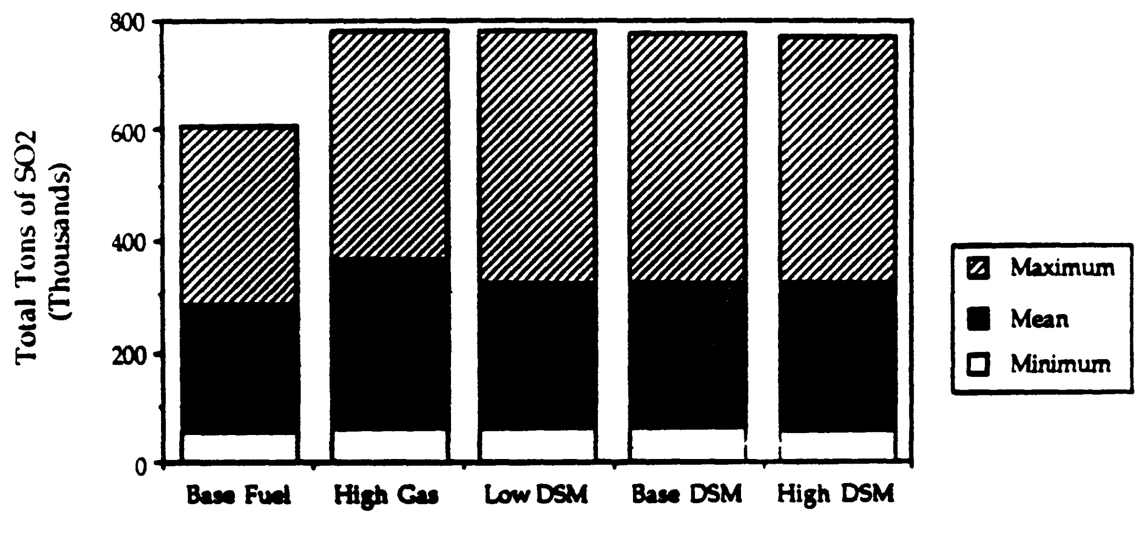
Figure 6.6 - SO_2 Emissions vs. Load Growth



Despite the fact that all new generating technologies considered were very clean in SO_2 emissions, increased load growth requires more generation, and hence higher total emissions. While the maximum, average, and minimum emissions all increase, there is a relatively large variance in emissions for each load growth. This is due to the range of emissions produced by different technology mix and alternate fueling option-sets.

Total emissions of SO_2 also depend on the price of natural gas relative to oil, as shown in Figure 6.7.

Figure 6.7 - SO_2 Emissions vs. Fuel Price and DSM Responsiveness

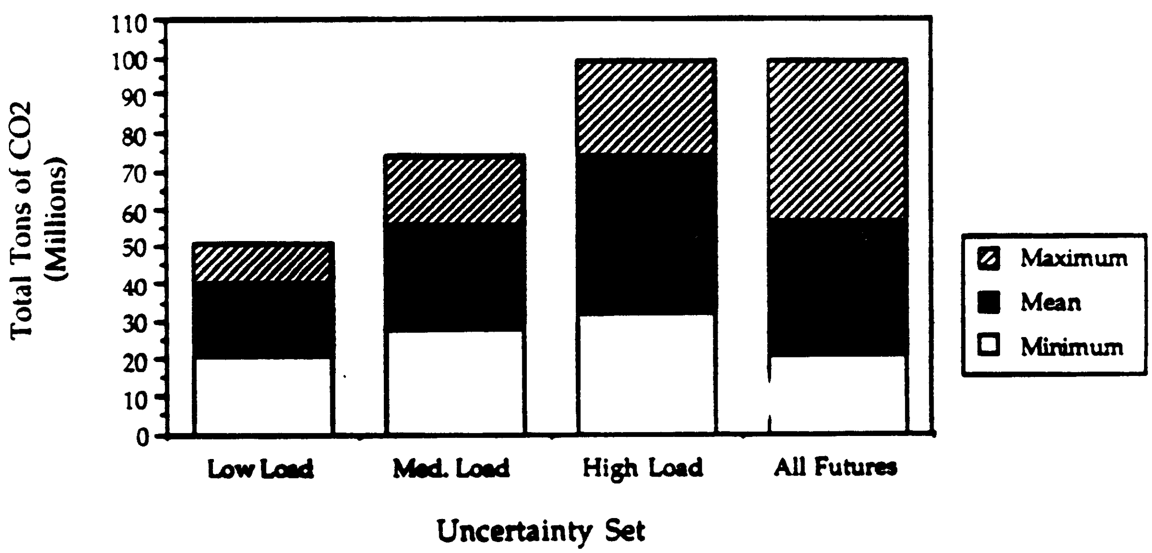


As might be expected, lower gas prices produce less SO_2, while higher natural gas prices drive a fuel shift to burn more oil, producing higher SO_2 emissions. From lower to higher gas prices the increase in mean emissions is 81,500 tons, or 28.9%). This increase in SO_2 is consistent for maximum, average and minimum values, and the large variation for each case reveals a dependence on other factors.

There is also a very slight trend for SO_2 emissions to decrease as customer response to DSM measures increases. This is a consistent and reasonable trend, as DSM savings reduce emissions, but the amount of reduction is almost insignificant compared to the total variation (from low to high DSM response the reduction in average SO2 emissions is only 2600 tons, or 0.8%).

Total CO_2 emissions, the primary attribute chosen to reflect "global" environmental concerns over climate change also increase with load growth, as shown in Figure 6.8 below. From low to high load growth, the average CO_2 emissions increase by 33.9 million tons, or 85.1%.

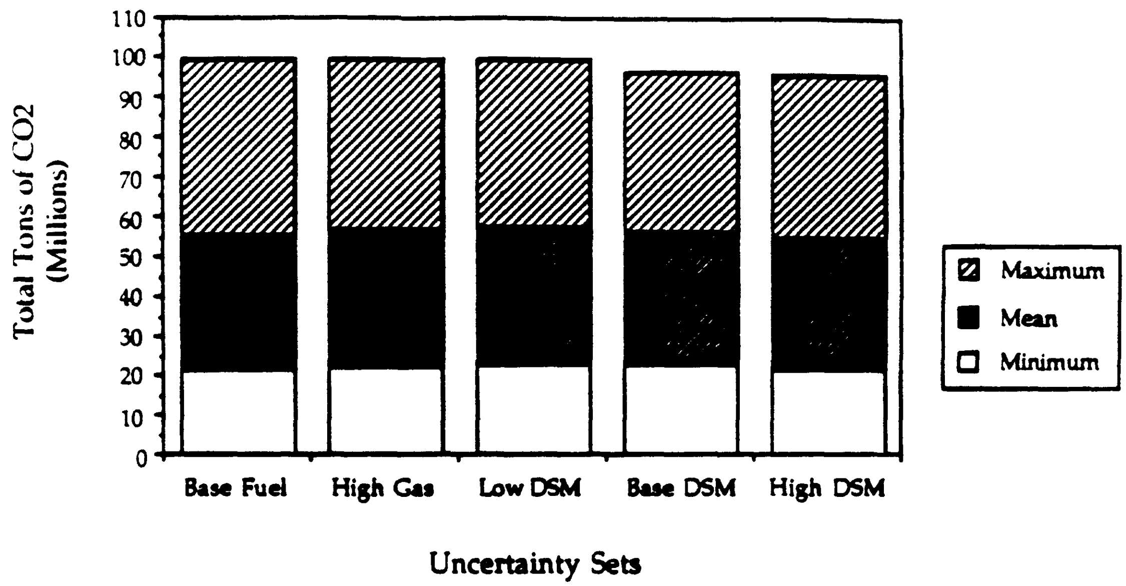
Figure 6.8 - CO_2 Emissions vs. Load Growth



The CO_2 emissions per kWh may or may not increase, based on the fuel carbon content and efficiency of the strategy's technology mix (the tradeoff of SO_2 vs. CO_2 emissions per kWh is explicitly addressed later in section 6.5). In this case, the range of variation in CO_2 emissions also increases as load growth increases, reflecting the increased impact of different technology mixes as total load grows.

Total CO_2 emission depend upon the other uncertainties to a much smaller extent, as shown in Figure 6.11.

Figure 6.9 - CO_2 Emissions vs. Fuel Price and DSM Responsiveness



Total CO_2 emissions decline *very* slightly with lower natural gas prices (on average only 1.00 million tons, or 1.8%). Higher natural gas prices shift some consumption to oil, but the CO_2 decline is much less than for SO_2 because the carbon content advantage of natural gas over oil is much less than its sulfur content advantage. Once again, this result is consistent for the maximum, average and minimum, but very small compared to the variation in either the lower or higher natural gas price case.

As with SO_2, higher DSM responsiveness means a small decrease in total CO_2 emissions, due to increased DSM energy savings (from low to high DSM response average emissions increase by 2.41 million tons, or 4.4%). The trend is consistent, but again almost insignificant compared to the overall range of variation.

As mentioned above, the SO_2 results and to a lesser extent the CO_2 results seen are determined by the relative consumption of natural gas vs. Oil 6. In particular, SO_2 emissions are strongly correlated to the amount of 2.2% sulfur Oil 6. This correlation is shown in Table 6.2 below. As could be expected, this correlation depends strongly upon whether high or low sulfur Oil 6 is burned. Where the correlation is statistically significant, the correlation is shown in bold type.

Table 6.2 - Correlation of Fuels Burned (in Btu's) and Emissions (in Tons)

	Scenarios Burning		
	Low Sulfur Oil 6	High Sulfur Oil 6	Coal
Sulfur Dioxide	.365	**.985**	.041
Nitrous Oxides	.450	**.919**	.013
Suspended Particulates	.100	**.914**	-.153
Carbon Dioxide	.488	.360	.716

Figures 6.10 and 6.11 below present the total cumulative consumption of Oil 6 over the range of all three uncertainties. In particular, the significant decrease in Oil 6 consumption for base natural gas prices vs. higher natural gas prices support the decline in total SO_2 emissions (from base to higher gas prices, average Oil 6 consumption increases by 70 trillion Btu's, or 16.8%).

Figure 6.10 - Cumulative Oil 6 Consumption vs. Load Growth

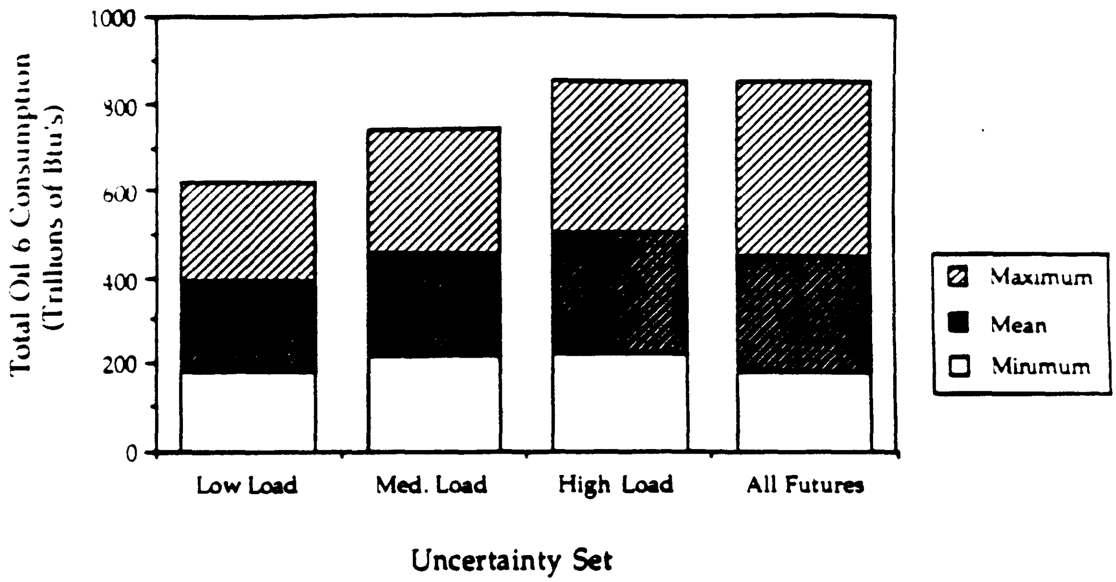
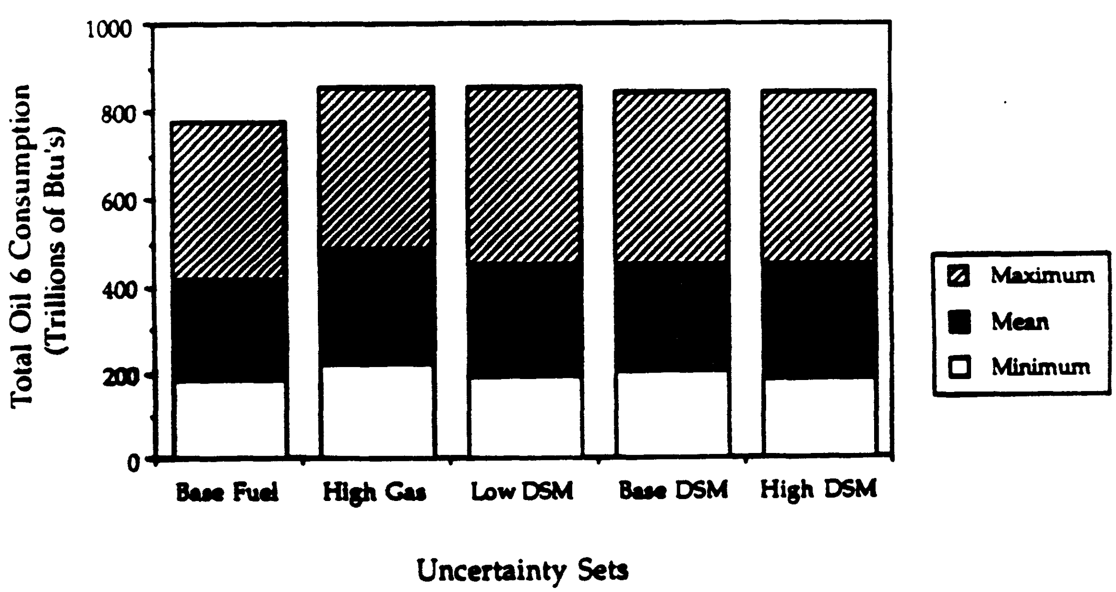


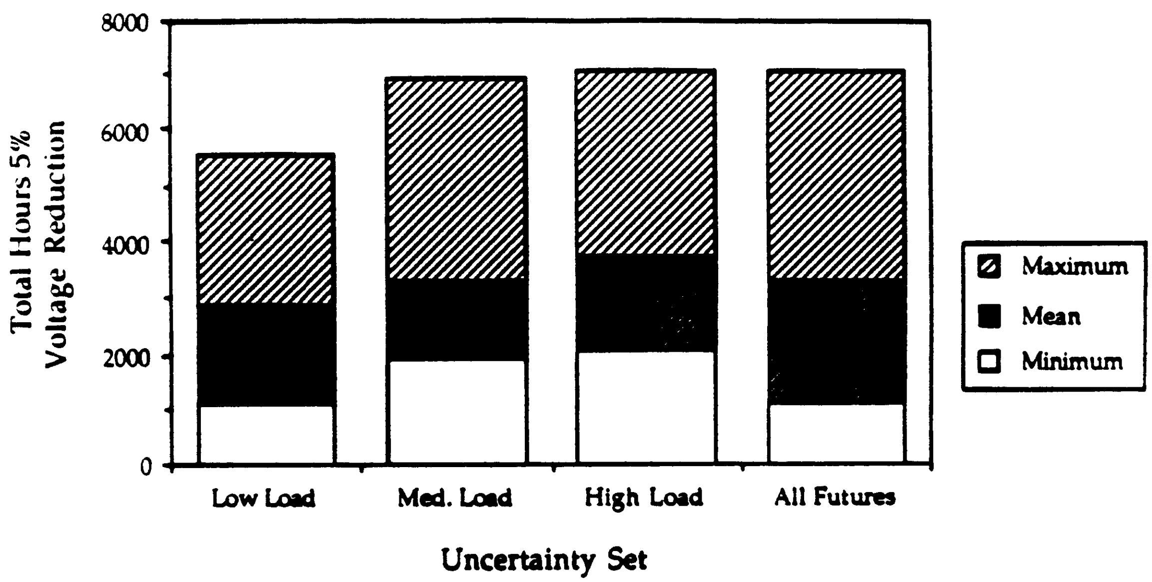
Figure 6.11 - Cumulative Oil 6 Consumption vs. Fuel Price & DSM Responsiveness



Reliability

The number of hours spent in 5% voltage reductions (OP-4 Action 13) increases as load growth increases from low to high (on average by 850 hours, or 29 3%), as shown in Figure 6.12 below.

Figure 6.12 - Hours 5% Voltage Reduction vs. Load Growth

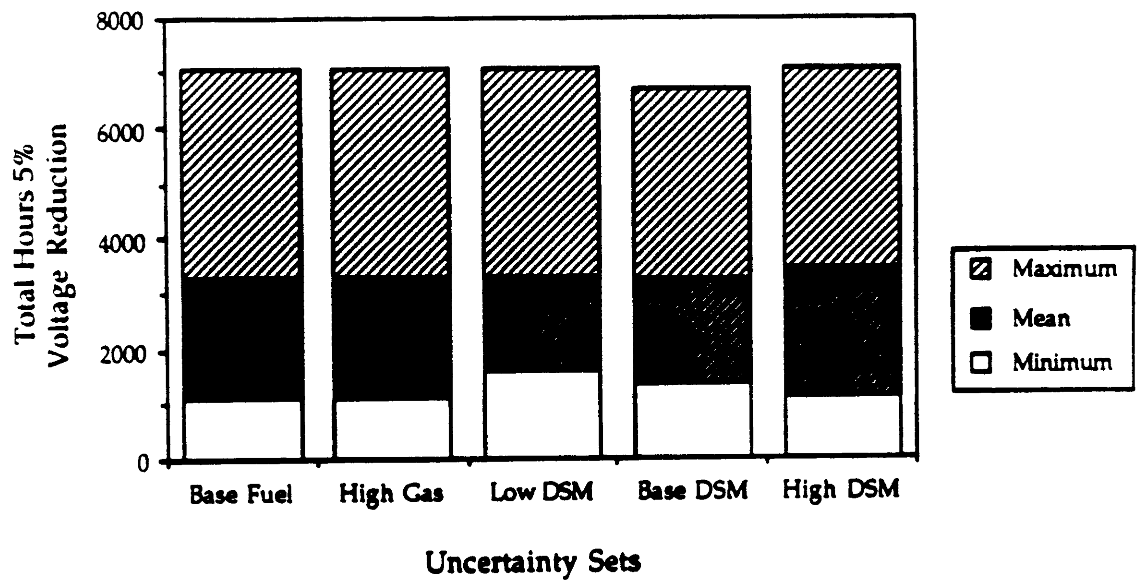


Since new plants are more reliable than old plants, and high load growth requires a larger proportion of newer plants, this result is not straightforward to explain. The reason for this trend was an algorithmic bias in the results of the Prespecified Pathway (PSP) planning program. It planned capacity additions with higher reserve margins for low load growth scenarios and lower reserve margins for high load growth scenarios. Although the Prespecified Pathway planning program attempts to meet its target reserve margin without going below it, it is able to do so more easily when new MW requirements are large in comparison with unit sizes.

Thus, the results seem reasonable since the Prespecified Pathway program mimics a realistic planning process.

System reliability does not depend significantly on the other uncertainties of natural gas fuel prices or DSM responsiveness, as shown in Figure 6.13.

Figure 6.13 - Hours 5% Voltage Reduction vs. Fuel Price & DSM Responsiveness



Thus, any shifts between older oil-fired capacity and newer gas-fired capacity driven by the relative price of natural gas do not seem to have any effects on reliability. The DSM Responsiveness uncertainty shows some slight variations without any clear trend, and the variations are clearly insignificant.

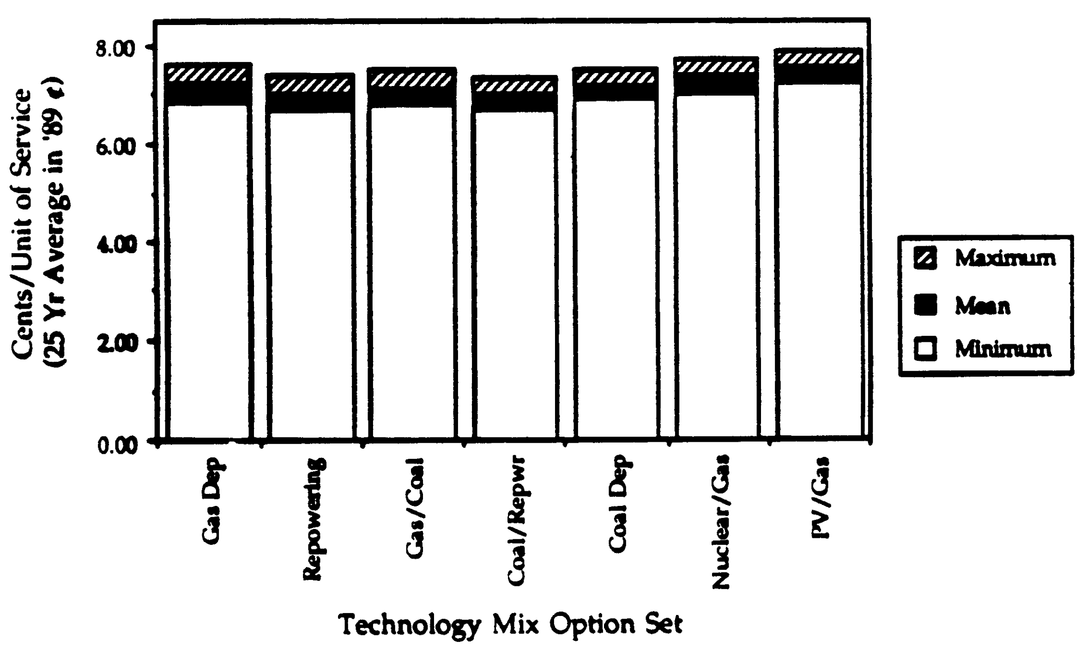
6.4 Single Attribute Trends Due to Option-Sets

This section of the chapter describes how the results for single primary attributes depend upon the different choices available to the utility. As described in Chapter 5, these options include technology mix supply-side option-sets, demand-side DSM program option-sets, and planning and operational options based on fuel choice and target reserve margin. The results of these choices are again divided and presented here by the issues of Cost, Emissions, and Reliability.

Unit Cost of Service

As we have seen before above when eliminating the Canal 3 option-set, the unit cost of electrical service depends significantly, if not greatly, upon the choice of the remaining supply-side option-sets. These results are shown again in Figure 6.14 below.

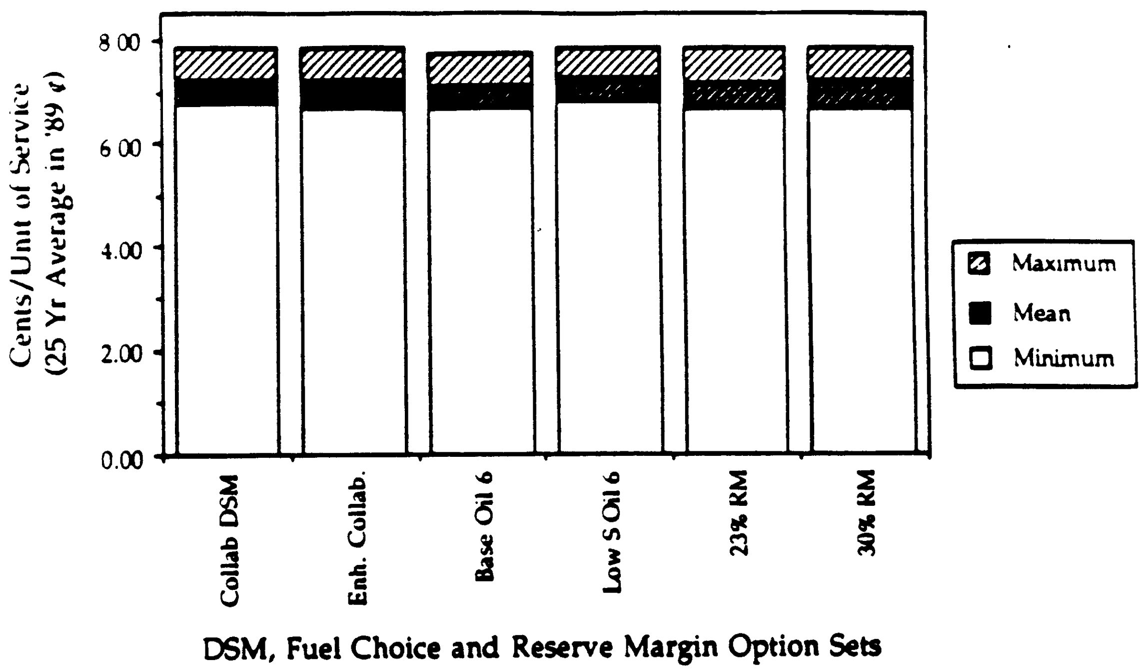
Figure 6.14 - Unit Cost of Service vs. Supply-Side Option-Set



Three conclusions may be drawn from this graph. First, the cost of service results may be generally grouped. The repowering option-sets are the cheapest in average cost (Repowering and Coal & Repowering are both 7.0 ¢/unit of service). They are followed by option-sets in rough order of increasing fuel price (Coal Dependent, Gas & Coal, and Gas Dependent are all 7.2 ¢/unit of service), and finally by the nuclear and renewable options (Nuclear & Gas and Photovoltaics & Gas are 7.4 and 7.5 ¢/unit of service respectively). Second, the range in variation between these option sets is not great (at most 7.1%), so that if any of the option-sets has any great advantages, they may be purchased by a relatively modest premium. Third, the range between maximum and minimum for each supply-side option-set is relatively small and constant over all option-sets (0.6 to 0.7 ¢/unit of service). This means that variations due to uncertainties and other choices are about the same as the differences due to technology mix, and will probably not make an overwhelming difference. Although the difference is slight, the Coal Dependent option set has the lowest variability, reflecting the fact that coal is the cheapest fuel, which insulates this option-set from fuel price changes due to natural gas scarcity or changes in oil prices.

The variations in cost of service due to DSM program choice, low vs. regular sulfur Oil 6, and 23% vs. 30% target reserve margins are shown in Figure 6.15.

Figure 6.15 - Unit Cost of Service vs. DSM Option-Set, Sulfur Content, & Reserve Margin

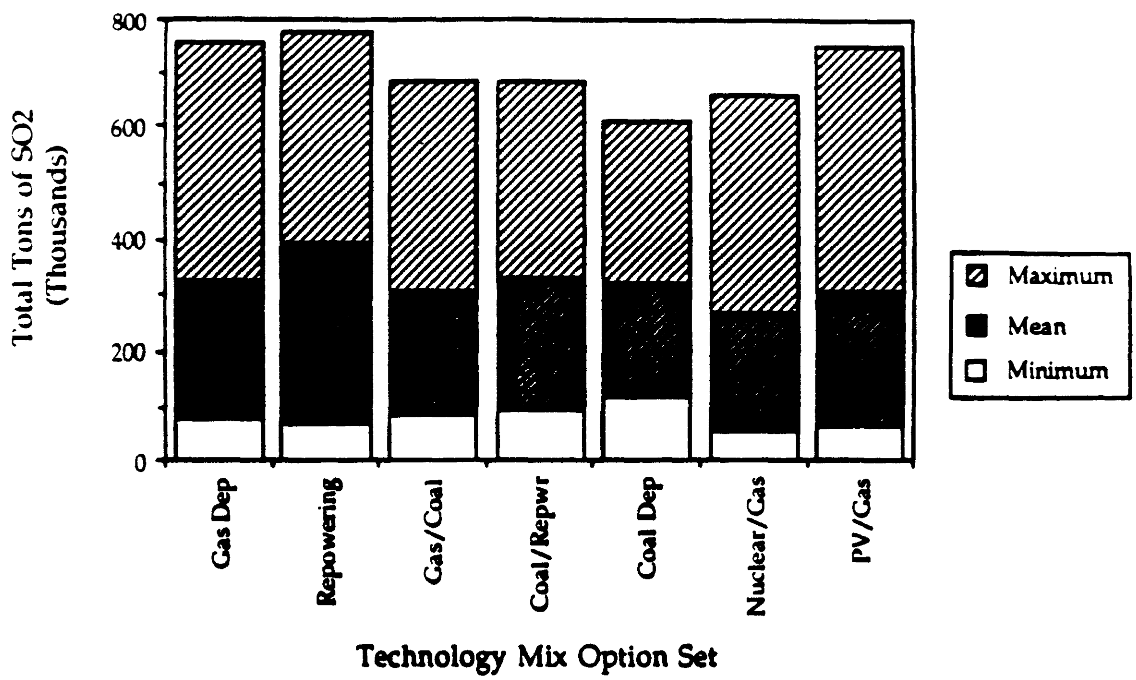


The Enhanced Collaborative DSM option-set is slightly cheaper than the Collaborative DSM option-set (0.1 ¢/unit of service for the maximum and minimum, and not at all for the average). The price premium for burning low sulfur Oil 6 is slightly larger (0.2¢/unit of service, or 2.8%), and the price premium for the higher target reserve margin is just barely perceptible (0.1 ¢/unit of service in the maximum case, or 1.3%). These cost differences are so small that any advantages the option-sets may offer with respect to other attributes will cost, at most, a small premium. These results seem consistent and have a moderate and consistent range of variability.

Emissions

Total SO_2 emissions depend significantly upon the choice of supply-side technology mix, as can be seen in Figure 6.16 below.

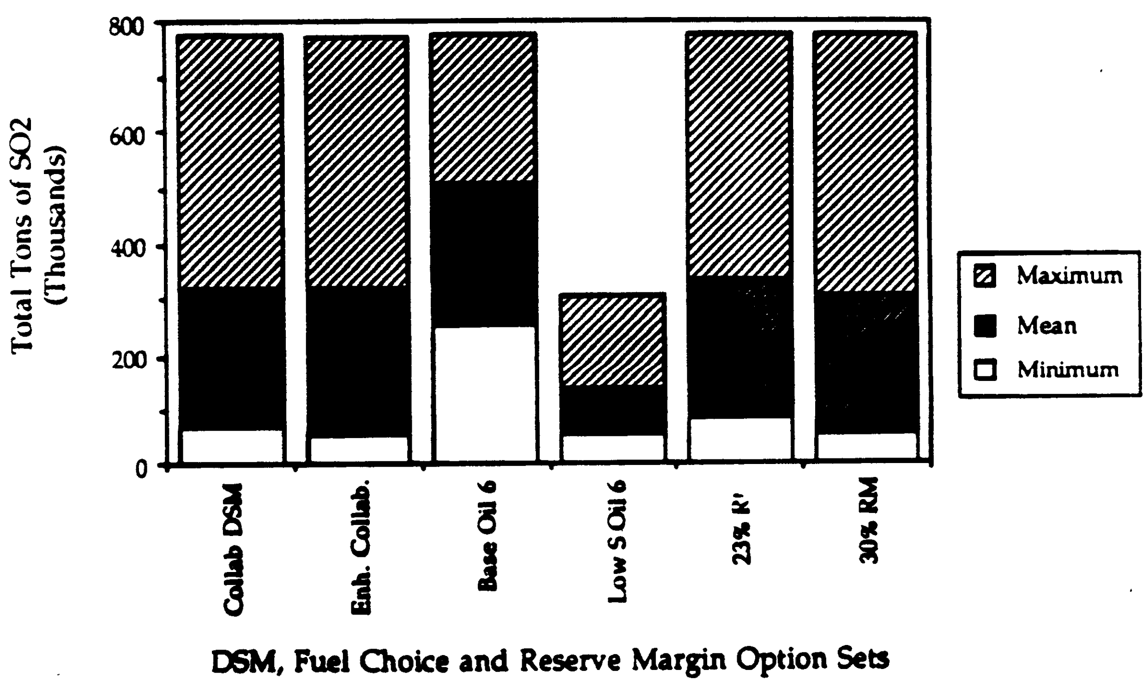
Figure 6.16 - Total SO_2 Emissions vs. Supply-Side Option-Set



SO_2 emissions are lowest for the Nuclear & Gas and Photovoltaics & Gas option-sets (averaging 273 and 306 thousand tons respectively). These are followed roughly in order by the coal/gas, coal, and gas fueled mixes (308, 323, and 325 thousand tons respectively), and topped by the Coal/Repowering and Repowering option-sets (332 and 392 thousand tons respectively). The cleanness of the coal-fired option sets emphasizes the positive impact of the clean coal technologies used. The Repowering option-sets are dirtiest on average because they keep dirtier old plants in service (some are refueled, but all are less efficient), but their minimum emissions can be very clean. This large variability is due to a dependence on how much the old repowered plants are run, which in turn depends upon load growth, reserve margin and fuel prices. While the variability is largest for Repowering (710 thousand tons), it is striking for all single option-sets, revealing that uncertainties (like fuel prices) and especially other options (like Oil 6 sulfur content) must play a major role, regardless of technology mix.

This dependence of SO_2 emissions on other option choices is strongly shown in Figure 6.17.

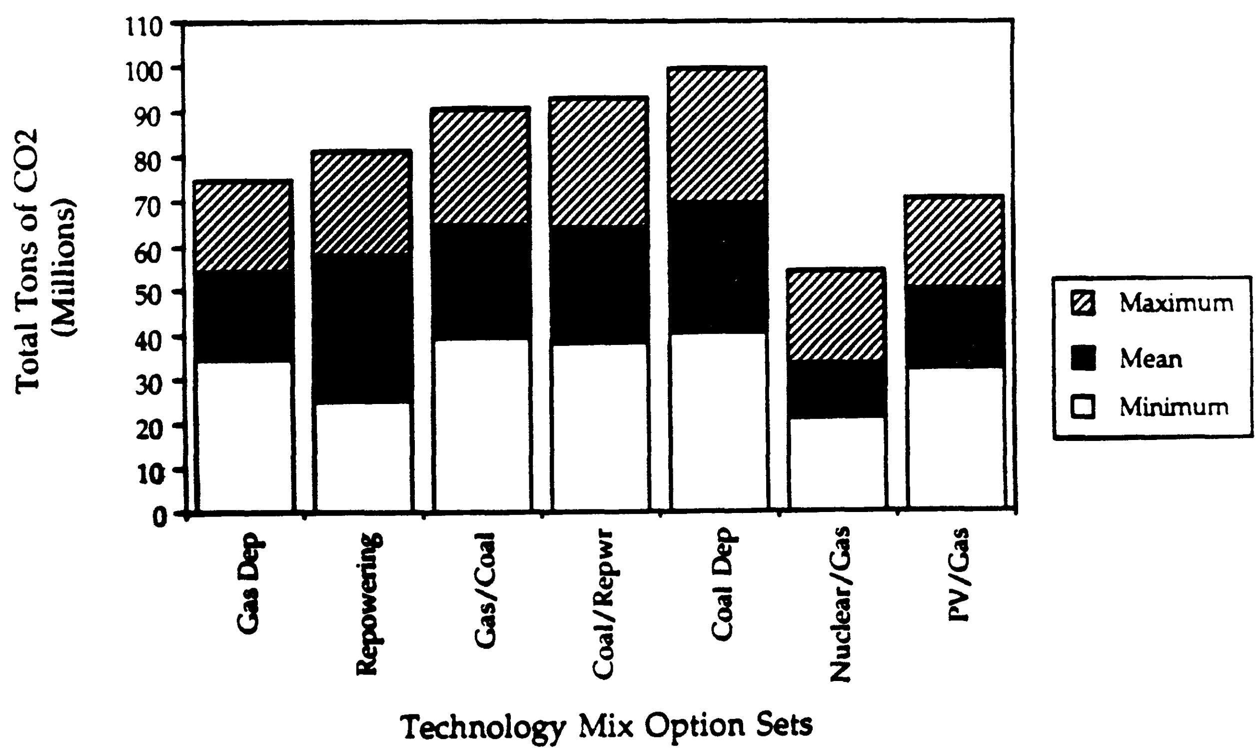
Figure 6.17 - Total SO_2 Emissions vs. DSM Option-Set, Sulfur Content, & Reserve Margin



Here we can see the dramatic impact of requiring the burning of low sulfur Oil 6. Under this requirement, average SO2 emissions decrease by 368 thousand tons, or 72.7%). As we saw in the cost section above, this large reduction SO_2 is purchased by a relatively small increase in the cost of service (only 2.8%). This tradeoff will be made more explicit in Section 6.5 below. The Enhanced Collaborative DSM option-set shows a slight reduction in maximum and minimum emissions over the Collaborative option-set, but the average emissions are approximately equal (322 vs. 323 thousand tons). High 30% target reserve margin shows a slight reduction in average emissions over the base 23% target reserve margin (335 to 311 thousand tons, or 7.2%). Reductions from both the DSM or reserve margin options are available for a small or even negative cost.

Total cumulative emissions of CO_2 also depend significantly upon the supply-side choice of technology mix or option-set, as seen in Figure 6.18.

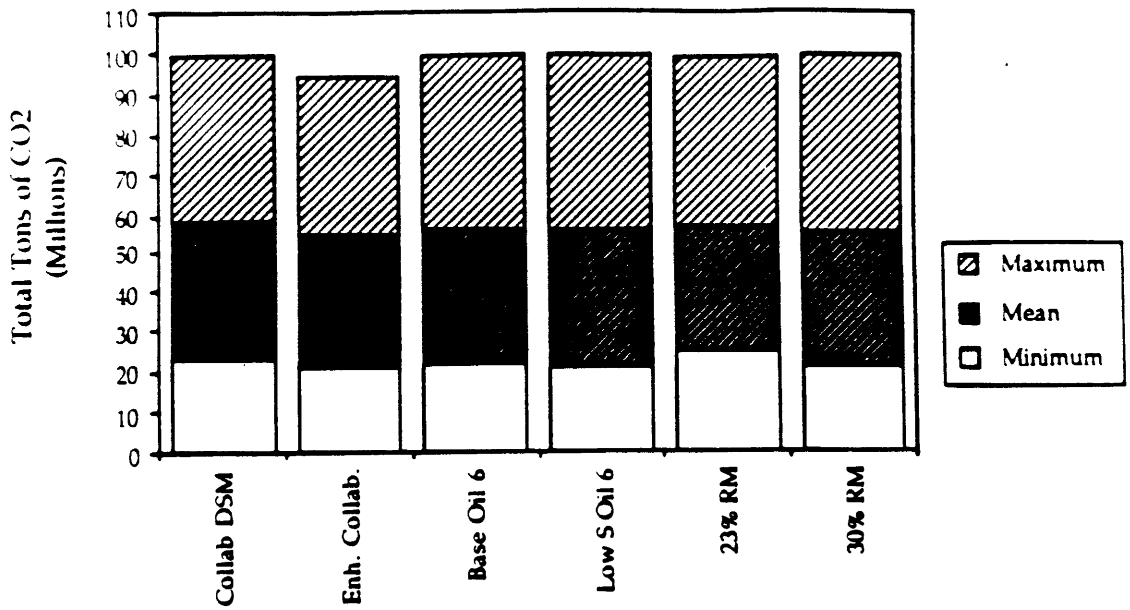
Figure 6.18 - Total CO_2 Emissions vs. Supply-Side Option-Set



As before, the Nuclear & Gas and the Photovoltaic & Gas option-sets have low emissions with relatively low variability (average emissions are 34 and 50 million tons, respectively). However, the order for the next best option-sets is changed relative to those which perform well for SO_2 emissions. The Gas Dependent and Repowering option sets are the next best (54 and 58 million tons on average), due to the lower carbon content of natural gas, while the coal-burning option-sets come last in order of their increasing coal dependence. Coal & Repowering and Gas & Coal have average emissions of 64 million tons each, and the Coal Dependent option-set has average emissions of 70 million tons. Thus we can see that there are tradeoffs between the SO_2 and CO_2 performance of different option-sets, as well as between CO_2 and cost. The overall variability of results for each option set is less than for SO_2, because the effects of changing fuels are much smaller. Repowering remains the most variable option-set (26 to 81 million tons on average), again reflecting a dependence on how much older, more inefficient plants are used.

The effect of choices other than technology mix on CO2 emissions is much smaller, as shown in Figure 6.19.

Figure 6.19 - Total CO_2 Emissions vs. DSM Option-Set, Sulfur Content, & Reserve Margin



DSM, Fuel Choice and Reserve Margin Option Sets

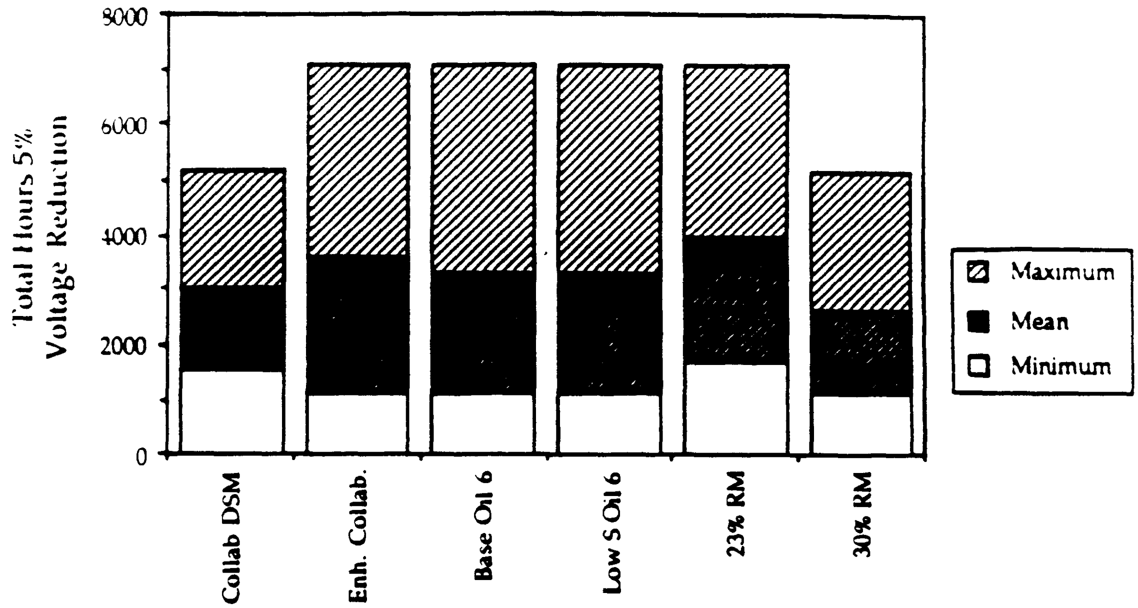
Although the choice of sulfur content for Oil 6 has a dramatic impact on SO_2 emissions, Figure 6.19 shows that (as we would expect) it has no impact on CO_2 emissions. The Enhanced Collaborative DSM option-set has a small average CO_2 emissions advantage over the Collaborative option-set (average emission decrease from 58 to 55 million tons, or 8.6%), which compares with no advantage either way for both average SO2 emission and average cost. The higher 30% target reserve margin has no advantage over the base 23% target reserve margin in average CO_2 emissions, although the minimum emissions are slightly reduced. Finally, all three choices have a consistent and high variability in the results (approximately 75 million tons, or 77% of the maximum), reflecting the effect of technology mix and load growth on total emissions.

Reliability

The reliability of the COM/Elec system depends primarily upon the reserve margin of the system, and only secondarily upon options or uncertainties that are correlated with reserve margin. The cumulative number of hours spent in 5% voltage reduction (OP-4 Action 13) depended upon the supply-side option-set only insofar as the reserve margin was correlated to the technology mix chosen. This correlation is a by product of the Prespecified Pathway planning program, based upon unit lead times for different technologies, and the effect of unit sizes ("lumpiness") by technology vs. the amount of capacity required. Because the 5% voltage reduction hours were correlated to technology mix reserve margins, and not to the technology mix outage probabilities, graphing reliability vs. supply-side option-set was not reasonable.

Instead, Figure 6.20 shows reliability directly against the other options of target reserve margin, Oil 6 fuel choice, and DSM program choice.

Figure 6.20 - Total Hours 5% Voltage Reduction vs. DSM Option-Set, Sulfur Content, & Reserve Margin



DSM, Fuel Choice and Reserve Margin Option Sets

As can be seen, the higher 30% target reserve margin has a strong effect in increasing reliability (decreasing voltage reduction hours). The average reduction in hours spent under 5% voltage reduction is from 3996 to 2645 hours, or 33.8%. In addition to there simply being more capacity to handle peak loads, the higher reserve margin gives additional weight to new vs. old plants, which are more reliable as well as more efficient. As we recall from the cost part of this section, this improvement comes at no average increase in cost. There is *some* cost for the improvement in reliability which does not show in the averages, and this is further illustrated by a tradeoff curve in Section 6.5 below.

As might be expected, the sulfur content of Oil 6 has no effect on reliability. However the demand-side DSM option-set has a mixed effect. Increasing DSM from the Collaborative to the Enhanced Collaborative option-sets decreases the average and worst reliability while improving the best reliability. This happens because the scenarios with Enhanced Collaborative DSM span a wider range of reserve margins, so that the worst reliability decreases and the best reliability increases. The average decreases (605 hours, or 16.7%), because for a fixed average reserve margin Collaborative scenarios are more reliable than Enhanced Collaborative scenarios (except for the photovoltaic scenarios). These effects are due to increased "lumpiness," because under increased DSM less new capacity is needed and new units planned by the Prespecified Pathway planning program are a larger fraction of total generating capacity. This is not true for the photovoltaic scenarios, where peak capacity is determined by load during winter nights.

6.5 Pairwise Multiple Attribute Tradeoff Curves

Having examined the effects of single uncertainties and strategies on the outcomes of the various primary attributes, we are now prepared to see what tradeoffs are given by the different strategies under different futures. These tradeoffs are shown for two attributes at a time in the form of a scatterplot, as described in Chapter 2. Each point on the scatterplot represents a single strategy, with its position showing its performance on each of the attribute axes.

As was shown in Chapter 2, the strategies which are worse in both attributes are dominated, and can be eliminated from consideration, leaving the dominant set which embodies the real tradeoffs available in the form of a tradeoff curve. Points which are sufficiently near to the tradeoff curve (within some uncertainty bandwidth) may also be considered significantly dominant, and those strategies which are on or near the tradeoff curve over the range of futures can be considered robust.

A scatterplot graph may be drawn with points for single, multiple or even all futures. In general, showing points for all 18 futures is confusing. If the result or trend being identified does not change significantly with future uncertainties, then the future identified as being of the highest interest by the Consumer Advisory Groups has been shown. Where trends do change by future then results are shown for the best, worst, and highest-interest futures. As described in section 4.4 of Chapter 4, the Consumer Advisory Groups responded to questionnaires prioritizing uncertainties. The best and worst futures (based on cost and emissions) and the future judged to be of highest-interest by the Consumer Advisory Groups were as follows.

Future	Load Growth	DSM Responsiveness	Natural Gas Fuel Price
Best	Low	High	Low
Highest-Interest	Base	High	High
Worst	High	Low	High

The Best, Highest-Interest and Worst futures are sometimes abbreviated LBHL, BBHH and HBLH, with the second character of B indicating the base level cost of capital used.

Each strategy shown depends on four choices (technology mix, DSM level, fuel choice, and target reserve margin). Where the effects of a choice are particularly significant, the scatterplot's strategy points may form a group or "cloud". These groupings may be shown in the graphs below by a second tradeoff curve or dividing line.

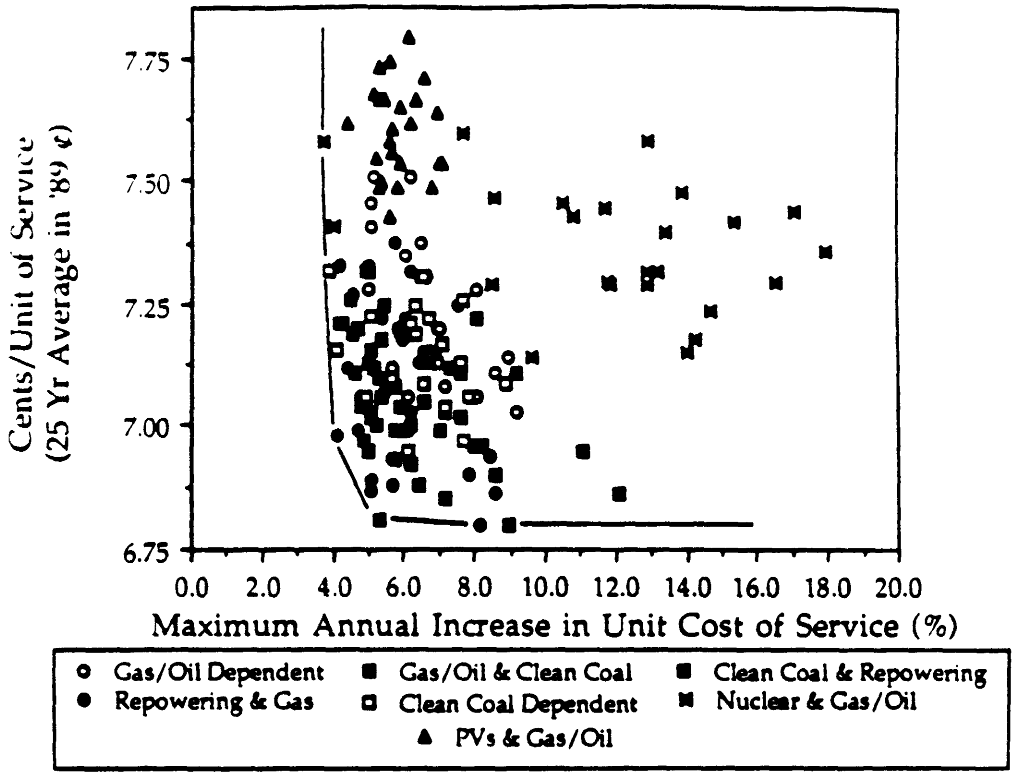
The tradeoff results below are presented by pairs of primary attributes in roughly the same order as the single attributes presented above. Cost attributes are presented first, showing the tradeoff between the cost of service and the maximum annual change in cost of service, or "rateshock". This is followed by the tradeoffs between cost and environmental attributes, and then by the tradeoff between the regional and global (SO_2 and CO_2) environmental attributes. Finally the tradeoffs between cost and reliability of service are presented.

Unit Cost of Service vs. Rateshock

The scatterplot for unit cost of service vs. rateshock is shown below in Figure 6.21. As described in section 6.1 above, the cost of service attribute is the average unit cost of service (abbreviated UCS), and rateshock is measured by the maximum annual increase in the unit cost of service over the study period. This scatterplot shows data for the best, worst, and highest-interest futures described above.

Figure 6.21 - Cost of Service vs. Rateshock

(Best, Worst & Highest-Interest Futures)



This scatterplot shows several different things. First, rateshock is smallest for some of the Repowering and Coal & Repowering technology options, but varies a fair amount. Rateshock then increases from Coal Dependent to Gas & Coal, Gas Dependent, Photovoltaics & Gas, and finally Nuclear & Gas. The "cloud" of points for each technology option-set overlaps with the others, so this trend is not overwhelming. What is striking is that the left (low rateshock) side of the tradeoff curve is very steep or nearly vertical, so that any decreases in rateshock are purchased at a very steep cost. The technology choices at the "knee" of the curve are supply-side option-sets C/D - Repowering and G/M - Coal & Repowering, and this is true for all three futures. This is not surprising, since repowering is cheap (especially under the assumptions made for COM/Elec), and the low cost and low rate shock go together in all futures.

The high cost side of the scatterplot is more interesting. The Photovoltaics & Gas technology option is costly, but has rateshock results that are consistently quite low, even though not the very lowest. In comparison, the Nuclear & Gas option-set is also costly, but has by far the widest variation in rateshock results. Under the worst future (high load growth), nuclear power can have rateshock results that are as low as any, but under medium or low load growth rateshock can be extreme.

Other trends are harder to see from a single tradeoff curve but had small, consistent effects. Low sulfur oil increased UCS slightly, but decreased rateshock slightly. Increasing load growth decreased both UCS and rateshock slightly. Fuel prices, DSM option-set and DSM responsiveness all had no significant effects.

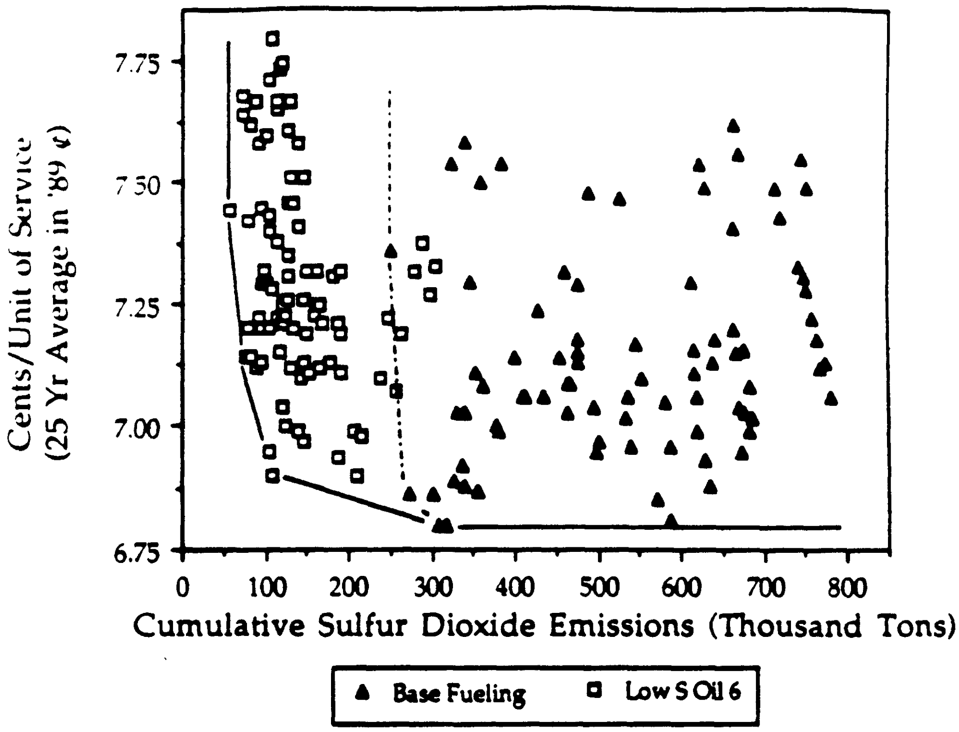
Unit Cost of Service vs. Environmental Effects

Unit Cost of Service vs. Sulfur Dioxide Emissions

The tradeoff between the unit cost of service and the regional, acid rain environmental effects of sulfur dioxide emissions are shown in Figure 6.22. This scatterplot includes results and tradeoff curves for the best, highest-interest, and worst futures. As might be expected from the definition of these futures, these tradeoff curves show that both cost and total emissions increase as the futures move from best to worst.

Figure 6.22 - Cost of Service vs. Total SO_2 Emissions

(Best, Worst & Highest-Interest Futures)

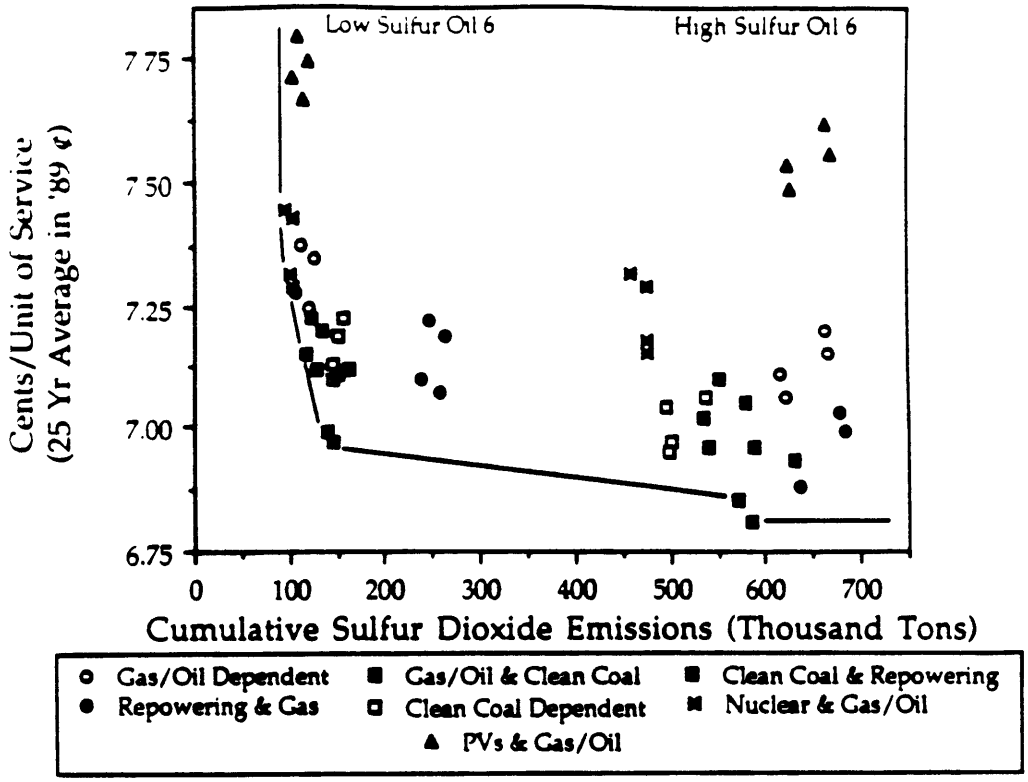


The predominant story shown by this graph is the large reduction in total SO_2 emissions that can be purchased by a relatively low cost by using low sulfur Oil 6. This can be seen in Figure 6.22 by the different symbols representing this fueling option, and the almost complete separation between these two clouds of symbols.

Given that fuel choice is the single most influential option, what about the second most important choice of technology option? Four technology-mix option-sets are consistently in the dominant set for all three futures. These are shown by Figure 6.23, which focuses on the future chosen as being of highest interest by the Consumer Advisoıy Groups.

Figure 6.23 - Cost of Service vs. Total SO_2 Emissions

(Highest-Interest Future)



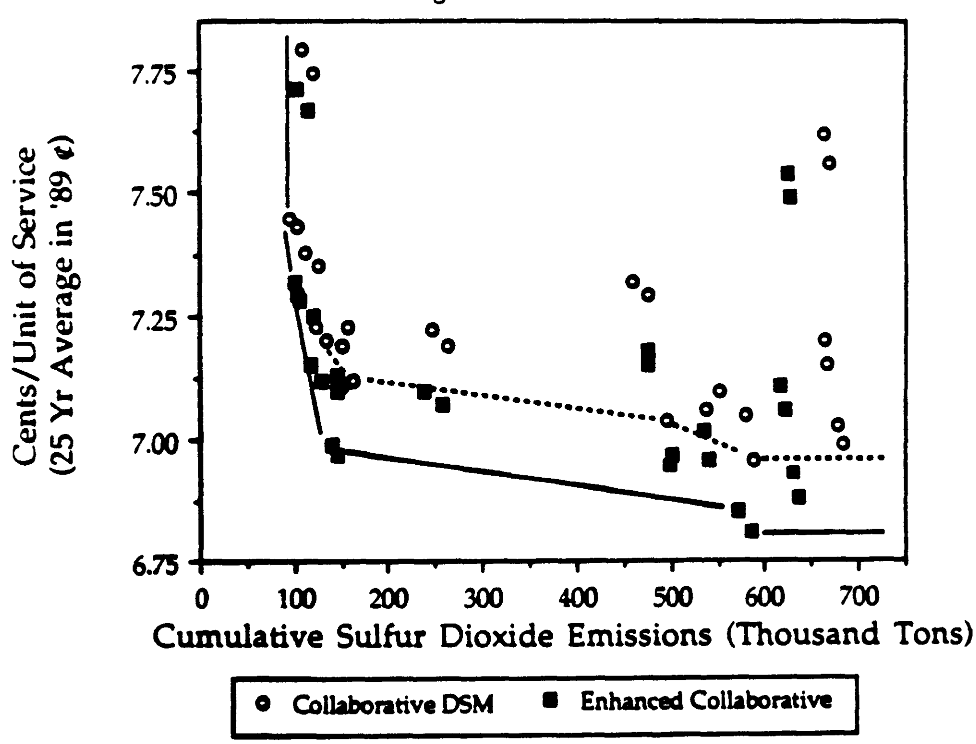
The Coal Dependent and Coal & Repowering supply-side option-sets were the lower cost dominant choices, with Coal & Repowering being slightly cheaper and dirtier. Both of these technology mixes then moved up (more expensive) and to the left (cleaner) with the addition choice of low sulfur Oil 6. These two technologies formed the "knee" or turning point of the tradeoff curve. Moving up in cost from the knee, the technology choice is Gas & Coal, but Gas Dependent is not far from the frontier and is on the frontier for other futures. Finally up in cost from both of these gas burning futures at the extremely clean, very expensive end of the curve is the nuclear option.

What technology choices are dominated on the basis of cost and SO_2 emissions? Clearly the Photovoltaics & Gas option-set was as clean, but much more expensive than the Nuclear & Gas option-set. The more expensive options with high sulfur oil were also clearly dominated. Finally, Repowering was dirtier and more expensive for both fuel options.

These two choices of fuel and technology mix had the largest effects. However, as mentioned in the single attribute trend analysis, the other two choices of DSM option-set and target reserve margin had smaller effects that were consistent among technologies, if not always among futures. Figure 6.24 shows scatterplot results for the highest-interest future with two tradeoff curves for the Collaborative vs. Enhanced Collaborative DSM option-sets.

Figure 6.24 - Cost of Service vs. Total SO_2 Emissions

(Highest-Interest Future)



As can be seen, the Enhanced Collaborative programs are consistently both cleaner <u>and</u> cheaper. Although this result was generally true, the trend was reversed for the worst future, where the DSM responsiveness uncertainty was 50% below expected. This effect was consistent for all technology mixes, except for the Nuclear & Gas and Photovoltaics & Gas option-sets in all futures when DSM responsiveness was low.

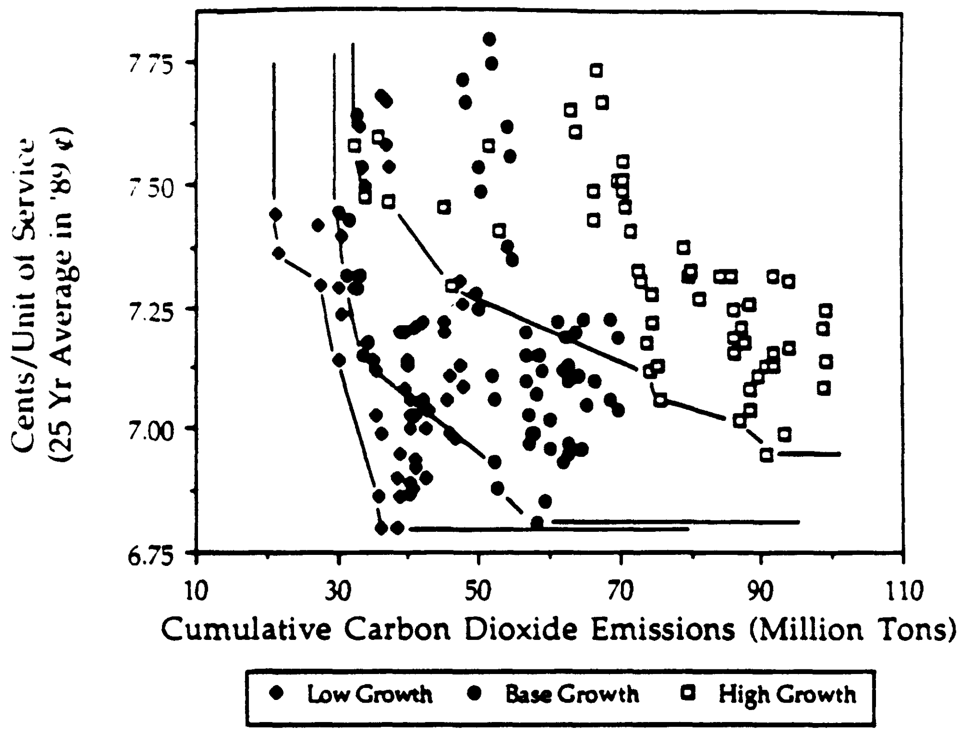
The higher target reserve margin had a similar effect of being slightly cleaner and but slightly more expensive. Because this effect was small, and a tradeoff between cost and emissions (rather than a win-win like the Enhanced Collaborative choice), both target reserve margins are members of the overall tradeoff curve.

Unit Cost of Service vs. Carbon Dioxide Emissions

Because the carbon content of fuels does not vary as much as the sulfur content, and because it cannot be removed with current technologies, the cost vs. CO_2 emissions tradeoffs are significantly different than those for cost vs. SO_2. Figure 6.25 shows the best, worst, and highest-interest futures for unit cost of service and cumulative CO_2 emissions.

Figure 6.25 - Cost of Service vs. Total CO_2 Emissions

(Best, Worst & Highest-Interest Futures)

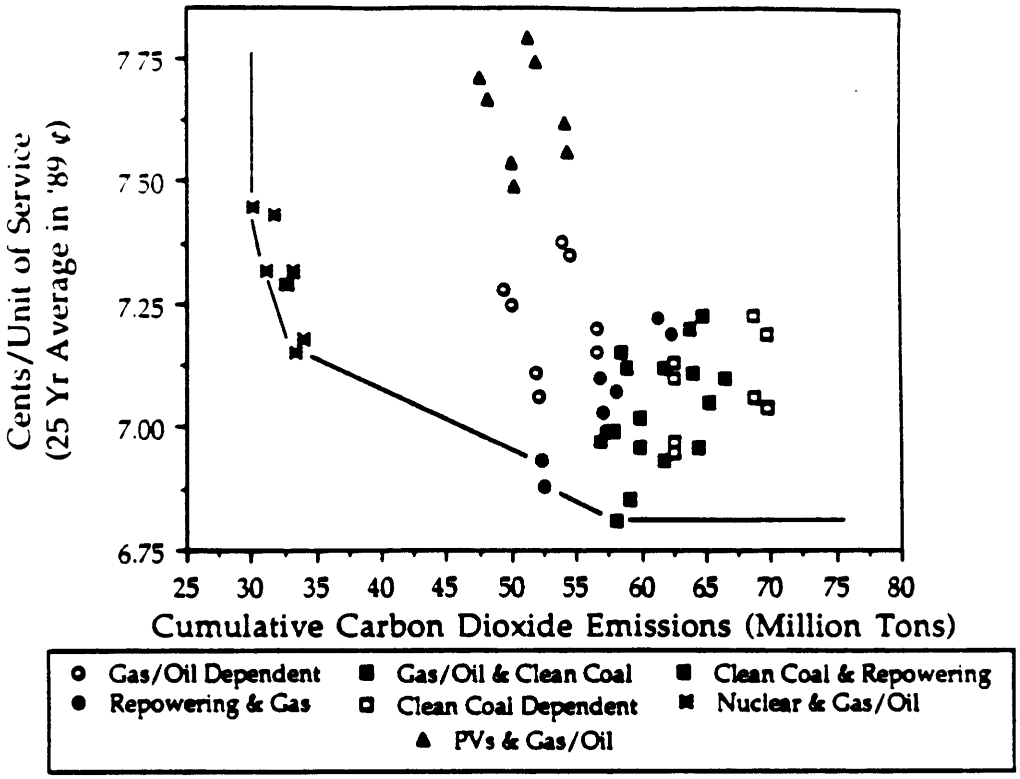


Because emissions are in total tons rather than pounds/kWh, there is a clear shift in CO_2 emissions, but not cost, as the futures change from low to medium to high load growth. This is shown in Figure 6.25, where the "clouds" of points shift directly from left to right as load growth increases.

Given this general trend, which technology choices show up on the tradeoff curve? These results are consistent for all three futures, and are shown in Figure 6.26, which concentrates on the most probable future for greater clarity.

Figure 6.26 - Cost of Service vs. Total CO_2 Emissions

(Highest-Interest Future)



Starting from the cheap but dirty end of the tradeoff curve, the first supply-side option-set is Coal & Repowering. The next option-set is Repowering which is equally cheap but slightly cleaner since fuel shifts from coal to gas which has a lower carbon content. The Gas Dependent option-set is next, and is significantly more expensive with only a marginal decrease in CO_2. Finally, the Nuclear & Gas option-set is up at the clean but expensive end of the tradeoff curve. The Gas & Coal, Coal Dependent, and Photovoltaics & Gas option-sets were clearly dominated and for all three futures. The major shift between futures is that as load growth increases, CO_2 emissions increase much less for the nuclear option-set relative to all other technology choices, as could reasonably be expected.

What about the other three choices of DSM option-set, fuel sulfur content, and target reserve margin? As expected, the fuel sulfur content has no impact in this case except to raise cost, so only high sulfur Oil 6 strategies are on this tradeoff curve. The DSM option set is not quite so clear a story. For the best future and all but the nuclear option-set in the highest-interest future, increased DSM is a win-win improvement in both cost and CO_2 emissions. However for the worst future, the results are mixed and both collaborative and enhanced collaborative option sets appear on the tradeoff curve. As with the SO_2 results, this appears to be the result of the decreased DSM effectiveness resulting from the low DSM uncertainty associated with the worst future.

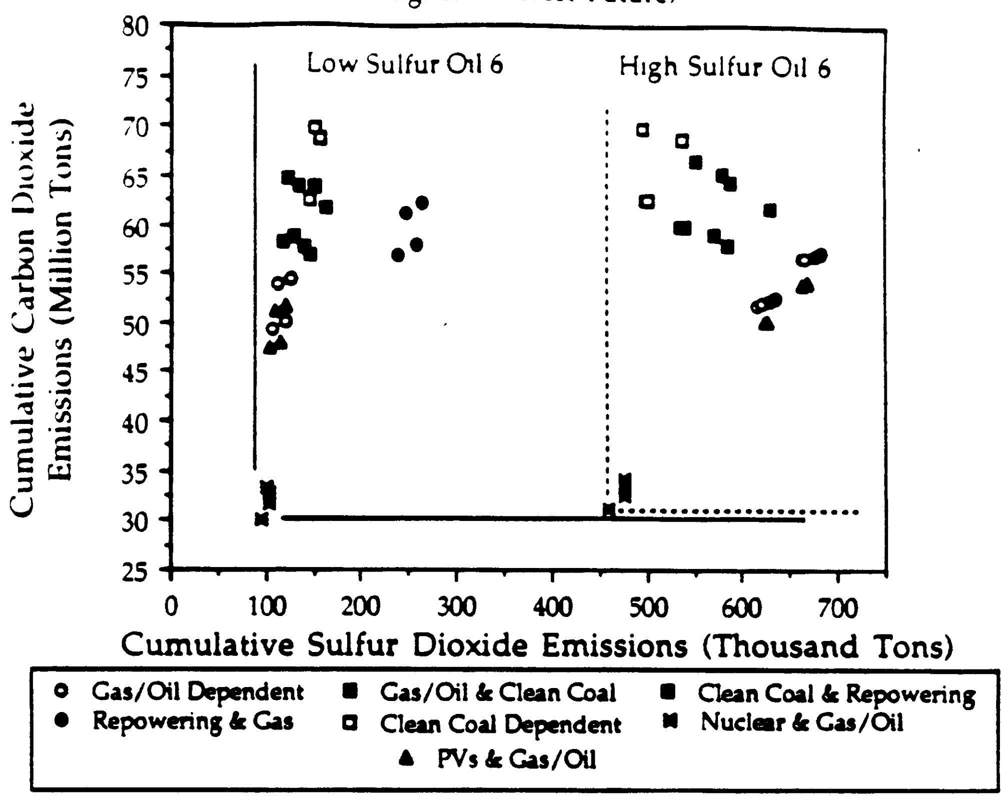
Finally, choice of the higher 30% target reserve margin generally increases costs without decreasing CO_2 emissions enough to push these strategies out to the tradeoff curve. Only in the case of the nuclear option-set does the higher target reserve margin extend the tail of the curve, so that both 23% and 30% reserve margin cases are in the decision set.

Regional vs. Global Environmental Effects

Given the fact that different strategies appear on the cost vs. SO_2 and cost vs. CO_2 tradeoff curves, it is clear that there exists a tradeoff between total cumulative SO_2 and CO_2 emissions. This tradeoff is shown in the scatterplot Figure 6.27.

Figure 6.27 - Total SO_2 Emissions vs. Total CO_2 Emissions

(Highest-Interest Future)



There are two primary points illustrated by this graph. The first is that the choice of low sulfur Oil 6 is still a win-no loss choice, since SO_2 emissions can be reduced with no increase in CO_2. Second is that only the Nuclear & Gas option-set performs well for both attributes. In all three futures, the Nuclear & Gas supply-side option-set is the only technology choice in the dominant set. Photovoltaics & Gas and Gas Dependent come in a distant second and third in this tradeoff where cost is not an issue.

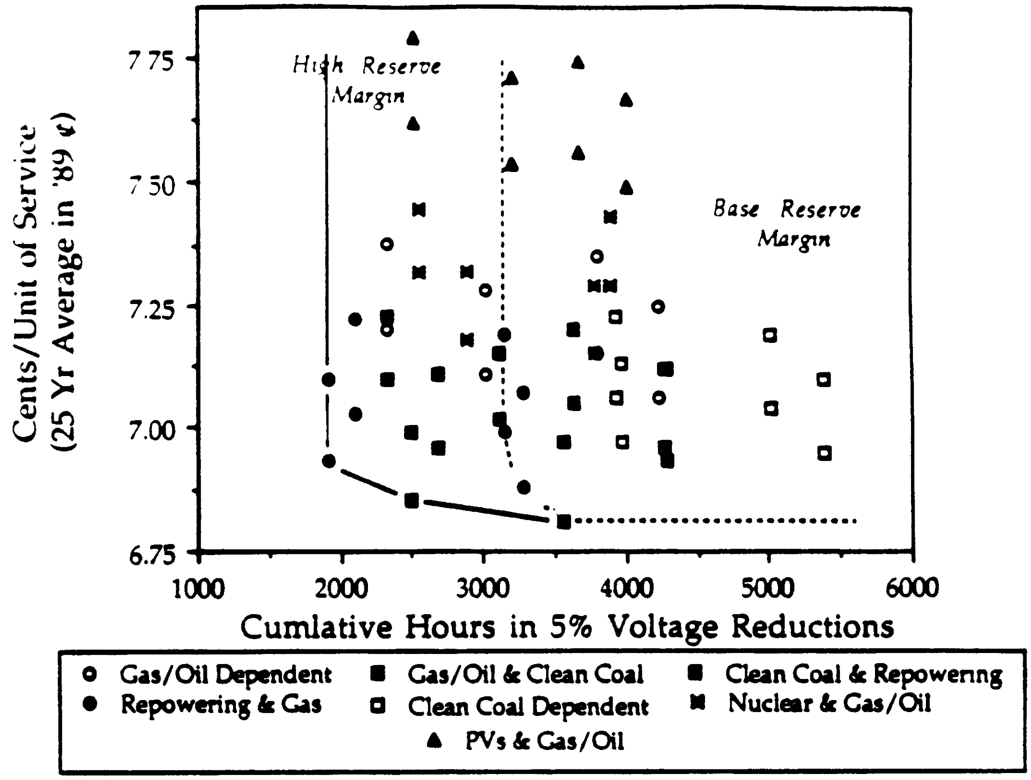
The other two choices of DSM level and target reserve margin have relatively small effects. In the best and highest-interest futures, the Enhanced Collaborative DSM option-set is a clear winner over the Collaborative process, whereas in the worst future the Collaborative level of DSM has lower CO_2 emissions and mixed results for SO_2. Likewise for the target reserve margin option the 30% reserve margin is a clear but very small winner in all cases for SO_2 emissions, but effects on CO_2 are mixed.

Unit Cost of Service vs. Reliability

After cost tradeoffs with rateshock and SO_2 and CO_2 emissions, we turn to cost vs. reliability, as measured by the number of hours spent in OP-4 Action 13, a 5% voltage reduction with ten minutes notice. In this state, COM/Elec's interruptible customers shift over to self generation, so no one is actually out of electricity, but it is the next step to requesting large, non-interruptible customers to reduce consumption and maximize self generation (succeeding steps are public radio requests for load reductions and rolling blackouts). Figure 6.28 shows this tradeoff for the highest-interest future, since results for all three futures are consistent.

Figure 6.28 - Cost of Service vs. Total Hours 5% Voltage Reduction

(Highest-Interest Future)



In all cases, the Repowering and Coal & Repowering supply-side option-sets are the only two technology choices in the dominant set, and both are close to the "knee" or corner of the tradeoff curve, with Repowering being slightly more reliable, and Coal & Repowering being slightly cheaper.

In both cases, these technology choices are combined with the choice of a high target reserve margin (30% vs. the normal 23%). This choice of target reserve margin has a significant effect, because without it the entire tradeoff curve shifts to the right, reducing reliability while retaining the same Repowering and Coal & Repowering supply-side option-sets in the dominant set on the shifted tradeoff frontier. Tradeoff curves for both these reserve margins are shown in Figure 6.28.

The price of natural gas relative to oil (the fuel price uncertainty) had no effect on reliability (only on cost), and the DSM option-set (Collaborative vs.

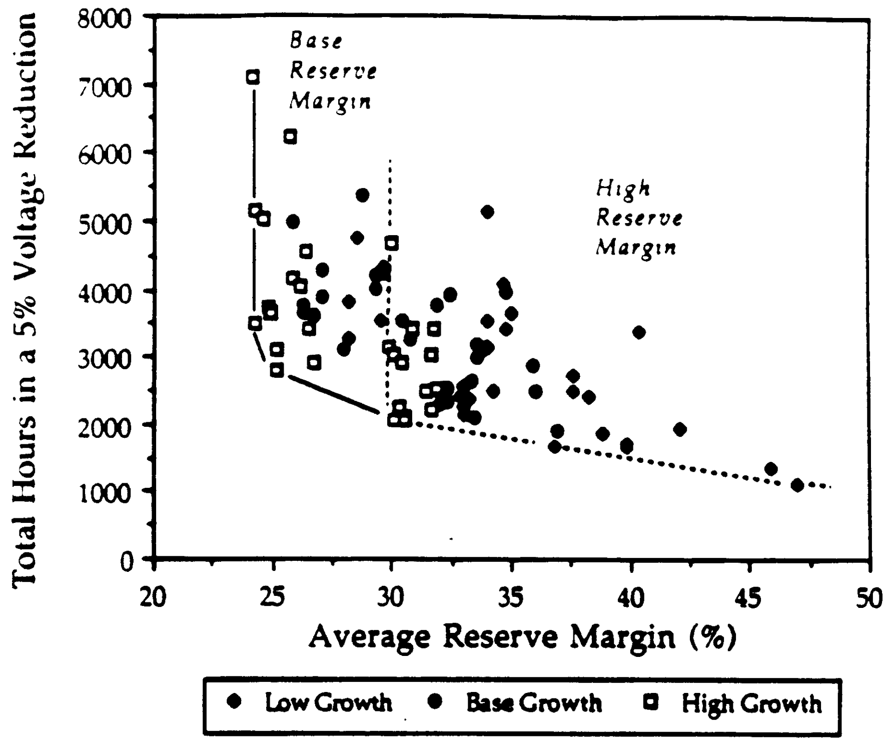
Enhanced Collaborative) had a mixed impact on reliability due to a mixed correlation with reserve margin.

As was noted above in the evaluation of single attributes, reliability is predominantly a function of reserve margin. This is confirmed by the frontier shift seen above. Repowering and Coal & Repowering are the dominant supply-side option-sets because repowering older plants is less expensive, and these choices tended to have higher reserve margins, thereby improving reliability as well. As mentioned before, the Prespecified Pathway program which simulates the planning and commitment of new plants has several reasons (besides its given target reserve margin) for producing different actual reserve margins. Variations in the actual reserve margin are based on reasonable expectations and constraints faced in the actual planning process, such as uncertainty over future loads, interactions between load growth and units already committed, or interactions between load growth rate, unit size, and construction lead times.

It is clear from the interpretation of Figure 6.28 that the reserve margin is the driving force behind reliability in the supply of electric service. This dependence is shown in Figure 6.29 where hours in OP-4 Action 13 is plotted against the average reserve margin.

Figure 6.29 - Total Hours 5% Voltage Reduction vs. Average Reserve Margin

(Best, Worst & Highest-Interest Futures)



Correlation of reserve margin to technology choice is quite weak. Photovoltaic scenarios determine the "knee" of the curve due to their extra "hidden" reserve margin. Extra gas-fired capacity built to meet winter night peak load is also available for added reliability during daylight hours. Repowering scenarios are built to the highest reserve margins by the Prespecified Pathway planning program, and hence are the most reliable.

This scatterplot shows the overall relationship between higher reserve margin and higher reliability by the overall slope of the scatterplot point cloud from lower right to upper left. However, the reserve margin is also inversely correlated to overall load growth. Figure 6.29 shows the scatterplot points identified by their load growth uncertainty. As can be seen, higher load growth means that each new additional unit is a smaller fraction of the total system size, and so increases the average reserve margin by a smaller amount.

Given the dependence of reliability on reserve margin, why does an increase in reliability, given by building to a higher reserve margin, come at such a low cost? Basically, new plants are more efficient than the old plants presently in operation, and a high target reserve margin introduces more new plants which will generate a greater proportion of the electricity. The increased capital costs of these new units are partially offset by reduced fuel and operation and maintenance costs associated with the younger, more efficient new power plants, so that the net result is only a small increase in the unit cost of service.

By examining the trends present in the single attribute results, and then examining how these trends interact in pairs of attributes, this chapter has presented the results and tradeoffs for the COM/Elec Open Planning Process project. These results are summarized, regrouped and discussed by strategy, and explored for systemic interactions next in Chapter 7 - Conclusions.

7.0 Conclusions

This chapter presents the analysis team's conclusions based on experience with the Consumer Advisory Groups, as described in Chapter 4, and on the technical analysis results presented in Chapter 6. The technical conclusions are presented first in parallel order to Chapter 6. The overall single attribute impacts of uncertainties first and the single attribute impacts of strategy choices are summarized second. Third, the tradeoff results are reordered by individual strategy choice (instead of by attribute) and discussed.

The conclusions of the COM/Elec project are then compared with those for the winter 1989-1990 scenario set of the New England project. The conclusions about the Open Planning Process itself are then presented, along with the principal conceptual conclusions of the technical analysis. Finally, possibilities for study in future rounds of the Open Planning Process are outlined.

7.1 Single Attribute Uncertainty Conclusions

Three main conclusions can be drawn about the overall effects of the load growth, fuel price and DSM responsiveness uncertainties. First, for any results which are absolute, cumulative totals rather than results per kWh, load growth is the dominant uncertainty. Total cost and emissions are strongly driven by growth, whereas the unit cost of service and emissions per kWh may rise or fall depending upon fuel choice, technology mix, efficiency, etc.. Since load growth rates depend more on population, economic growth, and price elasticity, and less on utility DSM programs, use of attributes that express results per kWh focuses attention on the significant, relative effects that utility choices can make.

Second, the price of natural gas relative to oil has a significant impact on total SO_2 emissions due to a shift in fuels burned through the alternative loading of power plants. There is no corresponding impact on total CO_2 emissions.

Third, reliability appears to be linked inversely to load growth, due to a relationship between load growth and reserve margin. This dependence of reliability on reserve margin will be seen again, when higher target reserve margins are discussed.

Although some other consistent trends due to uncertainties may be discerned, they are small and relatively insignificant, compared to the much larger variations in results due to the choice of strategies. The uncertainties also seem to have results that are independent of each other, so there does not seem to be significant interaction that could produce countervailing trends.

7.2 Single Attribute Option-Set Conclusions

The main conclusion that can be drawn from the single attribute results is that choices are roughly divided into two groups. The first group of choices includes the Demand-Side options and reserve margin, which have relatively small but consistently positive effects at little or no cost. These small impact choices present relatively easy choices.

For DSM, the Enhanced Collaborative option-set is 8.6% cleaner in CO_2 emissions with SO_2 emissions and cost essentially unchanged. The Enhanced Collaborative option-set does have decreased reliability but this effect is mixed, and can be overcome by choosing a higher target reserve margin. Increasing reserve margin reaps significant reliability gains (a 33.8% reduction in 5% voltage reduction hours) for no increase in average cost.

Technology mix and fuel choice are choices which have larger, but mixed, effects. The choice of supply-side technology mix can make a large difference, but have countervailing trends in cost, SO_2, and CO_2 results. Requiring low sulfur Oil 6 makes a large (73.7%) reduction in average SO_2 emissions at a relatively low, but significant, increase in average costs (2.8%) while having no real impact on CO_2 emissions. Inclusion of a non-carbon emitting baseload generating technology, the Advance Light Water Reactor, significantly reduced average CO_2 emissions by 32%, compared to all the other technology mixes evaluated.

A secondary conclusion is that the different option choices do not interact significantly. Thus, for example, choosing low sulfur oil consistently reduces SO_2 emissions (to different degrees) regardless of the choice of DSM option-set, supply-side option-set, or reserve margin.

7.3 Summary of Tradeoff Conclusions by Option-Sets

Given the primary attribute tradeoff results presented in Chapter 6, a number of conclusions can be drawn about the strategies available to Commonwealth Electric. This section ties together the attribute results by each of the individual technology, demand-side management, planning and system operation choices considered. As before, the unit cost of service is abbreviated below as UCS.

Supply-Side Option-Sets

Because each pair of attributes in the scatterplot tradeoff graphs were discussed separately above, it is necessary to look back at which supply-side option-sets were in the dominant sets for each tradeoff, and which option-sets were dominated in all cases and so eliminated from consideration.

Gas Dependent - This option-set was not quite on the UCS vs. SO_2 tradeoff curve for the highest-interest future, but it was close enough to be considered significantly dominant, and was on the tradeoff curve for other futures. Its slightly higher cost put it above the Coal Dependent option-set. This option-set was also on the UCS vs. CO_2 tradeoff curve, at a significant cost premium over the Coal and Repowering option-set.

For both the UCS vs. SO_2 and UCS vs. CO_2 tradeoff curves, the Gas Dependent option-set was at the clean and expensive end of the tradeoff curve, at a point with such a steep slope that it is evident that the extra reduction in pollution comes at a significantly higher cost. This option-set depends only on natural gas for all new capacity, and it is evident that other option-sets which burn other fuels as well as gas, or which repower old capacity with gas come much closer to the knee of these tradeoff curves. The uncertainty in natural gas prices vs. base oil prices did not make a large difference for this option-set in terms of its position relative to the curve. This trend seems likely to continue even if oil prices grow at a slower or faster rate, since it is the relative price of the fuels which is important in terms of system operation.

Repowering - This option-set was on three different tradeoff curves. Because repowering on the specific sites considered was an inexpensive option, Repowering (and Coal & Repowering) did well on both unit cost of service and rateshock. Both of these option-sets were both on the knee of the UCS vs. Rateshock tradeoff curve. The Repowering option-set was also on the UCS vs. CO_2 tradeoff curve, where it was cleaner than Coal & Repowering but had higher CO_2 emissions than the Gas Dependent option-set. This option-set was also on the UCS vs. Reliability tradeoff curve near the knee where it was slightly more reliable than the Coal & Repowering option-set. However since this reliability is more tied to the reserve margin than any inherent reliability in the technology, this result is less important.

This was also a gas dependent option-set, because almost all the refired capacity burns gas. It is therefore more vulnerable to fuel price shifts than choices which also use coal or nuclear fuels.

Gas & Coal - This option-set was on the UCS vs. SO_2 tradeoff curve, where it was more expensive than Coal Dependent at the knee and less expensive than the clean, high cost nuclear option. It does not appear in the decision set for any of the other tradeoff curves. While it does not perform poorly, it does not stand out from the others. In fact it is only marginally better than the Gas Dependent option set on the UCS vs. SO_2 tradeoff scatterplot and they are so close that they can be considered practically the same for these two attributes. However the Gas Dependent option-set does have consistently lower CO_2 emissions. As might be expected, the Gas & Coal option-set has a less volatility in its unit cost of service than the Gas Dependent strategy, because it is partially insulated from the gas price increase due to its coal-burning component. This option set is often beaten out by the Coal & Repowering option-set, because Coal & Repowering has the same fuel blend (repowered units almost all burn gas) but at lower capital costs.

Coal Dependent - This option-set was on the UCS vs. Rateshock tradeoff curve, but only in the future considered to be the worst by the external consumer advisory group, and even then on the high cost end of the curve. However, it is near the knee of the UCS vs. SO_2 tradeoff curve, where is it slightly cleaner and more expensive than Coal & Repowering. The relatively high carbon content of coal means that this option-set does not do well on the UCS vs. CO_2 tradeoff. However, the increased use of coal means that it is better protected from fuel prices shifts, not just for the gas vs. oil shift modeled, but from other shifts in the price of oil as well! It shares this characteristic with the Nuclear & Gas option-set, but because coal plants can be built before the Advanced Light Water Reactor nuclear plants will be available, this advantage with respect to fuel diversity is available for more of the study period.

Coal & Repowering - This option set is on the tradeoff curve for four different attribute pairs. This does not mean that it is a clear winner, because its characteristics put it down the tail of the tradeoff curve away from the knee in some cases.

Because of the low cost of the repowering component, this option-set is on the knee of the UCS vs. Rateshock curve, along with Repowering. It is on the UCS vs. SO_2 tradeoff curve near the knee, where it is slightly dirtier and cheaper than the Coal Dependent option-set. This position is due to the very low emissions from the clean coal-gasification combined-cycle technology. However, although this option-set is on the UCS vs. CO_2 tradeoff curve it is out on the less expensive, high CO_2 end of the curve due to the high carbon content of the coal. This option-set is also on the UCS vs. Reliability tradeoff curve. Again, this is not a great advantage, because the real story behind reliability is in the reserve margin.

Like the Gas & Coal option-set, this choice is partially insulated from natural gas price shifts by its coal-burning component.

Canal 3 & Gas - As explained at the beginning of Chapter 6, this option-set was too expensive and offered no compensating advantages to compete with the other option-sets. The price disadvantage of trying to refuel an already efficient plant meant that too large a cost was spread over too small an increase in net capacity.

Under any reasonable expectations about the future, this option-set is the worst of all eight considered.

Nuclear & Gas - This had perhaps the most mixed results of any option-set considered. It was consistently expensive, but in the worst future (with high load growth), it can have a low enough rateshock to show up on the high cost tail of the UCS vs. Rateshock tradeoff curve.

As might be expected it is also on the high cost, low emissions tail of the tradeoff curves for both UCS vs. SO_2 and UCS vs. CO_2. Because of this, it dominates all other supply-side option-sets for the SO_2 vs. CO_2 tradeoff. The low emissions strengths of this option-set are enhanced by the fact that nuclear units displace Oil 6 (Canal units 1 & 2) at the bottom of the dispatch order, but are moderated by the fact that advanced light water reactors are not available until the year 2000. Like the Coal Dependent option-set, this option set is relatively insulated from both absolute and relative shifts in the prices of gas and oil, but this benefit occurs only after the year 2000 when the option-set shifts from a dependence on gas-fired units, and adds nuclear units.

Photovoltaics & Gas - This option-set was dominated for all tradeoffs, so it was not on the tradeoff curve in any case. COM/Elec's peak loads occur after dark during the winter, requiring additional gas-fired capacity. The energy price savings due to the photovoltaic generation cannot overcome the capital costs for this extra gas-fired capacity. For COM/Elec's service territory, photovoltaics must compete on energy savings alone with no credit for reducing other capacity needs.

Demand-Side Option-Sets

The choice between the Collaborative and the Enhanced Collaborative programs was clear. The Enhanced Collaborative program option-sets decreased both SO_2 and CO_2 emissions *and* decreased prices. The relative benefits in CO_2 reductions were slightly greater, because efficiency (both DSM and supply-side) is currently the only way aside from non-fossil fuel generators that CO_2 emissions can be reduced. Only in the worst future did increasing DSM have mixed effects, due to poor customer response to utility DSM initiatives.

Planning & Operation Options

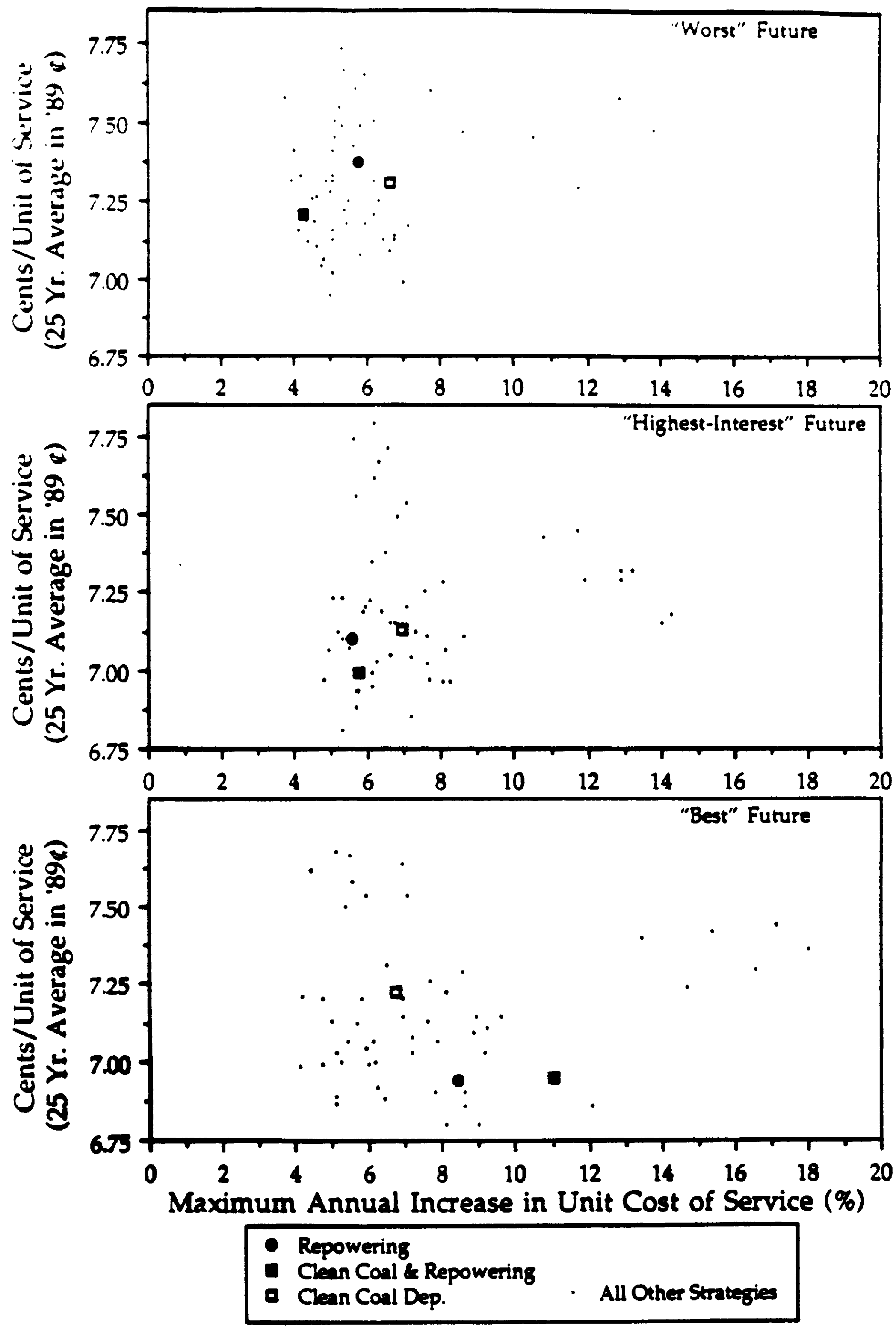
Low Sulfur Oil 6 Option - The operational choice of requiring low sulfur Oil 6 (0.5%) in place of high sulfur Oil 6 (2.2%) had the strongest and most consistent effect of all choices for the scenarios modeled. It produced a very large decrease in SO_2 emissions for a relatively low cost increase, with no other major effects. It was more effective in reducing SO_2 and had fewer countervailing tradeoffs than any of the supply-side technology choices, and worked well in combination with all of them.

High Target Reserve Margin Option - The choice of the higher 30% target reserve margin vs. the usual base 23% reserve margin basically increases reliability at only a marginal increase in cost. This option does increase the risk of rateshock, even if unit cost of service increases only a little, because the capital costs are front-loaded, while fuel savings due to increased efficiency are spread over the plant lives. Increasing the reserve margin had a slight, positive effect on air emissions. Although SO_2, CO_2, particulates and, to a greater extent, NO_x emissions decreased, the risk of greater local opposition to the additional plant sitings must be considered.

Taking an overall view of the choice by choice conclusions presented here, we see that the Coal Dependent, Coal & Repowering and Repowering supply-side option-sets are near the knees on the tradeoff curves most often. Combining these three technology-mix choices with the Enhanced Collaborative DSM option-set, greater use of low sulfur Oil 6, and a high target reserve margin appears to define the region where most of the larger tradeoffs occur. Although the analysis team cannot tell a consumer advisory group or COM/Elec what its preferences should be, these combinations point to an overall strategy with promising results.

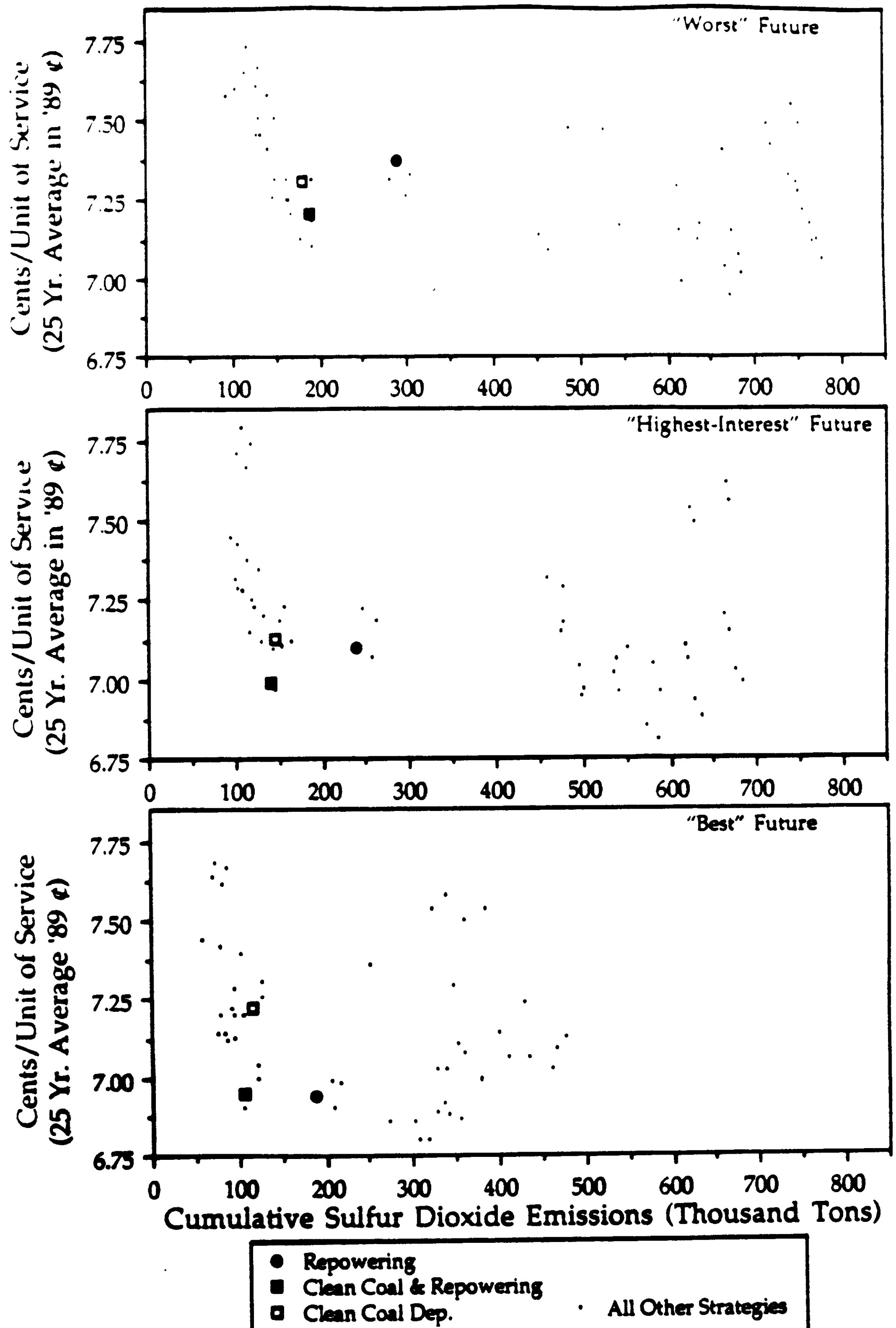
To illustrate these three strategies, four series of tradeoff graphs are shown below in Figures 7.1 through 7.4 for cost vs. rateshock, emissions, and reliability. These graphs show the tradeoff curves for the best, worst, and highest-interest futures, and highlight the Coal Dependent, Coal & Repowering and Repowering technology-mixes combined with Enhanced Collaborative DSM, low sulfur Oil 6 use, and 30% target reserve margin.

Figure 7.1 - Cost of Service vs. Rateshock



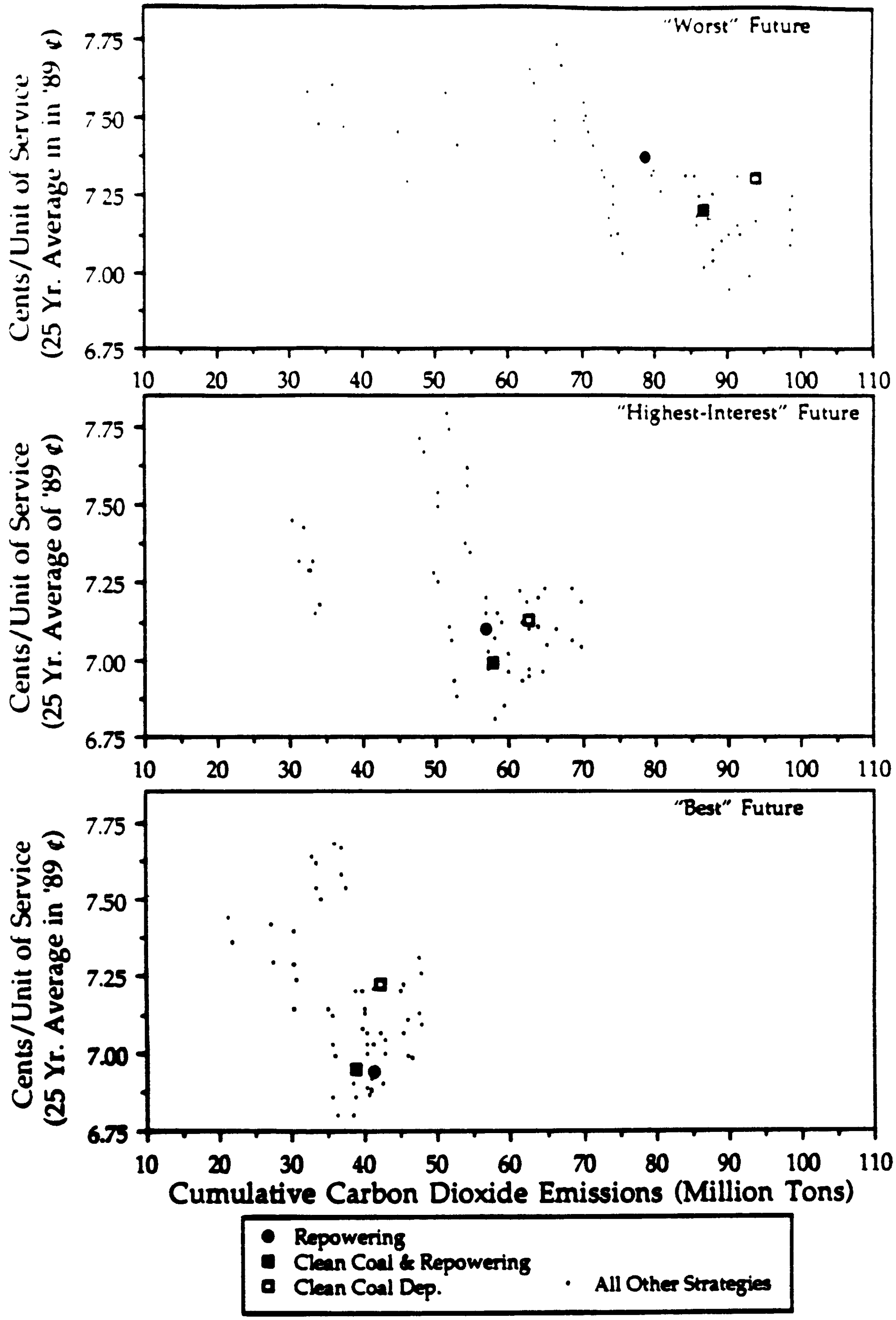
The preferred strategies have the above technology mixes along with Enhanced Collaborative DSM programs, Low Sulfur Oil 6, and a High Reserve Margin

Figure 7.2 - Cost of Service vs. Total SO_2 Emissions



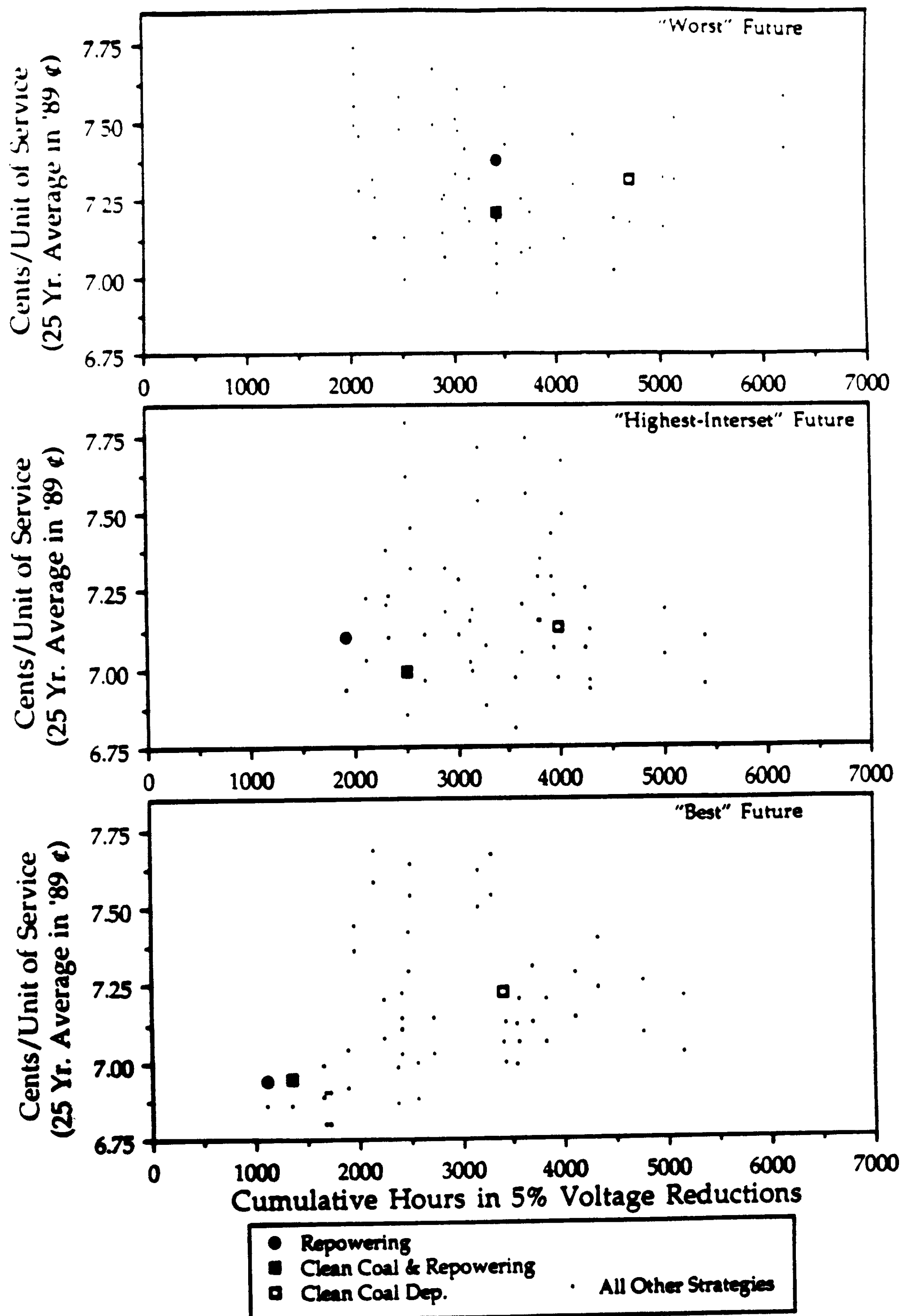
The preferred strategies have the above technology mixes along with Enhanced Collaborative DSM programs, Low Sulfur Oil 6, and a High Reserve Margin

Figure 7.3 - Cost of Service vs. Total CO_2 Emissions



The preferred strategies have the above technology mixes along with Enhanced Collaborative DSM programs, Low Sulfur Oil 6, and a High Reserve Margin

Figure 7.4 - Cost of Service vs. Total Hours 5% Voltage Reduction



The preferred strategies have the above technology mixes along with Enhanced Collaborative DSM programs, Low Sulfur Oil 6, and a High Reserve Margin

7.4 Comparisons with the New England Region

As mentioned in the introduction, the COM/Elec project is one of two ongoing projects being performed by the MIT Analysis Group for Regional Electricity Alternatives. The other project continues to study regional alternatives for all of New England, and exhibits some significant similarities and contrasts to the COM/Elec project. In particular, the inputs and results of the winter 1989-1990 round of analysis for the New England project differed in significant ways, yet produced the same general conclusions.

A number of contrasts between the two projects exist in the studies' input assumptions. On the supply-side, the New England project assumed repowering was more available and more expensive, Canadian power purchases were a major option, cogeneration was a relatively larger option, and units on new sites were limited to gas-fired technologies. On the demand-side, the New England project combined the same spectrum of program options, but with a much wider range of total impacts (15 option-sets versus just two). The chief difference was that the COM/Elec study included the option of requiring low sulfur Oil 6 for oil-fired generation.

Based on these differences, the quantitative . ults of the two studies were naturally different. In addition, the primary attributes chosen to study these options were different as well. The New England study focused on the total costs of providing electric service (which is largely driven by load growth), while the COM/Elec project focused on the total cost per unit of electric service provided. Both studies looked at total cumulative emissions of SO_2 and CO_2, but the New England study also looked at the number of new MW that would need to be sited under different strategies. Finally the COM/Elec study focused more on the issues o rateshock and reliability, and included measures of both these issues as primary attributes.

Given the differences in inputs and results, conclusions for both studies were still quite consistent, and include the following:

- Load Growth - In both studies, load growth is the primary uncertainty that drives total results, including SO_2 and CO_2 emissions, and total costs.

- Relative Impacts - Both studies also showed that supply-side option-sets had larger impacts on cost and emissions than DSM options. There is also a wider range of impacts between different supply-side options, whereas DSM options were consistent in the size of their impacts.

- Fuel Impacts - In both studies, gas-dependent strategies reduced SO_2 (and the related attributes of nitrous oxides and particulates emissions) more than they reduced CO_2 emissions, and these effects shifted in similar ways when the price of gas was high relative to oil.

- Demand Side Management - In both studies, increasing demand side management decreased CO_2 emissions but had mixed impacts on SO_2. In the New England project, high levels of DSM allowed higher SO_2 emissions since they inhibited construction of new, cleaner generating units. This effect was less evident for COM/Elec because the range of DSM options was smaller (only the Collaborative and Enhanced Collaborative programs). The Enhanced Collaborative programs were generally better, but their relative positions often changed for the worst futures where customer participation in utility sponsored DSM programs was low.

- Efficiency - In both studies, higher load growth and in the COM/Elec case, higher reserve margins increased the efficiency of generation and reduced emissions, due to lower relative use of older and dirtier plants. This effect was clearer for New England as a whole; for COM/Elec it was partially hidden by an inverse correlation between load growth and average reserve margin.

- Nuclear Tradeoffs - The nuclear option included in the COM/Elec study dominated the SO_2 vs. CO_2 emissions tradeoff where cost was ignored. This tradeoff was more gradual and shifted over more technology choices for the New England scenario set which included new generation from nuclear sources only as a component of the Canadian power purchases option.

7.5 Primary Project Conclusions

Open Planning Process Conclusions

As mentioned in the introduction, the initial project goals were for MIT to provide "integrated resource planning assistance" in order to "enhance their planning processes and develop a framework for useful public discussion of utility planning issues". Specific tasks included reviewing current planning methods, expanding the company's ability to function in open planning processes, developing their multi-attribute tradeoff analysis capabilities, performing public education on utility planning issues, and exploring issues relating to the interactions between the utility and the region.

The project has succeeded in meeting these goals and tasks. The project developed an open planning multi-attribute tradeoff analysis methodology. COM/Elec's current planning methods were reviewed, and the most suitable production costing model was chosen as the "analytic engine" for the process. The success in automating the modeling process meant that large numbers of runs could be performed in a reasonable amount of time, thereby allowing the feedback of results to the advisory group within a reasonable schedule of meetings.

The advisory groups were also successful in educating people about the complexities of the utility planning process and exploring the issues that concerned them. Beyond these initial goals the groups were able to form a limited consensus on some of the resulting tradeoffs and indicated directions for further analysis. This initial experiment with open planning had success in getting public input for prioritizing issues and assessing risk aversion, but had mixed success in achieving consensus on specific planning choices. Where all-gain (or win-win) outcomes were revealed, such as with greater amounts of DSM and higher reserve margins, consensus was possible. Where tradeoffs had to be made, it was more difficult. Both more time and analysis (of hybrid strategies) were needed. The process certainly inspired both the participants and analysts to suggest improved hybrid strategies, such as clean coal with repowering and low sulfur oil, plus high DSM and higher reserve margins. As such, it played a vital role in spurring inventiveness in the planning debate, and in improving communications between COM/Elec customers and staff on long-term issues, but did not reach closure on decisionmaking. The advisory group did come to appreciate the value of developing integrated, robust strategies based on system-wide analysis, rather than a limited evaluation of supply-side or demand-side options, based solely on their individual characteristics.

Group participation was also a mixed success. COM/Elec was successful in attracting participants from different consumer sectors and interests who were community activists and decision makers of the type who might be expected to participate in future planning or rate case hearings. Unfortunately, the number of participants who actually attended was lower than desired, and dropped off for the second and third meetings. The consumer advisory groups were too small and too narrowly selected to be able to claim that they were representative of general public opinion (this was not even an original goal). This demonstrated the conflict between the time required for quality public participation and the number of people who could make the necessary, continuing time commitment. More time was needed to evaluate customer feedback, such as the new hybrid planning options suggested based on results presented at the third meeting. However, during actual use of the open planning process in the regulatory setting it seems likely that any interest groups who could offer sustained interventions and opposition would also have the most interest in contributing to the open planning process with sustained participation.

However, given the attendance, the response of participants was positive and enthusiastic. The meetings proved that the process of educating participants to the complexities of utility planning problems, obtaining their concerns, and conveying back to them credible and understandable results was readily possible. The participants came away appreciative of the complexity of certain problems, and understanding that both win-win and tradeoff situations could result from the choice of planning options. The good-will and enthusiasm generated in those participants who were able to attend all three meetings bode well for future use of open planning techniques in the regulatory process. Many of the advisory group members urged that the open planning process should be continued beyond this initial phase.

Technical Analysis Conclusions

These results of the COM/Elec project combined with those of earlier New England project results to confirm two overarching conclusions. First, that there must be a balanced consideration of generation and end-use options if competing goals of cost, reliability and environmental quality are to be achieved. Strategies that push exclusively either supply-side or demand-side options may lose out in the overall, long-range picture.

Second, strategies need to be judged based on their systemic interactions, rather than on a option-by-option technology basis. Externality adders or other judging schemes that work on a technology or option specific basis may miss interactions between the existing plant base, the combination of new technology choices, and different planning and system operation options.

In addition, the COM/Elec project adds a third major conclusion. By showing the major effects which burning low sulfur Oil 6 can produce, it shows that to develop a balanced, systemic point of view, we must look beyond the choice of new supply and demand technology options to include system operation choices. Effective utility planning requires more than determining what kind of new capacity to build, and how much can be saved by various demand-side measures. It must also include how the system is operated. Decisions such as unit-fueling and alternate dispatch order can carry significant risks and opportunities.

7.6 Possibilities for Future Analysis

Future applications of the open planning process by COM/Elec will depend upon the utility's concerns and upon the concerns voiced by different groups in future external consumer advisory groups. However, based on the results explored in this chapter, some areas of interest appear to be likely candidates for future investigation.

First, diversify the utility's fuel mix from current dependence on Oil 6 fired units as base load capacity. Current technology options for new units did not displace the Canal plant from base load operation under the Oil 6 price forecast used. The low sulfur Oil 6 option analyzed in this study emphasized the large benefits of reducing (SO_2) emissions from the Canal plant, but the only other alternative analyzed for refueling this plant with a different type of fossil fuel (coal gas) was far too expensive. A clean, low cost base-load option could have a large impact, but given the high efficiency of the Canal plant, it would require an exceptional option to compete with it.

Second, the current set of scenarios were limited to consideration of the fuel price sensitivity as natural gas shifted relative to oil. A wider range of oil price uncertainties would better reveal the costs and benefits associated with a shift away from Oil 6 a base load fuel, and all the effects which this would imply. This question would obviously complement with the first suggestion given just previously.

Third, COM/Elec was modeled in this study as a stand alone utility, independent of the surrounding power pool. Some aspects of this interaction can be simulated by adding input assumptions to the model used, including the availability of power interchanges, and how the relative age and efficiency of COM/Elec's plant base relative to the region's would influence such interchanges. Other aspects of power pool interactions can be studied by comparing pool results to stand-alone COM/Elec results for scenarios more comparable than those results for the COM/Elec and New England projects given above. However, true modeling of utility/pool interactions requires geographic specificity and transmission constraints which are beyond current capabilities. This area is one which is seen as a key area of research for the New England region as a whole.

Appendix A – List of Advisory Group Participants by Role

COM/Electric Open Planning Project Participants

Cambridge	Accepted Invite	1st Meeting	2nd Meeting	Question-naire	3rd Meeting
	Attendance Record				
State Senator, Cambridge					
Facilities Manager (*attended New Bed.) Polaroid Corporation	√	√	√*	√	√*
Chairperson Neighborhood Nine Association	√				
President Dole Publishing					
Manager of Physical Plant Harvard University	√		√	√	√
Director of Community Relations Harvard University	√	√			
Chairman Cambridge Chamber of Commerce	√	√	√	√	
City Planner Community Development Department City of Cambridge	√	√			√
Energy Planner	√	√			
Associate Director of Physical Plant Massachusetts Institute of Technology	√	√	√	√	√
State Representative, Cambridge	√	√			
Chairperson Hastings Square Neighborhood Associat'n	√	√	√	√	√
Cambridge Totals	10	8	5	5	5

COM/Electric Open Planning Project Participants, cont'd.

Plymouth	Attendance Record: Accepted Invite	1st Meeting	2nd Meeting	Question-naire	3rd Meeting
Executive Director, South Shore Community Action Council	√				
Executive Director, Plymouth County Development Council	√				
Chairman/(Alt.-City Planner) Plymouth Board of Selectmen	√	(√)	(√)	(√)	
President MPG Communications (Newspapers)	√	√	√	√	√
President WATD Radio Station	√		√	√	√
Chief Executive Officer Cordage Park Company	√				
Representative Plimouth Plantation	√				
Banker, Plymouth	√				
State Representative (Alt.- Aide) Wareham	√	√	(√)	(√)	
State Representative, Plymouth					
President Plymouth Federal Savings Bank	√	√			
Selectman Board of Selectmen, Bourne					
Plymouth Totals	11	4	4	4	2

COM/Electric Open Planning Project Participants, cont'd.

Hyannis	Attendance Record: Accepted Invite	1st Meeting	2nd Meeting	Questionnaire	3rd Meeting
Speaker Assembly of Delegates Barnstaple County	√				
Executive Director (Alt.- Planner), Cape Cod Planning and Develop't Commission	√	(√)			(√)
President Cape Cod Hospital	√	√			
General Manager Cape Cod Mall	√				√
Executive Director Cape Cod and Island Board of Realtors	√		√	√	√
Owner Puritan Clothing	√	√			
State Senator, Hyannis	√	√			
Aide to State Senator, Hyannis		√	√	√	√
Publisher Cape Cod Times					
President Radio Station WOCB	√				
Executive Director Cape Cod Chamber of Commerce		√			
Executive Director Association for Preservation of Cape Cod			√	√	
President Cape Cod Bank & Trust Company	√	√			
County Commissioner Barnstaple County	√		√	√	√
Hyannis Totals	10	7	4	4	5

COM/Electric Open Planning Project Participants, cont'd.

New Bedford	Attendance Record: Accepted Invite	1st Meeting	2nd Meeting	Question-naire	3rd Meeting
Editor New Bedford Standard Times	√			√	
Editor/(Alt.-Reporter) The Portuguese Times Newspaper		(√)			
President Acushnet Company	√	√	√	√	
Executive Secretary Fairhaven Town Hall	√	√		√	√
State Senator, New Bedford					
Manager, Public Works Department Town of Dartmouth	√				
General Manager Whaling City Cable TV		√	√	√	
President New Bedford Institution for Savings					
Chairman United Way of Greater New Bedford	√	√			
Mayor (Alts.- City Planners) City of New Bedford		(√)	(√)	(√)	
Chairman Bristol County Development Council	√	√			
Selectman Town of Freetown		√	√	√	
Owner/Editor The Cape Verdean Newspaper		√	√	√	√
Cranberry Grower		√			
New Bedford Totals	6	10	5	7	2
Anonymous				1	

Appendix B – Attribute Definitions

Attribute Calculations

Attributes are calculated from LMSTM input and outputs, and from PSP summary planning information. The following attributes are defined in the order in which they are presented in the final Systat database, along with their abbreviations and units.

Total Cost of Service: Net present value of revenue requirements stream discounted at 12.813%. (TCOST, Millions of Constant 1989 Dollars)

Undiscounted Cost of Service: Sum of annual revenue requirements, discounted at the assumed rate of inflation (5%). (UTCOST, Millions of Constant 1989 Dollars)

Average Revenue Requirement: Previous attribute divided by 25 (the number of years in the study period. (ARR, Millions of Constant 1989 Dollars)

DSM Investment: Net present value of stream of DSM investments, discounted at 12.813%. (DSMINV, Millions of Constant 1989 Dollars)

Supply Investment: Net present value of capital costs for new utility-owned plants (excludes cogenerators). (SSINV, Millions of Constant 1989 Dollars)

Cogeneration Investment: NPV of investments in cogeneration plants. (COGINV, Millions of Constant 1989 Dollars)

Average Unit Cost of Service: Real (inflation adjusted) annual revenue requirements divided by unadjusted (no DSM) energy sales. This attribute is thus a measure of the cost of prc :ding energy services, not just kWh. (UCS, 1989 ¢/unit of electric service provided by one kWh in 1989)

UCS Standard Deviation: The standard deviation in the stream of annual UCS values. (UCSSD, standard deviation in 1989 ¢/unit of electric service)

Maximum Annual Percentage Increase in UCS: Maximum of [[(UCS in year i+1) - (UCS in year i)]/(UCS in year i)] * 100, a measure of volatility in consumer bills. (UCSMAX, percent)

Total Pollutant Emissions: For each power plant group, FPROC generates annual emission rates for each pollutant in lb/MWh. These values are multiplied by annual generation by group. The resulting stream of annual values is converted into more manageable units (yielding the pollutant trajectories) and summed without discounting. Individual pollutants, their abbreviations and units are listed below

Sulfur Dioxide - SO_2 .... (SO2, thousand tons)
Nitrous Oxides - NO_x .... (NOX, thousand tons)
Carbon Dioxide - CO_2 .... (CO2, million tons)
Total Suspended Particulates .... (TSP, thousand tons)
Nuclear Waste .... (NUCWST, tons)

OP-4 Hours: Each of the OP4 levels is modeled as a separate "reliability generator." The (fictitious) energy generation by these units is divided by their MW capacity, yielding the number of hours that the system was in the given OP4 level.

OP-4, Actions 1 & 2 .... (OP1_2, hours)
OP-4, Actions 8 & 9 .... (OP8_9, hours)
OP-4, Action 13 .... (OP13, hours)
OP-4, Action 14 .... (OP14, hours)
OP-4, Action 15 .... (OP15, hours)

Unserved Energy: The total number of GWh that the system was unable to provide, once the reliability generators were exhausted. (UNSGWH, Gigawatt-hours GWh)

Total Service Shortfall: Sum of OP4-8/9 through unserved energy. This attribute represents an equivalent of total unserved energy in hours. This measure double counts outage hours where more than one of the virtual OP-4 'generators' is operating. This weighting serves as a proxy for the increasing severity of the OP-4 action levels. (SRVSHTFL, hours)

Total Energy Sales: Sum of the 25 annual values reported by LMSTM. (TTWH, Terawatt-hours TWh)

Total Conserved Energy Sales: A trajectory of energy sales from an LMSTM run with no DSM is pasted into the spreadsheet and the scenario-specific energy sales are subtracted. The difference is a stream of energy savings, which is then totaled. (TDSM, Megawatt-hours MWh)

Maximum Peak Reduction: A stream of peak reduction values is calculated in the same way that energy savings are. The value reported here is the maximum of that stream. (MAXPR, Megawatts MW)

Demand-Side Efficiency Improvement: Annual energy savings are divided by annual sales to determine the percentage savings in each year. Demand efficiency improvement is the maximum of that stream. We chose to use the maximum because DSM measure effectiveness decays with time. If one assumes that a market transition towards more energy efficient appliances, water heaters, etc. will have occurred by the time that measures wear out, demand efficiency will continue to increase, or at least remain stable. (DSMEFF, percent)

Supply-Side Efficiency Improvement: Percentage improvement of system heat rate between the first and last years of the study period:

$$\left(1 - \frac{[\text{Total BTU content of all fuel in year 25/kWh sales in year 25}]}{[\text{Total BTU content of all fuel in year 1/kWh sales in year 1}]}\right) * 100$$

(SSEFF, percent)

Cumulative Fossil Heat Rate: Sum of all fossil BTU's consumed divided by total fossil kWh generation. (FHR_CUM, Btu/kWh)

Average System Heat Rate: Total BTU input from all fuels divided by total kWh sales. (SHR_AVE, Btu/kWh)

System Efficiency Improvement: Combines demand and supply efficient improvements:

$$(1 - (1 - \text{Supply Eff. Improvement}) * (1 - \text{Demand Eff. Improvement})) * 100$$

(SYSEFF, percent)

Energy Content of Fuel Consumed: Each FPROC file contains a stream of annual heat rates for each group. These are multiplied by annual group generation yielding BTU consumption by group. These streams of annual BTU consumption are totaled and then aggregated by fuel type. Because combustion turbines and combined cycle plants use gas or kerosene depending on the season, BTU input is calculated seasonally for these plants. (all units are in Millions of MMBtu, one MMBtu is a million Btu's)

Oil 6 - 0.5%.. (OIL6_0.5)
Oil 6 - 1.0%.. (OIL6_1.0)
Oil 6 - 2.2%.. (OIL6_2.2)
Kerosene .... (KERO)
Diesel .... (DIESEL)
Slice of Northeast Utility System .... (SLICE)
Cogeneration Units .... (COGEN)
Nuclear... (NUCLEAR)
Natural Gas .... (NATGAS)
Coal .... (COAL)

All Oil 6... (OIL6_ALL)

All Fossil Fuels.. (FOSS_ALL)

Final Reserve Margin: (RM_FINAL, percent)

Average Reserve Margin: (RM_AVE, percent)

Minimum Reserve Margin: (RM_MIN, percent)

Number of Years Below Target Reserve Margin: (RM_BEL)

Number of Years Below 20% Reserve Margin: (RM_20)

Number of Years Below 18% Reserve Margin: (RM_18)

Number of Years Below 16% Reserve Margin: (RM_16)

Number of Years Below 14% Reserve Margin: (RM_14)

Number of New Units by Technology:

Combustion Turbines............................... (CT_NO)
Combined Cycles....................................... (CC_NO)
Coal Gasification Combined Cycle......... (CGCC_NO)
Advanced Light Water Reactors............. (ALWR_NO)

Total Number of New Units: (Total_NO)

Megawatts of New Units by Variable Ratio Technology:

Combustion Turbines............................... (CT_MW, MW)
Combined Cycles....................................... (CC_MW, MW)
Coal Gasification Combined Cycle......... (CGCC_MW, MW)
Advanced Light Water Reactors............. (ALWR_MW, MW)

Total MW of New Variable Ratio Units: (RATIO_MW, MW)

Total MW of New Fixed MW Units: (FIXED_MW, MW)

Total MW of New Units: (TOTAL_MW, MW)

Total Acres Required by New Units: (ACRES, ACRES)