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Regional Power Systems Planning; A State of the Art Assessment

Final Report

October 1980

Prepared for:

U.S. Department of Energy

Assistant Secretary for Resource Applications

Office of Electric Energy Systems

Under Contract No. AS05-77ET29144

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Prepared by:

The University of Oklahoma

Norman, Oklahoma 73019

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FOREWORD

As societal systems have grown larger and more complex, there has been growing interest in regional planning. In as much as electric energy is highly correlated with the output of goods and services of any region, regional power systems planning is of interest. Particularly of interest to the Division of Electric Energy Systems are the tools and methods available which may be needed for conducting such planning.

Accordingly, the purpose of this report was to define regional power systems planning problems, the tools available and their shortcomings, and to document all of the above in a concise readable form.

Our approach consisted of a survey and literature search. The survey determined the tools being used by utilities, the tools they had rejected, and the tools they planned to try out. The literature search was conducted for the purpose of documenting the tools available, and performing a comparative analysis of these tools. The project included a mix of utility, university, and consulting organi-

zations. Several organizations were consulted in the selection of the participants. A non-profit organization, The University of Oklahoma, was selected to manage the project. The results were reviewed in a series of four one day meetings by known authorities in each field.

This report consists of the results of this project. Perhaps its major finding is that several aspects of the regional planning problem are not well defined, the roles of the various participants in regional planning is not clear, and certainly research is needed for the development of new methodology.

We hope this report will be useful to the research community developing the methodologies required, and to academicians and utility engineers in selecting and better understanding the methodologies available. We also hope it will serve as a catalyst for moving power system planning nearer to regional planning.

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SECTION 1.

THE NEED FOR REGIONAL PLANNING METHODOLOGY

INTRODUCTION

There is no basis for regional planning, that is, planning where two or more utilities join in common research and develop expansion or reduction plans which are coordinated, unless there is a demonstrated common interest in coordination on a regional basis, and a set of environmental circumstances which render plans and methods used in one area invalid in another area.

First, there are major differences among regions where natural interest groups have formed. Tables I and II show developed and undeveloped hydroelectric power available in different regions in the United States. The North Pacific area has more than eighteen times as much hydroelectric potential as does the lower Mississippi, for example. Clearly, generation expansion alternatives will differ markedly in these two areas. The ability to meet Federal air quality regulations will differ significantly and different planning approaches and levels of methodology would be dictated.

Population densities vary significantly (see Table III). This will have a clear impact on transmission and distribution in these regions. The availability of coal is another example (see Table IV). The New England area is significant by its lack of this important resource. In some regions, transportation problems will dominate planning, while in other areas on mine site generation of electricity will focus planning problems on air quality, water pollution, ground water contamination, and strip mine reclamation problems. Unusual energy sources such as tides and wave action are available only on the coastline as is much of the geothermal potential. Thus natural resource differences dictate opportunity and types of cooperation.

Natural interest groups do exist. Some of these may be forced by groups of states joining in bodies to regulate energy development. This regional context of energy development is documented in (1). Regional Reliability Councils exist now to coordinate activities among utilities so that reliability of the power supply is increased (see Figure 1). Many major power pools already exist among contiguous service area (see Figure 6).

The federal government divides the country into regions for the purpose of national power surveys, again implicitly recognizing the regional nature of electric power supply problems (see Figure 3).

Thus, the regional nature of electric power supply problems is recognized by both the utilities and the public sector.

REGULATORY IMPACT OF GOVERNMENT AGENCIES

State and federal governments have proposed far reaching regulations of the electric utility industry. Every area of utility electric power generation is covered. Laws have been proposed to mandate higher prices during peak loads, requiring incremental cost pricing, requiring higher rates for large users, (inverted rate structure), requiring low rates for the poor or elderly, restricting bulk metering, prohibiting electric resistance space heating, prohibiting fuel adjustment pricing, requiring load management practices, and enforcing certain rate differentials (8). If any of these bills became law, much planning that has been completed will be invalidated and new planning must account for these requirements. Clearly demand, future costs and operating practice would be drastically affected. Can current planning methods assess the impact of these laws on a regional basis?

More than pricing is affected. In Alaska assets of a utility could be transferred to a regulatory authority, in Delaware mandated investment policies are proposed, in California certain pipeline routes are abolished in one proposed law, in Oregon disposal sites for nuclear materials are to be banned, in Minnesota new red tape requirements for large energy facilities are proposed, in New York reclamation of used oil would be required plus new surface mine regulations. In the Senate a law mandating use of gasohol has been proposed. Can regional planning now assess the impact of operating restrictions such as these? (6)(9)

In Oklahoma, as elsewhere, it is clear that no evaluation of the cost of obeying regulations is computed, nor is the lead time known to implement regulations (7). Can regional planning be done without this data?

It is already clear that mandated environmental constraints vastly increase the capital cost of large energy facilities (5). Do current planning methods allow a clear assessment of the socioeconomic impact of proposed regulations? (5)

TABLE I - CONVENTIONAL HYDROELECTRIC POWER IN THE UNITED STATES
DEVELOPED, UNDEVELOPED, AND TOTAL POTENTIAL - JANUARY 1, 1976

Major Drainage	Developed			Undeveloped			Total Potential		Percent Total Potential Cap. Now Developed
	No. of Plants	Installed Capacity KW	Average Annual Generation 1,000 KWH	No. of Sites	Installed Capacity KW <u>1/</u>	Average Annual Generation 1,000 KWH	Installed Capacity KW <u>1/</u>	Average Annual Generation 1,000 KWH	
North Atlantic	247	2,712,078	10,919,796	174	7,131,791	18,299,641	9,843,869	29,219,437	27.6
South Atlantic	93	3,412,739	7,467,785	85	4,283,731	8,137,954	7,696,470	15,605,739	44.3
Eastern Gulf	39	2,370,653	7,166,003	55	2,733,140	4,036,770	5,103,793	11,202,773	46.4
Ohio	82	5,123,842	21,616,522	81	4,596,170	14,347,078	9,720,012	35,963,600	52.7
Great Lakes St. Lawrence	262	4,008,191	24,754,252	99	1,304,290	3,757,800	5,312,481	28,512,052	75.4
Hudson Bay	5	13,600	68,000		0	0	13,600	68,000	100.0
Upper Mississippi	106	581,420	3,006,279	38	588,150	2,537,364	1,169,570	5,543,643	49.7
Missouri	66	3,369,653	15,293,561	138	5,485,610	18,996,624	8,855,263	34,290,185	38.1
Lower Mississippi	27	2,044,510	5,442,900	58	2,167,800	4,458,460	4,212,310	9,901,360	48.5
Western Gulf	21	458,238	1,307,540	50	1,261,085	2,308,750	1,719,323	3,616,290	26.7
Colorado	43	3,206,308	12,174,530	61	2,052,240	8,503,000	5,258,548	20,777,530	61.0
Great Basin	73	352,914	1,342,200	21	425,438	976,700	778,352	2,318,900	45.3
North Pacific	164	22,342,238	127,182,300	518	38,920,285	113,511,784	61,262,523	240,734,084	36.5
South Pacific	149	6,897,017	32,784,700	150	9,422,580	27,972,000	16,319,597	60,756,700	42.3
Alaska	31	123,167	493,345	89	33,282,950	175,796,800	33,406,117	176,290,145	0.4
Hawaii	15	18,152	104,400	2	35,000	229,000	53,152	333,400	34.2
Total United States	1426	57,034,720	271,124,113	1619	113,690,260	404,009,725	170,724,980	675,133,838	33.4

1/ Includes Potential Capacity Additions or Subtractions at Existing Plants

Source: "Hydroelectric Power Resources of the United States, Developed and Undeveloped", January 1, 1976,
p. xii, F.P.C., Washington, D.C.

TABLE II - CONVENTIONAL HYDROELECTRIC POWER IN THE UNITED STATES
DEVELOPED, UNDEVELOPED, AND TOTAL POTENTIAL - JANUARY 1, 1976

Geographic Division	Developed			Undeveloped			Total Potential		Percent Total Potential Cap. Now Developed
	No of Plants	Installed Capacity KW	Average Annual Generation 1,000 KWH	No of Sites	Installed Capacity KW 1/	Average Annual Generation 1,000 KWH	Installed Capacity KW 1/	Average Annual Generation 1,000 KWH	
New England	220	1,506,462	6,046,791	113	3,274,231	7,542,441	4,780,693	13,589,232	31.5
Middle Atlantic	154	4,231,739	25,454,337	106	4,298,010	12,309,478	8,529,749	37,763,815	49.6
East North Central	210	925,594	4,415,433	81	1,358,250	5,364,564	2,283,844	9,779,997	40.5
West North Central	74	2,771,143	11,835,119	78	2,135,770	5,810,224	4,906,913	17,645,343	56.5
South Atlantic	160	5,794,744	15,717,406	152	8,367,861	18,607,074	14,162,605	34,324,480	40.9
East South Central	55	5,460,412	21,635,312	58	3,127,260	6,244,450	8,587,672	27,879,762	63.6
West South Central	40	2,255,130	6,078,840	82	2,722,285	4,506,250	4,977,415	10,585,090	45.3
Mountain	176	6,879,707	31,036,880	354	19,622,069	66,621,148	26,501,776	97,658,028	26.0
Pacific	291	27,068,470	148,306,250	504	35,466,574	100,978,296	62,535,044	249,284,546	43.3
Alaska	31	123,167	493,345	89	33,282,950	175,796,800	33,406,117	176,290,145	0.4
Hawaii	15	18,152	104,400	2	35,000	229,000	53,152	333,400	34.2
Total United States	1426	57,034,720	271,124,113	1619	113,690,260	404,009,725	170,724,980	675,133,838	33.4

1/ Includes Potential Capacity Additions or Subtractions at Existing Plants

Source: "Hydroelectric Power Resources of the United States, Developed and Undeveloped", January 1, 1976, p. xii, F.P.C., Washington, D.C.

TABLE III

New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain Area	Pacific Area
188.1	670.8	164.9	32.1	114.9	71.5	45.2	9.7	29.7

(Population per square mile of land area)

Source: "Statistical Abstract of the United States", 1977, p. 12-13, U.S. Department of Commerce, Bureau of the Census.

TABLE IV

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain Area	Pacific Area
Reserves Thousand Tons	0	23,880,100	97,482,800	30,191,300	44,182,400	29,509,100	5,135,400	185,358,800	13,601,200
Production Trillion BTU	0	2,149.9	2,993.7	235.5	3,710.3	4,200.3	172.4	1,391.9	91.7

(Coal)

Source: "Fuels and Energy Data: United States by States and Census Divisions", 1974, p. 23-31, Bureau of Mines Information Circular/1977. United States Department of the Interior.

Figure 1
Regional Reliability Councils (2)

Figure 2
Major Power Pools (3)

Figure 3
National Power Survey Regions (4)

What is the effect of frequent changes in regulatory policy? Can regional planning on a long term basis even be accomplished? These are substantive questions that require a thorough assessment of planning practice and theory at the regional level to determine if a need exists for a research effort in planning methodology.

THE PLANNING PROCESS FOR REGIONAL PLANNING

The planning process at the regional level will differ from single utility planning in a variety of ways. The prime differences will be in the policy questions analyzed, the need for including coordination of generation and transmission activities among utilities in the analysis, and the multiplicity of governmental bodies that must be satisfied. The following outline of the planning process is general in scope. It is a distillation of the results from the industry survey, principles used in analysis by sub-contractors and research by The University of Oklahoma staff.

The Planning Process

1. Determination of need for system expansion/reconfiguration.
Projections: a) demand forecast (aggregate)
b) demand sector location
c) timing of peak load and its magnitude in each sector
2. Determination of the timing and nature of submissions for each required regulation body.
a) determination of planning decisions affected
b) determination of evidence required
3. Development (choice) of objectives to be satisfied by the plan
4. Development (choice) of measures of effectiveness of plans relative to objectives
5. Definition of constraints
6. Development of method of computing overall effectiveness of plans considering all objectives and constraints
7. Development of alternative plans to coordinate decisions on:
 - a) new facility location
 - b) fuel sources
 - c) prices and price structure
 - d) power pool agreements
 - e) peak load control mechanisms
 - f) transmission routes
 - g) environmental controls used
 - h) methods to accomplish reliability (redundancy, higher quality parts, increased maintenance, etc.)
8. Choice of the overall most effective plan

Each step in this process defines either a need for a model, for data, for governmental specification of requirements, or for inter-industry agreement on goals, objectives and measures. The state of the art in regional planning can be judged by how effectively this outline can be followed by practicing planners today. The question is: does there exist the data, the models, the decision rules to carry out steps 1-8 of the planning process? The work of the subcontractors in the four areas of generation, transmission, energy models, and systems and processes forms the data from which this question can be answered.

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SECTION 2.

ANALYSIS OF THE UNIVERSITY OF OKLAHOMA INDUSTRY SURVEY

In the latter part of 1977, a survey was made to locate as many existing models that have been used in connection with regional power systems planning as possible. A detailed survey was mailed to 200 different institutions made up of the following groups: (A) Utilities, (B) Consultants and Manufacturers, (C) Regional Groups, Federal Power Agencies and Institutional Researchers, (D) Universities, (E) Foreign Institutions.

A total of 74 responses were received for a return of 37%. This response gives us a reasonably good sampling of all 5 groups mentioned above and gives one a good picture of what has occurred in the planning area over the last decade or more. The survey has been produced and published by the Department of Energy and is available through the National Technical Information Service of the U.S. Department of Commerce. The order number for the document is HCP/T-5468/1. The survey will not be described in great detail here since it is available through the NTIS. However, it is germane to this report to summarize the results of the survey both in qualitative terms and in terms of the characteristics of the responses.

While there is considerable overlap in the responses, even after they have been examined by the investigators, the resulting number of model descriptions is informative. The survey was made in terms of three categories. These include generation models, transmission models, and energy supply/demand models. In these categories there were 147 models for generation planning, 216 models for transmission planning and only 70 models for energy supply/demand planning. Again, we note that there is considerable overlap in some of these, so that these numbers should be viewed in only a relative sense. Recognizing this fact; it becomes obvious that the bulk of the planning effort to date has gone into generation and transmission, with transmission being the larger of the two.

This may be seen also in the bar graphs of Figures 1, 2, and 3. These give some very interesting results. For example, one notes that transmission modelling activity rose in quantity at a considerably earlier date than the other two categories. It reached a peak in 1971 and, for a while thereafter, declined in activity. Of late, however, it appears that transmission modelling activity, is again on the rise. If one compares

this to generation modelling activity, he finds that there has been a steady growth in generation modelling since the mid 1960's. Examining the energy/demand modelling activity, one finds that only little activity occurred prior to the 1970's. There has been an extreme growth in this activity since 1973, as indicated by the survey results shown in this figure.

Perhaps the most interesting feature of these graphs is the peak in transmission modelling near 1971. One might be tempted to relate this peak in modelling activity to some economic factor or factors in our society that impinge upon the industry. However, one does not note a similar peak effect in generation planning, which would be assumed to be equally affected by such factors. It may be that, since the activity in transmission modelling began in a somewhat earlier period, that its further increase was impeded by a lack of adequate modelling approaches and computational techniques. The continued rise in generation modelling, the renewed rise in transmission modelling, and the rapid rise of energy supply/demand modelling, all occurring in the last four to five year period are probably due to the application of a new computational and modelling approach, rather than to economic factors. This may be questionable in the case of the energy area since certainly the Arab oil embargo and the subsequent drive toward energy independence has lead to a great amount of activity in this area.

Without going into the details of the models nor making judgments about relative capability nor value of the models, one can classify the areas of models which have been most widely or most popularly used. In the generation area, these are in the areas of production costing, generation expansion, and loss of load probability. There are, of course, many other types of models that have been used, ranging from the probability of forced outage to the effects of distributed solar/thermal generation. In the transmission area the most popular types of models have been those related to load flow and those related to systems stability. Again, there have been many other types of models used in this area just as in the generation area. Since the energy supply/demand modelling activity has been done in primarily the last four years, it is difficult to attach a popularity figure to any one particular sub area. The models are wide ranging and include not only fuels, but such items as effects of weather, residential sales, etc. The

approaches may be purely econometric in nature or may in some cases be more closely related to the system characteristics.

In looking at the survey as a whole, one can draw a reasonably clear conclusion about regional planning. First, the development of modelling in the transmission and generation areas has been prolific, but the models generally do not lend themselves to regional application. On the other hand, the energy supply/demand models have by and large been applied on a more national scale. Thus, once again, only a few cases include application to regional problems. One could combine these two facts into a single statement and say that modelling as a whole has been on two extremes, either the local level, as in the case of generation and transmission, or the national level, as in the case of energy. There seems to be a need for bringing these two extremes together at the regional level. This may be done by applying existing models, extending those models, or it may require a new set of approaches that are unique to the regional planning problem.

SECTION 3.

CONTRACTOR'S REPORTS

INTRODUCTION

The following is the main body of the report. It consists of four sections: Generation Planning, Transmission Planning, Energy Models and Systems and Processes. In each section is a summary of contractor efforts to assist the reader in finding

material pertaining to his own interests followed by the analysis and discussion sections of the respective contractors in the area. The appendices of each contractor, which contain the data and details substantiating the conclusions of the contractor are placed in the appendix section of this report by area and contractor.

SECTION 4.

GENERATION

The Philadelphia Electric Company report is a narrative description of present practice in generation planning. It is general in nature, in that no specific models are mentioned except by reference; only techniques are discussed. There are eight appendices to the report, and 29 references are provided.

The report begins with a discussion of the planning process, wherein the different points to be considered are brought out. Two items, limited energy generation, and optimal mix are covered in more detail in Appendices A and B of the report.

A discussion of reliability follows, in which the need for reliability is established, and the desirability of an appropriate reliability index is shown. Four different methods of calculating such an index are discussed. Two of these indexes, loss of load probability, and frequency and duration are explained in detail in Appendices C and D of the report.

Economic aspects are discussed next. Revenue requirements are broken down into three principal components, capital costs, production costs and operating and maintenance costs. Carrying charges are described as they apply to capital costs. Three different methods of estimating future production costs are presented. They are deterministic load duration, simulation, and probabilistic load duration. The first and third of these are covered in more detail in Appendices E and F of the report.

A discussion of environmental impact assessment is next. Here the different environmental factors to be considered are pointed out, with some mention of the availability of computer programs to assist in the evaluation. An overall technique for assessing alternate sites is provided in Appendix G of the report.

Corporate finance considerations are covered next. It is pointed out that though the planning may be regional, the corporate effects must be analyzed singly, by each utility, to assess its capital funding requirements, its cash flow situation and its tariff requirements. Some existing models are referenced, with strengths and weaknesses pointed out. It is mentioned that in an increasing number of cases financial models are being combined with other models into integrated forecasting systems. One corporate finance model, extracted from a reference, is described in Appendix H of the report.

The last discussion section covers automated planning. The principal objectives of automated planning are: (1) to provide an efficient means for screening the possible alternatives available for long-range system development, and (2) to assist in the short-range optimization of the choice and timing of generation additions from among specified candidates. Techniques to accomplish each of these objectives are discussed in general, and references are supplied. A case is made for an interactive planning method, at least in the short-range task of the second objective.

The University of Michigan report provides a survey of power generation methodology in narrative form. Specific models are mentioned only by reference to source documents. The report has five appendices and provides 28 references. The generation planning problem is placed in a regional context by focusing on methods appropriate to large scale power systems.

The report defines generation planning as follows: "Generation planning serves to identify the technology, size and timing of the next few generating plants to be added to the power system". It adds that the objectives are to assure that capacity is sufficient and that costs are efficient. The mix of plant type and the size and timing of individual units are discussed. It is pointed out that although reliability and cost are important, they are not the only relevant issues. There is substantial two-way influence between the generation planning problem and six other planning functions. These are transmission, environmental, financial, fuels supply, operations and R&D.

Generation planning methodologies are discussed next. It is stated that regardless of the tools or methods used, the planning is a two phase process: synthesis, followed by analysis. Among the synthesis methods available are expert judgment, target plant mix models, and computer based mathematical programming models. All of these have the function of reducing the virtually infinite number of possible expansion configurations to a small subset of economically efficient guideline plans. These then serve as input to analysis or simulation models for more accurate representations of system reliability, individual plant operation, and capital/production cost cash flow.

Simulation models are then discussed in more detail. Loss of load probability and installed reserve capacity are both mentioned as measures of

system reliability. Some basic tutorial material for computing loss of load probability is given in Appendix A of the report. Capital costs are described and a process for developing an equivalent annual cash flow is given in Appendix B of the report. The input, output and methodology for production cost simulation models are presented. Appendix C to the report illustrates basic production cost simulation under weekly load duration curves.

The report then delves into synthesis models and considers in detail two types: target mix and mathematical programming. A description of target mix and synthesis is given in Appendix D of the report. The mathematical models are divided into two groups. In one group the investment and production models are directly linked. These models characteristically suffer from a lack of detail in power system modeling. The second group features explicit separation of the investment and production decision making. A plan is synthesized, then analyzed, iteratively, until an optimum plan is achieved. Models in this group offer considerably more precision in modeling system reliability and plant operation, but they are computationally less efficient. A description of a model based on mixed integer linear programming is provided in Appendix E of the report.

The Systems Control, Inc. report on generation emphasizes models and methodologies that represent the state of the art in generation planning rather than the planning processes themselves. Five criteria are established and then used to select models for evaluation.

The criteria are:

- 1) The model should be either proven in its practical application to actual power system planning or capable of solving real-life problems.
- 2) The models should include features that represent the state of the art.
- 3) The model should solve at least the investment and production costing problem of generation planning by an integrated computer package.
- 4) There should be published literature and documentation available spectrum of the different methodologies and capabilities of the state of the art.

The application of the criteria resulted in the selection of six models, which are:

- 1) WASP--A dynamic programming model with probabilistic production costing developed by Jenkins and Joy.
- 2) OPTGEN--A dynamic programming model with deterministic production costing developed by Lee.
- 3) University of Massachusetts Model--A mixed integer linear programming model developed by Noonan and Giglio.

- 4) MIT Model--An Economic-Environmental System Planning Package developed by the MIT Energy Laboratory.
- 5) PUPS--A screening curve model developed by Lee and Dechamps which is capable of treating unconventional generation.
- 6) MNI-GRETA--An optimal control model (MNI) and a Monte Carlo simulation model (GRETA) used by EDF.

The six appendices to the report provide synopses of the available literature on the models.

The models selected are evaluated and compared according to the criteria stated above. The results of the comparison are presented in a full-page table, wherein 21 different features are listed, each followed by a brief description of how that feature is handled in each model. The table is followed by a narration which elaborates considerably upon the contents of the table. No attempt is made to assign overall ratings to the models.

In addition to the six appendices, 28 references are provided in the report.

SECTION 4.1

REGIONAL GENERATION PLANNING; A STATE-OF-THE-ART ASSESSMENT

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ABSTRACT

Regional generation planning is accomplished using a variety of models and techniques. This paper attempts to identify the weaknesses and strengths of these models and techniques in the context of current and anticipated procedures and objectives. The planning process is described, the models and techniques are compared, and recommendations are made where research would be beneficial.

INTRODUCTION

Regional generation planning, and hence the models and techniques associated with the planning effort, must consider the factors which influence the relative success by which utility objectives are met. New methodologies and supporting models which are to find application in regional generation planning must grow out of an understanding of the planning process and of the capability of existing models to relate basic data to utility objectives.

These planning objectives are:

1. To supply all prospective customers' demand with acceptable reliability.
2. To minimize revenue requirements and thus the price of electrical energy.
3. To conform with environmental standards.
4. To maintain the capability to attract sufficient capital to finance new projects.

The process by which regional generation planning attempts to coordinate these reliability, cost, environmental and corporate finance objectives is described. The models and methodologies are discussed and compared, and their adequacy assessed. In addition the mathematical basis for each model and methodology is given. Recommendations for research intended to improve generation planning are given. These briefly include:

1. Development of methods which are computationally feasible for large systems, accompanied by a parallel effort, if necessary, to meet the requirements for new data.
2. Development of practical methods for dealing effectively with future uncertainty.
3. Better integration of the knowledge and intuition of the experienced planner into automated planning methods.
4. Better integration of corporate finance constraints into the synthesis of generation plans.

In the following discussion these statements will be amplified and an effort made to convey their importance with respect to the overall planning problem and the approach to its solution.

THE PLANNING PROCESS

Generation planning begins with estimates of peak demands and associated electrical energy consumption. After identifying the need for generating capacity additions, the planner develops a number of alternative expansion plans, each of which is to be evaluated in terms of capital and operating costs, reliability and siting considerations, and its financial effect on the company and its customers.

Generation varies in size, type and location. Generator unit sizes vary from less than 20 mw for peaking units powered by combustion turbines to 1200 mw for base-load units fueled by nuclear or fossil fuel. Generation unit types vary by the energy source, which may be gas, coal, oil, nuclear, hydro, solar, wind or geothermal, and by the application, which may be for peaking, cycling, or continuous operation. The preliminary selection of the generation site is based on potential for licensing, water and land availability, accessibility to rail or highway transportation, and proximity to the bulk transmission network.

Generation of all types is considered in the development of capacity expansion plans. New technology is considered when capital and operating costs, and performance can be predicted. When feasible sites are available, limited energy generation such as conventional and pumped-storage hydro are included, but receive special treatment as described in Appendix A.

The choice of generation type attempts to minimize the revenue requirement associated with capital and anticipated production costs. Low production costs of base-loaded generation can justify higher capital cost. Similarly the higher production costs of peaking generation may be off-set by lower capital costs. Cycling generation is generally characterized by intermediate production and capital costs. The problem of selecting the mix of generation types to supply a particular load profile while minimizing the sum of capital and production costs is called the "optimal mix" problem. A description of one means of its solution is found in Appendix B.

The decision to commit capital for new generation and transmission must be made sufficiently in advance so that the construction will be complete when the capacity is needed. The new generation must be chosen so as to align with the longer range, broader view of the future system.

The planning process can be divided into long-range and short-range studies. Long-range studies usually look ahead 20 or more years. The goal of these studies is to develop a future system which serves as an approximate horizon for the earlier installation and timing of new generating capacity. They are used to develop concepts for future generation goals such as whether to build concentrated energy parks or dispersed generation. They are useful in providing guidelines for choosing generating sites and transmission corridors. Because of the uncertainties in much of the data associated with long-range planning,

the results of such studies provide approximate guidelines for short-range plans. Since the number of alternate courses of action for long range system development is large, computational requirements may be significant. Because of these uncertainties, and order to reduce these requirements, the use of approximate models for the evaluation of long range plans is generally followed.

Whereas long-range studies provide general guidelines for generation expansion, short-range studies are devoted to the detailed exploration of specific additions. Short-range studies form the basis for the choice of the best alternative plan. Since the construction lead-times of possible generation additions vary from 3 to 12 years, short-range studies include a comprehensive analysis of reliability, environmental, economic, and corporate financial concerns and thus require detailed models supported by the best available data.

Currently, most utilities approach the planning problem by evaluating the features and limitations of an initial set of possible plans, chosen on the basis of knowledge of and experience with the existing system. The alternate plans are compared by analyzing and comparing their respective economic, reliability, corporate, and environmental characteristics. This comparison, coupled with "what if" explorations, provides the basis for funding the most economic plan while meeting corporate constraints.

The evaluation of each of the economic, reliability, corporate, and environmental aspects requires a modeling effort and is generally automated to some extent by one or more computer program(s). The exploration of the trade-offs among the different alternatives is usually done manually, but there is a general agreement that an environment which facilitates man-computer interaction would improve efficiency and encourage greater exploration of alternatives. Finally, there has been a significant effort to automate the entire planning process by formulating it as a problem of constrained optimization. Both the interactive and completely automated planning methods are discussed later in the section "Automated Planning."

Along with each generation alternative considered for inclusion in the ultimate plan, sufficient transmission reinforcement must be included to ensure secure steady-state and transient performance. The cost of such transmission is included as part of the cost of the associated generation alternative.

RELIABILITY

One principle objective in generation planning is to provide sufficient generation capacity to supply the system load, with reasonable reliability, despite unscheduled generation outages and loads which may exceed best estimates. This is accomplished by installing reserve generation. The level of required reserve may be determined by either deterministic or probabilistic methods. In either case, an effort is made to develop indices which are sensitive to the parameters of load and generation whose variations affect the adequacy of the supply. As more of the load and generation parameters that affect reliability enter into the calculation of the index, the computational and associated data requirements of the method increase. In order of increasing sophistication the indices to be described are:

1. Capacity reserve percentage
2. Contingency outage reserve
3. Loss-of-load probability (LOLP)
4. Frequency and duration of capacity deficiency (FAD)

The first two indices are early attempts to relate reserve requirements to reliability of service [1]. The second index is somewhat sensitive to the size of generation units existing in the system. Both indices are easily calculated and require little data. Neither index, however, reflects the effect on system reliability of variations in load factor, in degree of load forecast uncertainty, in composition of generator unit sizes, in planned and forced outage rates, in expected outage duration, and in the level of interconnection with neighboring utilities in combination with the availability of reserve capacity from these utilities.

The third and fourth methods incorporate probability theory and better reflect the influence of the parameters which affect adequacy of generation capacity.

The Loss-of-load probability method (LOLP) [2,3,4] finds widest use throughout the power industry. It provides a one-dimensional reliability index and thereby permits easy and consistent comparison of alternative capacity expansion plans. The method incorporates generation size and outage rates, load uncertainty, variability of weekly peaks, unit maintenance, and benefits accruing from interconnections between cooperating companies. For a description of the method, see Appendix C.

The LOLP is expressed in days-per-year that installed generation capacity is expected to be insufficient to meet the daily system peak demand. This index is calculated by a convolution of a probabilistic model of available generation capacity with a probabilistic model of likely demand levels. The capacity model is represented by a table of capacity levels with the associated probability of having exactly that capacity available. The load model is represented by a load duration curve which relates the loading levels to the percentage of time that each load would be equalled or exceeded. An LOLP of 0.1 days per year is most widely accepted value of the index indicating the required level of capacity reserve.

A state-of-the-art application of the LOLP method for two interconnected areas is currently in use by the member companies of the Pennsylvania-New Jersey-Maryland Power Pool. This program (GEBGE) calculates the probabilities of loss-of-load on a weekly basis which are then added to give LOLP on an annual basis for given load and capacity models. The load model considers business cycle, variations from forecasted load, and statistical knowledge of weather to produce week-by-week probability distributions of daily peak demands. The capacity model incorporates knowledge of seasonal variations in unit capacities, variations in forecasted capacity level, forced-outage rates, and scheduled maintenance.

Since the LOLP index is currently based on a load model reflecting daily peak demands, it is not sensitive to variations in daily load factor. The impact of load management on reserve requirements, however, may be assessed using the LOLP approach by employing an hourly load model, rather than adopting the frequency and duration (FAD) method.

The frequency and duration method [5,6,7] adds a second index to the description of the adequacy of generation reserves to supply anticipated demands. The FAD method decomposes the LOLP index into two components, frequency and duration, whose product is equivalent to the LOLP. Modeling demand and capacity as Markov processes, the FAD allows the effects of repair and maintenance times, and of daily load profile to be incorporated into the assessment of required reserve. It also expresses the characteristics of capacity deficiencies in the same terms as those being used for the reliability assessment of transmission and distribution systems, thus lending itself as a complementary method in the analysis of reliability of supply to the customer as affected by the composite system. For a description of the method, see Appendix D.

The FAD method requires additional processing of existing data on a national basis in order to develop unit outage and repair rates. However, the increase in computational requirements over those of the LOLP method, for large systems, may not justify the additional information developed. The use of FAD as a measure of reliability of service may be required when and if generation and transmission performance are related directly to customers needs. Currently the FAD measure serves only as an index in the comparison of alternate generation plans.

Recommendations for research effort in the determination of capacity reserve requirements include:

1. Demonstrate the feasibility of applying the frequency and duration method to large, interconnected systems, and show need and the potential benefit of this method.
2. Develop relationships between the reliability criteria for generation and those for transmission and distribution systems. Use these to assist in exploring the nature of their combined effect on consumer reliability, and to provide a basis for their more effective coordination.

ECONOMIC ASPECTS

While the regulated utility is obliged to expand its facilities to accommodate new customers, it must do so in a manner which minimizes customers rates while protecting investors' interests. In order to accomplish this, most utilities opt for the minimum revenue requirement criterion when making economic analyses. That is, they examine all possible alternate means of accomplishing any given objective and then select the alternative that requires the least revenue from their customers over the life of the project. The three principle components which enter into the determination of revenue requirements for a given alternative are:

1. Capital costs
2. Production costs
3. Operating and maintenance costs

Capital Costs

Capital costs are a significant part of the total costs. Current estimates for generating capacity range from \$400/kw (1988) for peaking capacity to \$1350/kw (1988) for nuclear capacity. Factors which affect capital costs include type of generation, unit size, site, length of construction period, labor costs, and environmental requirements.

In order to convert a capital investment into equivalent annual revenue requirements, a carrying charge rate is used. The carrying charge reflects the levelized annual amount of revenue required to pay for the facility over its lifespan. The carrying charge is designed to meet the annual costs associated with capital investment. The three main components are: depreciation, income taxes, and annual return (interest on debt, dividends on preferred stock and earnings on common equity). The components of annual return comprise essentially the cost of money.

Production Costs

The production costs associated with a given generation plan are the combined costs of fuel, operation and maintenance incurred in the day-to-day supply of the system demand over some future period. There are three basic methods used for estimating future production costs. They are

1. Deterministic load duration method,
2. Simulation method,
3. Probabilistic load duration method.

In the deterministic load duration method [8,9] the system load is described by a load duration curve while generation is described by a unit list with associated capacities, forced outage rates (f.o.r.) and an order of loading. The capacity of each generator is derated by multiplying its nominal capacity by the probability that that generator is not forced out (1.0-f.o.r.). The units are then stacked into the load duration curve according to the specified order of loading--See Appendix E. The units stacked in first will have the highest utilization. The operating cost for each unit will be based on the energy that it generates over the period for which the load duration curve is a valid representation of system load. The energy generated by each unit is represented by the area that the unit occupies under the load duration curve. In using the load duration curve to represent system demand, the unit commitment problem is avoided yielding computational efficiency, but at the expense of neglecting costs and operational realities associated with unit commitment as well as the savings associated with economic interchange. It is generally recognized that the treatment of forced outages is inadequate. Consequently, the deterministic load duration method finds widest application where computational efficiency justifies some error. Specifically this method finds principal application in optimization programs for long-range screening applications.

In order to better represent the effects of forced outages on operating costs, as well as to improve the estimation of impacts associated with unit commitment, the simulation method [10,11,12] for estimating production costs may be used. This method derives cost estimates by simulating the dispatch of system generation to supply hourly loads specified by a chronological load model. Generation is dispatched on a merit-order or incremental cost basis to minimize production costs. Unit maintenance is scheduled prior to dispatching according to a set of decision rules. The effects of forced outages are included through a gaming approach. The method has the capability to address many of the considerations encountered in actual system operation. These include

- Generator performance factors
- Generator forced outages
- Seasonal variations in generator capacity
- Must-run operation
- Unit commitment costs
- Accurate unit commitment procedures

- . Time-of-day and interchange costs and savings
- . Generator maintenance requirements
- . Hydro and pumped-hydro capacity
- . Pollution constraints
- . Transmission limitations
- . Transmission losses
- . Two area capability with transmission limitations

The principal disadvantages of the simulation approach are the computational and data requirements. Since unit outages are based on a gaming process, the best results are obtained by averaging a number of dispatch scenarios, one varying from another only by the seed value associated with the generation of random numbers. Chronological load data for long-range studies is difficult to specify with confidence. The computational requirements of the simulation approach have led to the development of an analytical technique to calculate the expected value of energy generated by each unit which includes the effects of forced outages, to be discussed next.

The probabilistic load duration method [13,14,15] grew out of the need to represent generator forced-outage-rates more accurately than simply through the derating of units, without incurring the computational burden of dispatch simulation. In the probabilistic method, it is recognized that the energy generated by a particular unit, represented by the area it occupies beneath the load duration curve, depends on the availability of the more efficient units which generally take priority in loading. If a large base-load unit is unavailable, a less efficient unit is likely to generate more energy than otherwise. The object of the probabilistic method is to determine the expected value of energy generated by each unit taking into account the availability of higher priority units. This availability is reflected through vertical shifts in the load duration curve weighted by associated probabilities. See Appendix F.

The probabilistic load duration method, in addition to providing the expected energy generated by each unit over the period covered by the load duration curve (used to estimate production costs), provides the probability of loss-of-load during the period as well as the expected amount of unserved energy. The expected energy generated by each unit considers the possible variations in production cost occurring due to combinations of unscheduled outages and load deviations. The variability of hydro-electric energy may also be included. Efficient methods for including the effects of unit commitment as well as economic interchange must still be developed.

Economic interchange between pooling utilities or regions is a part of daily operation. The effects of this interchange must therefore be considered in evaluating production costs. The generation dispatch simulation approach can calculate multi-area production cost [16] but at considerable computational expense. Research effort aimed at incorporating economic interchange with transmission limitations into a probabilistic method is recommended.

Fixed Operating & Maintenance Costs

These costs include all fixed non-production costs such as labor, supplies and materials, nuclear insurance, etc. plus all variable costs associated with preparing the unit for daily operations. Data regarding these costs must be estimated on an annual basis in order to be integrated into the economic analysis.

Economic Analysis Including Uncertainty

The economic analysis of the various alternatives is based on determining which alternative results in the minimum revenue requirement. The components of the revenue requirements include:

- a. Annual carrying charges on generation capital costs.
- b. Annual carrying charges on transmission capital cost associated with the generation.
- c. Annual production costs.
- d. Annual operating and maintenance costs.

The present worth of these components is computed to determine the plan with the minimum revenue requirements.

Since an electric utility must adopt plans for new generation capacity 3 to 12 years in advance of anticipated need, heavy reliance on uncertain projections of future conditions is necessary. Variations in the availability and cost of fuel, environmental regulations, capital costs, the magnitude and shape of demand, construction lead-times, as well as changing corporate financial conditions and the availability of new technology can have a significant effect on the nature of the economic choice. It is desirable either to choose the plan which is most likely to remain the most economic under possible changing conditions or to provide sufficient flexibility to adjust the plan, without excessive penalty, in response to either favorable or adverse developments.

The sensitivity of the most economic plan to variations in future conditions is assessed by exploring the conditions under which alternate plans are economically equivalent. Utilities most often concentrate on the interplay of break-even values among alternatives for capital cost, fuel cost, and carrying charge rate.

Recommended Areas for future research are:

1. More automation of the process of exploring the sensitivity of the most economic plan to variations in future parameters and conditions.
2. Developing means for incorporating flexibility into a plan and in the specification of the degree of flexibility desired. That is, a balance must be drawn between the costs and benefits of flexibility necessary to adapt to changing future conditions.

ENVIRONMENTAL IMPACT ASSESSMENT

Environmental impact planning is not a process whereby optimization is sought. Rather it involves determining whether potential generating sites can comply with constraints in the various areas where the environment will be affected.

Having reduced the number of potential generating sites by a screening process, more detailed environmental analysis is required to make a final choice. The cooling system development must consider water availability, thermal effects, chemical effects, and reduction of stream flows. The environmental impact assessment [17,18,19] considers factors such as endangered species, effects on other species, existing and potential recreation and commercial aspects. Other concerns are accessibility to existing transmission system and transmission line routing, accessibility to rail and highway facilities, population densities,

flood hydrology, as well as geological and meteorological considerations.

Modeling effort in this area consists mainly of estimating parameters for purposes of comparison with established or forecasted criteria of various regulatory agencies. An overall technique in assessing alternate sites is to list and assign weightings to the considerations which are not essential to the acceptance of the site and to estimate an order of preference based on some scale (1 to 5). The weighting value is then multiplied by the scale value to form an overall score. Alternative sites are then compared for overall score. (See Appendix G)

For measuring thermal effects, current computer programs compute the isotherms on the water body into which the proposed plant is discharging cooling water. Variables are geometry of discharge equipment, angle of discharge, rate of discharge and the body of water accepting the discharge. These thermal effects are then compared with established standards to determine compliance.

Cooling system design is also assisted by computer programs. These programs are designed to minimize costs based on varying such parameters as size of condenser, cooling tower size, tube length and number of tubes in the discharge mechanism.

Computer programs are used to estimate the radiological dose to man resulting from radioactive releases from a nuclear power plant. The dispersion of releases to the atmosphere is calculated using site meteorological data to arrive at concentration in the air at important receptor locations off-site. The model then calculates the dose to man via the exposure pathways (i.e. inhalation, ingestion, direct exposure) that exist at each receptor location. In a similar manner, doses resulting from the exposure to radio-nuclides discharged to the aquatic environment are evaluated by considering the important exposure pathways at affected receptor locations. These estimated doses to man are compared to design objective values established by the appropriate regional agency to assure the impacts of plant releases are as low as reasonably achievable.

Pollution emissions standards vary widely. They are set by either local or regional agencies. These standards set some minimum permissible percentage of sulfur dioxide (SO_x), nitrous oxide (NO_x) and particulates which can be discharged into the atmosphere by a proposed generating station. These emissions may be calculated manually from the specific plant characteristics or they may be obtained from a dispatch simulation similar to a production cost program. This feature enables the identification of emissions associated with all generators on the system based on the estimated generator operation. Results obtained by either of these methods are used to demonstrate compliance with local and regional air quality standards.

Research effort in environmental planning is recommended in field measurement verification of results obtained from analytical calculations.

CORPORATE FINANCE

While most of the methodologies discussed in this report are regional in nature, the corporate financial aspects of generation planning are usually limited to the financial analysis of a single specific utility. Although generating capacity may be planned on a regional basis with the costs and benefits shared by the participating utilities, the corporate effect of this

involvement must be analyzed by each utility singly to assess its capital funding requirements, its cash flow situation and its tariff requirements.

The electric utility industry is one of the most capital-intensive industries in the United States. An average of three dollars of plant investment are needed to generate one dollar of annual sales. Over the past decade the electric utility industry has experienced a substantial increase in the amount of capital allocated to new generation capacity. This trend is expected to be maintained over the next decade. Contributing to this increase are: rapid inflation of construction costs, costly environmental protection requirements, and a general commitment to nuclear power which is particularly capital intensive.

Capital funds to support the construction of new generation capacity are obtained from both internal and external sources. Internal sources (depreciation, retained earnings, and deferred credits) meet about 40 percent of the capital needs of the utility. The remaining 60 percent must be obtained in the nation's competitive capital market. The need for large amounts of capital to finance generation capacity stresses the financial viability of the electric utility. Consequently generation expansion planning must be closely coordinated with corporate financial planning.

Important in financial planning is the need to maintain desired ratios of long-term debt, preferred stock equity and common stock equity. These proportions are established to minimize the overall cost of capital, while ensuring that the portion of stock equity is sufficiently large to absorb earnings fluctuations and thus guarantee continuing ability to pay interest on debt. Of equal importance in financial planning is the task of maintaining a credit rating necessary for continued access to the nation's credit markets.

A corporate finance model (see Appendix H extracted from Ref. 20) examines the financial consequences of the external investment requirements associated with different capacity expansion plans. Of particular interest is a projection of the tariff levels necessary to achieve the desired rate-of-return on common equity. Tariff requirements must be of such a level that increases have a reasonable likelihood of being granted without excessive lag by the presiding regulatory commission. Any alternative plan which meets the minimum revenue requirements must therefore be tempered to reflect constraints on available capital.

Existing financial models, adapted to the digital computer, either analyze the financial aspects of a particular investment plan, or, less often, choose the optimal value of one or two important variables (e.g. maximize return on equity, minimize amount of external funds required, maximize interest coverage ratio.) The optimization approach [21] currently suffers from oversimplification of accounting procedures, inflexibility in ability to choose objectives, and a limited number of control variables which are specified in the course of the optimization.

Some of the analysis models [22,23,24] merely simulate the accounting systems. Others [20] contain significant numbers of behavioral equations which translate general input information into specific forecasts of corporate financial information. For example, a model could contain an equation which estimates distribution expense as a function of the number of customers and the inflation rate (or wage rate).

These models are most often employed in long-range financial planning and so they typically have planning horizons which extend 20 years or more into the future. Often they are annual models, although some have been constructed to provide monthly output for the first year or two of the forecast period. Cash management problems can be analyzed by those models with monthly capabilities.

A great range of variation exists in the amount of detail provided by the financial model. Generally, the more detailed the output, the more extensive the input, and the more complex the operation of the model will be. In nearly all cases, however, the models can generate all of the major items of financial information found in the typical annual report, i.e. the balance sheet, the income statement, the source and disposition of funds statement, and some summary operating statistics.

Many utility companies have such models today. Some were developed internally while others were adapted from package models marketed by a number of computer software companies as well as by companies which are traditional financial consultants to the utility industry. In an increasing number of cases, these financial models are being combined with other models into integrated forecasting systems. Often such an integrated system will involve: (1) national and regional economic models, (2) sales and load forecasting models for the utility's service territory, (3) a fuel price forecasting model, (4) a production cost model which simulates the electric production operations of the company (5) a future generation planning model, and (6) a financial planning model.

Once the generation expansion is specified, the investment requirements are determined. From this information, the corporate finance model then estimates the tariff requirements and other implications of adopting the specified plan. (e.g. earnings, interest payments, external funds required, price trends of common stock.)

Whether such tariff requirements can be met is a decision left to management. If they cannot, the generation plan is altered, the investment requirements reassessed, and new tariff requirements determined. This procedure is repeated until revenue requirements are minimized while yielding tariff rates which are likely to be granted.

Suggested research efforts in this area include:

1. Regional and national studies to assess the additional long-term costs to consumers arising from short-term compromises in the choice of generation plans. These additional costs, resulting from greater revenue requirements and necessitated by corporate finance constraints, would provide regulatory commissions with information on the extended effects of their decisions.
2. Closer integration of corporate finance constraints into the development of optimal generation plans.

AUTOMATED PLANNING

Considerable effort has been devoted to the automation of the generation planning process. There are two principal objectives: (1) to provide an efficient means for screening the possible alternatives available for long-range system development, and (2) to assist in the short-range optimization of the choice and timing of generation additions from among specified candidates.

Techniques that attempt to achieve the first objective [8,9,25,26] formulate the planning process as a problem of constrained optimization. Generation capacity additions are chosen to minimize the present worth of capital and operating costs over the planning period while supplying projected load with sufficient reserve. These techniques use approximate models such as the deterministic load duration method to evaluate production costs, and percentage of peak demand to specify reserve requirements. Although they tend to oversimplify the problem to conform with the more efficient solution methods (linear programming), they are suited to long-range screening applications where the accuracy of supporting data is generally poor. Reference [27] provides an excellent description and comparison of these techniques.

Techniques that are intended to assist in the optimization of short-range plans [1428] use more accurate models, and are more comprehensive in scope. In addition to reliability constraints, the minimization of capital and operating costs is subjected to corporate and environmental constraints. The techniques described in the two references cited use simulation or the probabilistic load duration method to estimate production costs, and base reserve requirements on an LOLP criterion. Generation additions are selected and scheduled from among specified candidate additions to minimize the present-worth of capital, fuel, operation and maintenance costs incurred over the study period. Optimization is accomplished using either decision rules intended to simulate the selection process or dynamic programming.

The automation of short-range planning has met with limited acceptance because the techniques (1) tend to neglect constraints and objectives which are of a non-quantifiable (political, social,...) nature, (2) fail to recognize many of the particular characteristics of the existing system, and (3) bypass the judgement and intuition of the planning engineer who has familiarity and experience with the particular system.

Partial automation of the planning process tailored to facilitate engineer-computer interaction appears to overcome the three limitations cited above. The interactive on-line planning approach would automate all standard cost, reliability, corporate financial, and environmental analysis procedures, and would support them with a common data base and data management system. The objective is to improve the efficiency with which alternate plans may be analyzed by relieving the engineer of the tedious, time consuming task of data handling. Screening procedures would assist the engineer in synthesizing alternate plans, and performance indicators would assist in assessing trade-offs.

The engineer would investigate feasible solutions with desirable characteristics, would be encouraged to explore trade-offs among the areas of concern (costs, reliability, environmental impact and corporate finance), ask "what if" questions about the system and data, try different planning strategies, and in the process may gain intuitive insight into system relationships otherwise unavailable. It is felt that the give-and-take aspects of regional planning may best be reflected by the informed engineer in the partially automated environment offered by the interactive planning process.

CONCLUSIONS AND RECOMMENDATIONS

This paper describes the concerns of the electric utility in the generation planning process. The methodologies and models used to address these concerns are described and their features and limitations discussed. Areas of potentially fruitful research are identified.

Improvements in the methodologies and models used in generation planning must be based on utility needs and concerns. Much effort has been devoted to the development of tools which have little immediate practical application resulting in a gap between published methodologies and the level of implementation. This gap could be narrowed if, with the introduction of a new methodology, parallel efforts were made to demonstrate computational feasibility for large systems and to indicate a procedure for acquiring any necessary new data.

A summary of the recommendations for future research include:

- More automation of the process of exploring the sensitivity of economic analyses to variations in future parameters and conditions.
- Determination of the benefits and feasibility of applying the frequency and duration method to large interconnected systems.
- Develop a basis for the more effective coordination of reliability criteria for generation with those of the transmission and distribution systems.
- Field measurements to verify models used in assessing environmental effects.
- Regional and national studies to assess additional long-term costs arising from short-term compromises due to corporate finance considerations.
- Development of methods which can more clearly integrate tariff requirements and the corporate finance implications into the choice of the economic expansion plan.
- Probabilistic production cost method which incorporates economic interchange with transmission limitations and reflects unit commitment effects.
- Emphasis on an "interactive" approach in automated planning with appropriate data base and data management.

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REGIONAL POWER GENERATION PLANNING METHODOLOGY: A SURVEY

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In this report, the University of Michigan as subcontractor to the University of Oklahoma provides a survey of power generation planning methodology. The generation planning function is described and the use of both synthesis and simulation models within generation planning is examined. Those factors which are important for distinguishing state of the art models are identified and recommendations for development work in generation planning methodology are made.

1. GENERATION PLANNING FUNCTION

Power system planning is an integrated process where strong interface exists between the component functions of generation planning, transmission planning and environmental, financial, operations, fuels supply and R&D planning. Generation planning serves to identify the technology, size and timing of the next few generating plants to be added to the power system. This function is carried out with the primary objectives of insuring that (i) sufficient generation capacity is available to satisfy future demand for electricity and (ii) the future cost of power generation supply is economically efficient. The first of these refers to system reliability which enters the planning process as a design constraint to be satisfied in each year over the planning horizon. Economic power supply is achieved by identifying expansion plans which minimize the present sum equivalent of the capital and operating costs for power generation over the planning horizon. Overview descriptions of generation planning can be found in ([1], [10], [17], [27]).

This paper surveys regional power generation planning methodology. The term "generation planning methodology" refers to any model, tool or procedure used in performing the generation planning function. The term "regional" simply implies that planning methodology appropriate to large scale power systems is a point of focus. This particular survey does not provide a historical chronology on the developments in generation planning methods over the past 20-30 years; nor does it attempt to be encyclopedic with respect to all of the detail variations currently available with generation tools. Rather the survey's purpose is to clearly identify the basic state of art in generation planning tools and, also, to provide a framework for understanding how these tools are employed in the planning process.

In Section 1, the generation planning function is defined with emphasis given as to how this function interfaces with other power system planning functions. In Section 2, generation planning methodology is presented as a two phased process - a synthesis phase followed by a simulation or analysis phase - and basic planning models are then introduced by describing how each is utilized within this process. Simulation models for system reliability, capital costs and production costing are discussed in Section 3 while basic types of synthesis models are addressed in Section 4. Descriptions of examples for each of these model types are given in appendices. Finally, Section 5 provides discussion on necessary extensions to current generation planning methodology.

Typically, generation planning has a non-spatial framework in that plant location decisions and the necessary investments in transmission and distribution equipment are not explicit to this planning function. Several factors cause generation planning to be a large scale decision making problem. Plans for power plant additions in the near term are developed under large planning horizons (15-30 years). Since any new plant will impact the power system over the plant's lifetime then mid and long range plans must also be established to provide a context for evaluating the impact of near term power generation decisions. Another reason for the problem being large scale is due to the wide variations that occur in the supply and demand patterns for power generation within each year. To some extent these variations must be modeled if an economically efficient balance between the production and capital costs for power generation is to be secured. Finally, generation planning is complicated with uncertainty in many of the key system parameters. Accordingly, proper planning requires consideration for a number of different future power supply conditions.

The primary decisions made in generation planning are the mix of plant type and the size and timing of individual units to be installed. Secondary decisions concern the operation of installed capacity to meet a demand for electricity which varies by hour, day and season. System operation must be considered to insure that an expansion plan is operationally feasible and to estimate the production costs associated with such a plan.

Although final determinations of plant mix are not made independently of plant size and timing, it is useful to consider them separately for understanding the basic economic forces involved in generation planning. The plant mix decision is made by finding an economic balance between investment and operating costs. To understand this balance, consider a load-duration function which expresses demand for an operating period in terms of a set of components, each of which is distinct in terms of its duration during that period. For example, there may always be at least 1000 megawatts of demand during a weekly period, and so a 1000 megawatt component of demand will have a full duration. Similarly, the demand may be 1500 megawatts or greater for 50% of the time during a week; hence there is a 500 megawatt component with a 50% duration. The plant mix decision involves assigning to each of several demand components that generation type which can satisfy the demand at the minimum total cost. Efficient plants which tend to require large investments are assigned to meet demand with high duration while plants with low capital but high operating cost are better suited for short duration demands.

Plant size and timing decisions are concerned with the common problem of finding an optimum balance between economies of scale and the opportunity costs of temporary excess or under capacity. The stochastic nature of power plant availability also effects optimal plant size because the presence of larger plants will require that more excess capacity be held in reserve in anticipation of a breakdown. Hence, the random nature of plant availability introduces a diseconomy of scale with respect to plant size.

System reliability and power generation cost are not the only relevant issues in generation planning. Figure 1 broadly depicts the interface that exists between generation planning and other functions. Within this interface information flows in both directions. The generation expansion plan is an important input to transmission planning where the plan is given a spatial definition ([21]). Transmission planning can feedback restrictions which are tied to the technical or economic feasibility of implementing the generation expansion plan within the power supply network.

Environmental planning has responsibility to identify plant design requirements and fuel types which will be in compliance with air and water quality restrictions ([23]). This information flows into generation planning to directly restrict the available options in formulating sys-

tem expansion plans. Environmental planning has a primary role in plant location decisions. Consequently, generation expansion plans are an essential input to this function. As acceptable plant sites become scarce, environmental planning can flow restrictions back to generation planning which limit the number of certain plant types that can be added to the power system.

Figure 1

Generation/System
Planning Interface

Financial planning receives cash flow information on system expansion from generation planning and has responsibility for determining the electric utilities capability for financing the the planned expansion ([13]). Financial planning can indirectly restrict the generation planning process by placing constraints on the construction budget that a utility can support.

Both fuels supply and operations planning provide generation planning with information necessary for proper modeling of power system operation. Fuels supply inputs estimates on price and availability of different fuel types, nuclear fuel cycles and costs, and information relating to long term fuel contracts. Operations planning supplies information on the existing set of power plants (e.g., heat rates, maintenance, plant usage or capacity factor constraints, energy sales and purchases). R&D planning is, also, basically an information source to generation planning supply-

ing information on the cost and operating characteristics of future generation technologies.

2. GENERATION PLANNING METHODOLOGY

Regardless of the tools or specific models applied within different organizations, generation planning methodology entails a two phase process, synthesis followed by analysis (see [1], [27]). In Phase 1, a synthesis method is employed to construct guideline expansion plans. A variety of synthesis methodologies are available to system planners: expert judgement, target plant mix models and computer based mathematical programming models. All of these have the common purpose of reducing the virtually infinite number of possible system expansion configurations to a small subset of economically efficient guideline plans. The guideline plans serve as an input to Phase 2 where analysis or simulation models are applied for more accurate representation of system reliability, individual plant operation and capital/production cost cashflows. In addition, during Phase 2 a sequence of marginal adjustments or fine tuning is applied to the set of expansion guidelines for the purpose of achieving higher levels of economic efficiency.

The structure of a guideline expansion plan is an ordered sequence of plant additions by type and size over time. Adjustments to the plan in Phase 2 will ideally involve only small perturbations to the sequencing of the plant additions. The specific basis for making these adjustments may be to bring the plan in line with system reliability requirements or to improve the overall economics of power generation supply. If radical changes to the guideline plans are required then the synthesis tools being employed are inadequate and the rationale behind the two phase planning methodology is not being served. Simulation models provide more accuracy than the system modeling present in the synthesis phase; however, simulation is computationally laborious. Accordingly, under the two phase process the system planner is seeking to avoid a global trial and error search via simulation models. Simulation models and synthesis models are complementary - not supplementary - to each other within generation planning.

The complexity of any generation planning study is determined by the number of generation alternatives under consideration and by the number of constraints that exist for power plant operation. As the complexity of the expansion study increases, then it is normal for the use of formal quantitative synthesis models to increase. When synthesis is based strictly on "expert judgement," the system planner applies his experience and understanding of the power system to directly fabricate a manageable but diverse set of economically efficient expansion plans. Target mix models are used to identify the most economic generation plant mix for the system in some future target year of the planning horizon. Target mix models do not address plant size decisions and,

consequently, must be joined with "expert judgement" (i.e., using the target generation mix as a guideline the system planner can assemble a specific sequence of plant additions over time).

Mathematical programming models are computer based and represent the most advanced level of synthesis methodology. Such models have unfortunately been referred to as optimization models with the implications that they are able to synthesize the single best generation expansion plan for the power system. This is not true for two reasons. First, the solutions are only optimum for the mathematical model and the programming model does not have the accuracy of a pure simulation model. Also, due to uncertainty in many key parameters of the study and due to the informal but quite real restrictions that can impact on generation planning from other planning functions, it is unreasonable to argue for some single best plan. Rather, the goal of synthesis is fabrication of multiple, diverse and economically efficient expansion paths, thereby providing the system planner with the flexibility necessary for dealing with uncertainty and other utility objectives.

3. SIMULATION MODELS

Given a generation expansion plan, simulation models are used to predict for each year of the planning horizon (i) power system reliability (ii) capital and production cost cash flows and (iii) power plant operation. Recognizing that power system operation is changing nearly continuously in time and that planning horizons run 15 to 30 years in duration, then one can accept the impracticality of trying to predict with complete precision all of the events which impact on the system attributes delineated above. If simulation models are to be computationally tractable, a certain amount of approximation to power system operations is necessary. In deciding upon a simulation model, the system planner will make a tradeoff between the desire for prediction accuracy and the need for computational efficiency.

System Reliability: For reliability simulation models the generation expansion plan is a model input. The timing of plant additions may be left unspecified providing only an ordered sequence of additions by type and size; however in this case, the simulation model must be programmed to add plants whenever system reliability drops below the acceptable level. Two measures of system reliability are used in generation planning, loss of load probability (LOLP) and installed reserve capacity. The LOLP measures (in units of days/year) the probability that available generation capacity will be less than demand. Due to randomly occurring plant outage, available capacity is a random variable and due to planned outage for preventive maintenance and other seasonal variations in capacity sources, the probability distribution of available capacity will vary over any operating period. Standard practice in generation planning calls for

setting an upper bound specification on the average LOLP (i.e., average risk) or maximum LOLP (i.e., peak risk) for each operating period.

Installed reserve capacity for each operating period is a more straightforward measure; it is the ratio of installed capacity margin (i.e., installed capacity minus period peak demand) to the period peak demand. Installed reserve capacity is frequently employed as a computationally simple substitute measure for LOLP. For example, when a group of electric utilities formalize planning through a power pool, the LOLP is the reliability criteria used in generation planning. The equivalent requirement on installed reserve capacity may be easily computed, post facto, from the pool's recommended expansion plan. The computed percent reserve is then passed on to the participating utilities as the reliability criteria to be used in pursuing generation planning on an individual company basis.

Methodology for computing LOLP is well established. Several excellent references ([3], [4], [8], [11], [26]) cover this methodology and some basic tutorial material is given in Appendix A of this paper. The differences which exist in LOLP reliability simulators are due to (i) the level of detail that is used in modeling the variation in LOLP over an operating period and (ii) the accuracy with which available capacity is represented in any single LOLP computation. Computing LOLP on a weekly basis rather than monthly will presumably give a more accurate LOLP result for the entire operating period; however, if the modeling of available capacity within each week is poor then the gains in modeling accuracy may be negligible. Those factors which are important to accurate modeling of available capacity are: (1) preventive maintenance modeling during each subperiod (2) modeling excess available capacity from tie-lines to other power systems (3) the impact of energy limited generating plants on available capacity throughout the subperiod and (4) the number of distinct forced outage states for a generating plant.

In modeling the impact of preventive maintenance schedules, the simulator should allow for user specified schedules in the early years of the planning horizon but, also, contain the necessary logic for automatically scheduling plant maintenance in later years. Present simulation logic attempts to schedule maintenance so as to levelize LOLP over each operating period. However, scheduling preventive maintenance for a power system is considerably more complex ([6], [28]) and as actual scheduling methodology becomes more formalized one can expect to see continued extensions to the scheduling rules used in simulation models. For the 2nd and 4th items mentioned above, the difficulties are not with simulation methodology but with the acquisition of accurate data. As regards the third item, for power systems with significant energy limited generation capacity the computation of LOLP is complicated with available capacity incurring significant deterministic variations within weekly subperiods (i.e., as any power plant reaches its energy limit

before the week is over then available capacity is reduced). To accurately model these variations in available capacity, one must link LOLP simulation with production costing simulation ([15]).

Capital Cost: The capital cost for power generation plants include depreciation, taxes, insurance and capital financing costs (including interest during construction) ([13]). Given a generation expansion plan (by type, size and installation date) and the capital cost data cited above, the process of constructing the annual capital cost cash flow is simple (see Appendix B).

One issue regarding capital cost cash flow modeling does warrant some discussion. In simulation, a plant's cash flow for capital cost may be represented as a levelized cash flow or as one which varies over time. With levelized models, a plant's capital cost is assumed to start the year the plant begins operation and the annual cash flow is modeled as uniform over the plant's operating life. Actually, capital cost begins to flow once construction begins and the cash flow is not uniform over time. When a utility's supply of capital tightens then the interface between generation planning and capital financing becomes more significant and use of the more accurate time varying capital cost simulation usually proves necessary.

Production Cost: Simulation models for production costing serve a dual purpose for the system planner. For a specified generation expansion plan, the simulator will estimate the production cost across the planning horizon and also, assess the plan's operational feasibility. An expansion plan is operationally feasible if all demand within each operating period can be satisfied while simultaneously meeting (1) preventive maintenance requirements (2) running time constraints, if present on any thermal units (3) plant output constraints for energy limited power plants (4) renewal constraints on energy storage plants (5) spinning reserve constraints (6) constraints on plant start up and shut down times and (7) established energy sales and purchase agreements. In estimating total production costs, the model should account for direct production fuel cost, fixed and variable operating/maintenance cost and plant start up costs. Additional information from a production simulator includes fuel requirements estimates and power plant capacity factors, the latter being quite useful for identifying economic improvements to the expansion plan.

Basic methodology for production simulators entail dispatching plant production against load. The operating periods are decomposed into weekly subperiods with either a load duration curve or a number of chronologically ordered load duration curves specified for each subperiod. Economic priority lists for unit commitment and plant dispatch are also specified. While insuring that all operating constraints are satisfied units are dispatched against load so as to minimize fuel costs. Appendix C illustrates basic production cost simulation under weekly load duration curves and a number of references ([2], [9], [15], [16],

[22], [26]) are also recommended.

The important differences in production simulation methodology all relate to the tradeoff between modeling accuracy vs. computational efficiency. Three issues stand out:

- weekly dispatch under weekly load duration curves vs. daily dispatch under chronologically ordered load models
- deterministic vs. probabilistic dispatch and
- single vs. multiple block models for power plant production

The major arguments for employing daily rather than weekly dispatch is to achieve greater accuracy in plant start up costs or modeling energy storage system operation where renewal occurs several times a week. For pumped hydro plants, weekly dispatch models have proved satisfactory when appropriate weekly supply constraints have been used. However, for newer energy storage technologies the issue is unresolved as to whether weekly dispatch can provide the accuracy necessary for generation planning.

As regards deterministic vs. probabilistic dispatch, the former assumes a power plant's available capacity is given by the unit's expected available capacity while the latter treats available capacity as random using the same probability model as employed in LOLP computations. Deterministic dispatch is computationally simpler but, in general, results in underestimating the utilization of peaking units and, as a result, underestimates annual production costs. The strongest argument for probabilistic dispatch is the fact that it may be directly combined with reliability simulation to provide a consolidated overall system simulation package.

With the issue of single vs. multiple block models for production dispatch one is concerned with the simulation accuracy for power plant heat rates and ultimately the accuracy in modeling production cost. In general, a power plant's heat rate does not remain constant over the entire range of output levels. Single block models assume a constant heat rate while multiple block models account for the variation. Multiple block models significantly compound production dispatch modeling. Unfortunately, for all three of the issues discussed above no standard guidelines exist in terms of quantifying the errors introduced when using the simpler modeling strategies.

4. SYNTHESIS MODELS

As previously mentioned, synthesis models are used to generate economic expansion guidelines. They are not designed to provide the detailed evaluation information that one finds in simulation models. Two varieties of formal syn-

thesis models are considered: target mix models and mathematical programming models.

Target mix models ([20], [27]) simplify power system modeling by assuming (i) the existing system is optimally configured for the present demand and (ii) the capacity factor for plant additions will remain constant over time. This enables one to address cost minimization through plant cost models which are simple functions of the plant's output over a single operating period. A load duration curve on demand growth for the planning horizon is constructed and then decomposed into horizontal blocks of distinct duration levels. Using the cost functions noted above the generation technologies may be matched to the blocks of demand growth such that total cost is minimized. The matching defines for the entire planning horizon the cumulative amounts of capacity to add for each generation type. The cumulative capacity additions are easily converted to a target generation mix which the system planner will strive for in formulating a complete expansion plan.

Target mix models, as presently developed, assume operational independence among power generating plants. This presents a problem for accurate modeling of energy storage technologies because they are economically coupled to base load generation. However, target mix models are attractively simple. They do not require a computer and over the years have proved quite useful in generation planning. For a mathematical description of target mix synthesis see Appendix D.

Mathematical programming models draw upon the theory of constrained optimization ([12]) for synthesizing generation expansion plans. In general, the models are complex and require large scale computer systems for implementation. As opposed to target mix models they are dynamic with the ability to specify capacity additions in each year over the planning horizon and they do account for variation in plant operations over time. Still, the modeling of production and system reliability is still not as detailed as simulation models. The formal optimization objective of these models is to minimize the present discounted sum of all capital and production costs over the planning horizon while insuring that system reliability and operational feasibility is maintained in each operating period. In synthesizing a mathematical minimum for total generation cost, the optimization logic must necessarily link the investment and production cost. The methodology for forming this linkage provides a useful base for separating available mathematical programming models into two groups. Under one group the investment and production modeling are directly linked and allow for completely rigorous synthesis of mathematically optimal expansion plans. However, a characteristic of models with a unified investment/production framework is loss of detail in power system modeling. Installed capacity reserve or approximations to LOLP are used for measuring system reliability. Also considerable aggregation of power plants and their operation over time is typical. References

([7], [18], [19]) illustrate this first group. Specific optimization techniques common to unified models are linear programming and mixed integer linear programming. Models which are limited to linear programming optimization cannot deal with plant sizing decisions. Finally, unified mathematical programming models do have high computational efficiency and are quite amenable to performing large scale sensitivity analysis.

The second group of models distinguish themselves by explicit separation of the investment and production decision making. In this case, optimization involves a two stage iterative search. In stage one, capital cost and a collapsed production cost model are used in synthesizing an expansion plan. In stage two, a detail production cost model is used to evaluate the plan and to update the collapsed production model used in stage one. Convergence to a least-cost plan occurs when the detailed and simplified production models converge. Relative to the first group these models offer considerably more precision in modeling system reliability and plant operation. As one might expect, computationally they are less efficient and with some models convergence to a mathematical least cost plan is not guaranteed except through complete enumeration. References ([5], [14], [23]) pertain to models which separate investment and production. Formal optimization techniques used in this second group include dynamic programming and mixed integer linear programming. Dynamic programming models are rigorous but can prove unwieldy when the number of generation alternatives become large. For a mathematical description of a model based on mixed integer linear programming see Appendix E.

5. PROBLEM AREAS IN PLANNING METHODOLOGY

The focus of previous advances in generation planning methodology has been greater modeling accuracy in system reliability and production operations. This is true for both the simulation models used in analysis and the mathematical programming models used in synthesis. There have also been limited advances with respect to making planning models more computationally efficient and, simply, easier to use. However, growing complexity in power system operation (e.g., new technologies and system interconnections) have tended to mask the benefits in this area.

In seeking to identify fruitful directions for advancing generation planning methodology, the pragmatic issue of planning process execution looms as most important to this author. Two specific areas warrant discussion:

- (1) Large scale uncertainty in many key parameters is a problem (e.g. future demand, fuel prices and availability and new technologies) and left unchecked it seems to question the real benefit of increased

precision in standard operations modeling.

- (2) The growing scarcity of basic inputs to power supply (e.g. capital, land, and fuel) has intensified the restrictive impact that other functions (see Figure 1) have on generation planning.

Both of these problems draw attention to weaknesses in the existing development of synthesis methodology. Uncertainty should be confronted by synthesizing compromise plans which can provide sound economics and quality of service under a variety of futures. Present synthesis models are not designed to identify alternative expansion paths which represent systematic compromise to the problem of uncertainty.

As regards increased restrictions on generation planning from other planning functions, if these restrictions are of the kind which directly exclude specific generation alternatives then the task of synthesis is actually simplified. However, this is not the case. Restrictions such as limits over time on the use of capital, land and fuel are indirect and their presence makes synthesis more complex. Synthesis models for generation planning which integrate the restrictive impact of other functions have yet to be developed. The techniques of "compromise programming" ([25]) and decision analysis ([24]) may prove to be a fruitful source in extending synthesis methodology for both of the above problem areas.

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COMPARATIVE ANALYSIS OF GENERATION PLANNING MODELS
FOR APPLICATION TO REGIONAL POWER SYSTEM PLANNING

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Systems Control, Inc.
Palo Alto, CaliforniaINTRODUCTION

This paper reports the results of a study made by Systems Control, Inc. as a subcontractor of the University of Oklahoma, under the auspices of the Electric Energy Systems Division of the U.S. Department of Energy, to survey the state of the art in generation planning models and to assess their applicability to regional power system planning.

Study Objectives

The basic objectives of the study can be summarized below:

- Define the problems of generation planning for a regional power system.
- Survey the state-of-the-art models that are available to address these problems. Perform a comparative analysis of representative models.
- Recommend areas of research and development, if any, that are needed to perform regional generation planning.

Study Scope

In this study, emphasis is on models and methodologies that represent the state of the art rather than planning processes. In particular, by the words "models" and "methodologies", we mean mathematical procedures that are computer-based for the most part, with limited human interface. Since this definition still includes a large number of different models, we have further restricted the scope by examining only those models which address the generation investment problem directly in their formulation.

Generation planning, being part of the overall system planning of a power system which includes generation, transmission and distribution facilities, should ideally be solved with consideration of the interface with transmission and distribution planning. An attempt was made to combine generation and transmission planning in a single formulation (21). However, due to the complexity of the problem, it is unlikely to be both computationally feasible and sufficiently accurate. This approach will, therefore, not be considered in this paper. Included in the scope, however, will be the interface between the generation planning models and plant-site-related transmission investment.

Fig. 1. Generation Planning Functions and Interface with Transmission Planning

Figure 1 shows the major functions of generation planning and the interface with transmission planning. The interface with transmission planning occurs in real life at all levels of planning and operation. For systems with strong internal transmission capability, most of the interaction is through power plant siting and the use of interconnection with neighboring systems as a means of reducing generation requirement. The interconnection option will not be included in the scope of this report.

Excluded from the scope also is the problem of near-term energy management which includes scheduling of maintenance and nuclear refueling and scheduling of seasonal hydro resources. Data analysis which provides load forecast, forced outage rates, hydro inflow data, etc. is likewise not considered. Corporate financial models which simulate the financial state of a utility for a given expansion plan are also excluded. Detailed production costing and reliability assessment models are not analyzed with the exception of the GRETA model of Electricité de France (EDF) which forms part of their overall planning package.

The criteria for model selection will be discussed in Section II. Six models were chosen for the comparative analysis. They are listed below:

- WASP - A dynamic programming model with probabilistic production costing developed by Jenkins and Joy.
- OPTGEN - A dynamic programming model with deterministic production costing developed by Lee.
- University of Massachusetts Model - A mixed integer linear programming model developed by Noonan and Giglio.
- MIT Model - An Economic-Environmental System Planning Package developed by the MIT Energy Laboratory.
- PUPS - A screening curve model developed by Lee and Dechamps which is capable of treating unconventional generation.
- MNI-GRETA - An optimal control model (MNI) and a Monte Carlo simulation model (GRETA) used by EDF.

In Section III, the models are evaluated according to the criteria of Section II. The comparison will proceed by criteria, so that the contrasts between features of various models are emphasized. Finally, in Section IV, the areas that require further research and development for the purpose of application to regional power system planning will be identified.

Each of the models are described in an appendix which is a synopsis of the available literature on the model. The appendices are organized under the following headings:

- Scope
- Objective
- Constraints
- Method of Solution
- Production Decisions
- Investment Decisions
- Limitations

- Examples and Test Cases
- Performance Capability

CRITERIA FOR MODEL SELECTION AND EVALUATION

An extensive literature survey on generation planning models was conducted before the final selection of six models was made. Both U.S. and European literature were searched. A bibliography is provided at the end of this paper. Because only a limited number of models can be evaluated and compared in this paper, a set of criteria was used in the selection process. They are listed below.

Criteria for Model Selection

- The model should be either proven in its practical application to actual power system planning or capable of solving real-life problems.
- The model should include features that represent the state of the art.
- The model should solve at least the investment and production costing problem of generation planning by an integrated computer package.
- There should be published literature and documentation available which describe the methodology in sufficient details to allow proper evaluation.
- The final set of models selected should present a reasonable spectrum of the different methodologies and capabilities of the state of the art.

The six models listed previously meet the above criteria. References to other models are found in Section V BIBLIOGRAPHY. Anderson (22) surveys the linear programming methodology which is used in the University of Massachusetts Model and the Westinghouse Model GENOP (see Day and Menge (24)). Another Linear Programming model similar in character to the MIT Model is one developed by Gordian Associates. Two models in addition to PUPS which use screening curves in static optimization procedures are OGP of General Electric (Garver, Stoll, Szczepanski (26)); and the model of the Central Electricity Generating Board of Great Britain (Phillips and Jenkin (28)).

Definition of Regional Generation Planning

The major objective of this study being assessment of the applicability of the models to regional generation planning, it is necessary to define the scope of regional generation planning for the purpose of establishing the criteria for model evaluation.

A region is taken to mean the service area of more than one contiguous electric utility. A strict interpretation of this definition should include a statement that there is more than one decision maker in finalizing the expansion plan, otherwise the

region would be equivalent to a single power company. When multiple decision makers from different utilities are involved, they will have their own objective of minimizing the cost of their own system, unless they have a coordination agreement whereby the objective of minimizing the total cost to the region overrides the individual objectives and a formula is used to share the costs and benefits on an equitable basis.

No generation planning methodology is available to address the regional planning problem with a multi-dimensional objective function, as would be the case involving multiple decision makers with different objectives. Because of lack of methodology, regional planning entities usually resort to one of two approaches:

- (a) A single objective function with subsequent cost and benefit sharing, or
- (b) Coordinated planning by individual utilities with various degrees of information exchange which may result in jointly-owned and jointly-operated generation facilities.

The latter approach is neither well defined nor well enough understood to allow either exact mathematical formulation or the development of planning models. It is therefore not a suitable definition of regional planning for the purpose of model evaluation. On the other hand, all generation planning models considered in this paper contain a single objective function and can be used in the former approach, even though they do not address the problem of cost and benefit sharing. Therefore, the following problem formulation for regional generation planning is adopted.

In regional generation planning, the objective function is to minimize the cost of generation investment and production to the customers in the region over a planning period, subject to reliability, environmental and financial considerations. The total costs and benefits of the resulting generation plan will be allocated on an equitable basis to the participating utilities comprising the region.

Criteria for Model Evaluation

The criteria for model evaluation can be grouped under five categories, namely, (1) Generation Alternatives, (2) Methodology, (3) Production Costing, (4) Problem Formulation, and (5) Computational Requirements. Each of the categories of criteria will now be described from the viewpoint of desirable characteristics for application to regional generation planning.

Generation Alternatives:

Generation alternatives are the options considered by the models in their optimization procedures for satisfying future expansion at minimum cost. For a single utility, a limited number of alternatives will suffice. For instance, within the class of nuclear units, one particular unit size may be sufficient to consider for an expansion period of ten years. However, for regional planning, each

participating utility may have its own optimal unit size. Coupled with other distinguishing features like different capital cost and fuel cost, a region may require a large number of generation alternatives.

In addition to the number of alternatives, the types of alternatives that can be considered by the models are also important. For some regions, hydro and pumped storage are not realistic options, however, they may form a major portion of the generation mix in other regions. The complete set of generation alternatives that are desirable for general application should include the following:

- Hydro
- Pumped storage and other advanced storages
- Thermal generation
- Unconventional generation
- Firm purchases

Methodology:

Under this general category, four criteria are included, namely,

- Method of solution
- Problem size
- Sensitivity analysis
- Availability of suboptimal plans

The method of solution refers to the mathematical technique used in solving the generation expansion optimization. Depending on the desired optimality, accuracy, and computational speed, several methods of solution are available. No single method has a distinct advantage over others for application to regional planning.

Problem size that can be handled by the models is an important consideration for regional planning. An inherent capability to perform problem size reduction is desirable. The ability of a model to provide sensitivity information or to permit efficient execution of sensitivity cases is very useful for planners. Of great value also is the availability of suboptimal plans which can provide a wider spectrum of candidate plans for final selection.

Production Costing:

The criteria under the category of production costing concern the modeling of important variables for estimation of production cost. They are listed as follows:

- Load representation
- Hydro and pumped storage modeling
- Treatment of unconventional generation
- Treatment of maintenance

• Treatment of forced outages

Problem Formulation:

This category of criteria concerns the comprehensiveness of the problem formulation. They are designed to evaluate the factors that are either represented as constraints or part of the cost function for minimization. Considering the impact these factors may have on the resulting optimal plan, they share equal importance with the Methodology and Production Costing criteria. They are:

- Reliability
- Environmental effects
- Time horizon
- End effects adjustment
- Interface with transmission planning

Reliability and environmental effects may be modeled as constraints or part of the objective function. The time horizon that a model can handle may restrict its application to long-term regional planning. The end effects can influence the optimality of the expansion plan in several years before the terminal period. Since there exists a coupling between generation and transmission planning, for a globally optimal expansion, it is necessary to iterate between the generation and transmission plans. Therefore, a well-defined interface is desirable.

Computational Requirements:

Although future computer capability may be so unlimited that computational requirements are not an important consideration, in the near term, there are practical limits to the affordable computer resources that can be devoted to generation planning. For this reason, it should be considered as a criterion.

MODEL EVALUATION

In this section, the six models are evaluated and compared according to the criteria discussed previously. The most interesting comparisons are summarized in Table 1. The evaluation consists of delineating the capabilities, limitations and assumptions of each model and proceed by criteria.

None of the models is directly applicable to multiple utility regional planning problems although it may be possible to adapt them for this purpose. Assuming the problem size is manageable, the important issues become the question of the reliability of interconnected areas, cost allocation, and multi-area generation dispatch. Furthermore, the objective of regional planning is not necessarily the sum of total discounted costs for all utilities, due to complicated institutional factors and the inevitable issue of equitable sharing of costs and benefits over the geographically distributed service area.

Alternatives for Generation Expansion

All six models include the capability to automatically select a generation expansion plan from a set of alternative sources of generation. All models can handle thermal generating units as alternatives. That includes nuclear, coal, oil, gas and combustion turbines. The MIT Model also has the unique capability of characterizing the generation alternatives by thermal and air pollution abatement technology and their emissions.

With the exception of the MIT Model, hydro generation cannot be automatically selected by the models for generation expansion. The difficulty of this is due to the site-specific characterization of hydro units and site availability. The MIT Model incorporates a hydro site constraint.

Pumped storage hydro, being similar to regular hydro, is not included in all models as an alternative. The University of Massachusetts Model, WASP, and the MIT Model do, but OPTGEN, PUPS and the EDF Models do not. However, it should be noted that PUPS and the EDF Models permit the simulation of prespecified additions of pumped storage.

Unconventional generation sources like solar, wind, tidal power, etc. which are highly intermittent cannot be automatically included as an alternative for expansion in any existing model. PUPS was specifically designed to study the system benefits of an intermittent generation source like tidal power. It is, however, only a simulation model as far as the expansion of tidal power is concerned. Still, it allows important questions like energy credit and capacity credit to be answered.

For some utilities and for regional planning, firm purchases are often one of the economic options of meeting load growth. Firm purchase is a difficult alternative to model because of its dependence on the generation plans and demand forecasts of neighboring systems. Firm purchase is available only during those years when the neighboring system has excess reserve capacity, therefore, a firm purchase contract usually has a limited duration. This temporary nature of firm purchase distinguishes it from other generation alternatives. If the firm purchase is in the form of joint ownership with a fixed percentage of capacity, it may be approximately treated as a regular generation alternative. If it is a utilization of the neighbor's surplus capacity, then none of the six models can consider it as an expansion alternative.

Methodology

The models are compared under the sub-headings of Method of Solution, Problem Size, Sensitivity Analysis, and Suboptimal Plans.

Method of Solution:

The objective functions (sum of operating and investment costs) for the University of Massachusetts and MIT Models are similar. They are both linear in the number of capacity installations by type, vintage, and time. Mixed integer linear programming and

Table 1. Comparison of Generation Planning Models

MODEL	U. Mass.	MAST	OUTER	HCT	EPF	EPBS
CRITERION						
Generation Alternatives Available						
Hydro	No	No	No	Yes	No	No
Storage	Yes	Yes	No	Yes	No	No
Thermal	Yes	Yes	Yes	Yes	Yes	Yes
Unconventional	No	No	No	No	No	No
Purchases	No	No	No	No	No	No
Methodology						
Solution Method	Mixed Integer Linear Programming	Forward Dynamic Programming	Forward/Backward Dynamic Programming	Linear Programming	Steepest Descent applied to Max. Principle	Screening Curves
Problem Size	Limited	Limited	Limited	Limited	Limited	Unlimited
Sensitivity Analysis	Yes	No	No	Yes	Yes	No
# of Suboptimal Plans Available	0	10	100	0	0	0
Production Costing						
Load Representation	Load Duration Curve	Load Duration Curve	Peak & Total Energy Demand	Load Duration Curve	Load Duration Curve	Hourly Load Data
Modeling of Hydro	Yes	Yes	No	Yes	Yes	Yes
Modeling of Storage	Yes	Yes	No	Yes	Yes	Yes
Provision for Unconventional Sources	No	No	No	No	No	Yes
Treatment of Maintenance	Derate	Heuristic	Derate	Mixed Integer Linear Programming	Optimize	Derate
Treatment of Forced Outages	Derate	Equiv. Load Duration Curve	Derate	Equiv. Load Duration Curve	Monte-Carlo Simulation	Derate
Problem Formulation						
Reliability Treatment	Approx. Distribution	Equiv. Load Duration Curve	Approx. Distribution	Reserve Margin	Penalty Cost	Equiv. Load Duration Curve
Environmental Effects	No	No	No	Yes	No	No
Length of Planning Horizon (yrs.)	10-20	10-30	10-20	10-20	10-20	10-50
Accounting for End Effects	Extend Evaluation Period	None	Adjust Capacity and Extend Period	None	None	Extend Evaluation Period
Transmission Planning Interface	None	None	Select Plant Sites with Transmission Costs	None	None	None
Computational Burden	Moderate	High	Moderate	Moderate to High	High	Low

Bender's decomposition principle are applied to the University of Massachusetts Program, taking into account the separable operating and investment decisions. MPSX (Mathematical Programming System Extended) is used by the MIT Model to perform the revised Simplex Method on the linear program whose coefficients are provided by a simulation program.

Dynamic Programming (DP) is employed in the WASP and OPTGEN packages. WASP uses forward DP while OPTGEN uses both forward and backward DP. In forward dynamic programming, each feasible generation expansion configuration at each stage is identified with a sequence of unit capacity additions which yields the minimum cumulative expansion cost up to that stage. OPTGEN affords the opportunity to explore suboptimal plans by the use of backward dynamic programming. Associated with each configuration at each stage is a sequence with the minimum cumulative cost of expansion that will be incurred from this state until the end of the expansion period.

Nonlinear programming is applied to the Optimal Control Problem formulated in the EDF Model. The nonlinear function of the configuration (operating cost) is provided by the simulated production cost.

PUPS uses a static optimization procedure involving production cost simulation, screening curves and existing generation mix to determine capacity additions required.

Problem Size:

Due to the large number of production cost simulations involved in dynamic programming, the number of possible generation expansion configurations in any year is limited to 200 in the case of WASP and a truncation algorithm is used in OPTGEN to eliminate plans which are costly in the interim between the initial and final periods of the study. In this latter case, the maximum number of states for any year is 200 and the number of generation alternatives can not be more than 5. Limitations in scope of all the models except PUPS are due to their dynamic nature and the geometric growth in computation as states or stages increase.

Sensitivity Analysis:

A useful feature for power system planners is the sensitivity information provided by the dual variables in the models solved by linear programming. Thus, for example, in the MIT Model, the effect on the cost of providing electricity of the constraints on the number of plant sites corresponding to capacity size can be determined.

The EDF MNI Model computes the co-state variable of the optimal control problem which can be interpreted as the "value of use" of a certain equipment addition. It is in fact the sensitivity of the total system cost to the incremental change in that equipment capacity.

The University of Massachusetts Model can be rerun starting from a base case solution to answer the "what-if" type of sensitivity analysis while

using only 20 to 40 percent of the normal computer time to solve a base case.

OPTGEN can be executed in a simulation mode in which the optimal plan or any specified plan can be simulated without solving the optimization problem. This permits repeated runs of the program for sensitivity information and must be rerun for a change of parameter.

Suboptimal Plans:

Corresponding to the sensitivity feature of linear programming is the feature of the dynamic programming models (OPTGEN and WASP) that allows direct output suboptimal plans without additional computation since the simulation for these cases is already performed in the optimizing process. There is a difference in the approach of WASP and OPTGEN in deriving the suboptimal plans. WASP computes the n-best (up to 10) alternative expansion paths up to a given generation configuration during the forward DP. At the end, the true n-best plans are derived. However, in practice, these 10 best plans are nearly identical to one another except for small deviations, mostly in the last few years of the expansion period. The value of these suboptimal plans is therefore questionable.

OPTGEN does not generate the true 100 consecutive best plans. However, by combining forward and backward DP, it can generate a vast number of plans which are made up of suboptimal trajectories. These plans are simply sorted in order of their costs to provide the 100 best plans. An algorithm is also available to discard plans that are similar with the exception of differences occurring in a specified number of ending years. Results show that these plans exhibit a much wider range of generation mix.

Production Costing

The methodologies of the models in production costing are compared under the topics of load representation, hydro and pumped storage modeling, modeling of unconventional generation, maintenance scheduling, treatment of forced outages, and cost computation.

Load Representation:

A majority of the six generation planning models use load duration curves in the production cost simulation. WASP represents the curve as a 5th order polynomial while the University of Massachusetts Model treats it in a linear programming fashion; the duration parameter specifies the number of hours load demand is above a certain level. The EDF MNI Model also uses a discrete load duration curve with 10 levels corresponding to well-known periods of the day. OPTGEN uses a trapezoidal approximation of the generation duration curve based on the specification of peak and total yearly electric energy demand.

PUPS performs the simulation of non-thermal generation dispatch, i.e., hydro, pumped storage and unconventional generation, on the hourly load data

over an entire year.. The resulting thermal load is converted to an annual load duration for production costing.

Hydro and Pumped Storage Modeling:

Two of the models (University of Massachusetts and MIT) treat hydroelectric and pumped storage plants in a similar manner. The constraint set of the linear program includes the demand placed on the system by pumping in addition to consumer load demand. Both model the storage plant by an efficiency parameter. The University of Massachusetts Model includes a constraint which ensures water levels are returned to the same level at the end of the period with which they began. Siting constraints are included in the MIT Model so that the total capacity of hydro plants in specific locations is limited by water flow, temperature, surface discharge, and loading standards.

PUPS uses the weekly load duration curve for simulation as the peak is shaved by hydro energy. An iterative approach to the determination of the pumped storage charging schedule is found by valley filling subject to energy storage capacity constraints. At the end, hourly schedules are derived.

All hydro units must be combined into a single unit in the WASP and the EDF MNI Models. WASP affords the capability of dividing capacity into two blocks for base loading and peak shaving; in addition an emergency category may be defined allowing for units out of service to be backed up by hydroelectric plants. The more detailed GRETA Model of EDF represents the hydro system by three equivalent units (seasonal, weekly, and run-of-the-river) and allocates energy differently in each case. Pumped storage, aggregated into weekly and daily cycle units are scheduled by a linear programming iterative suboptimization.

Modeling of Unconventional Generation:

PUPS provides the only model in which unconventional electric generation can be treated. Either an unconventional source may be used to supply load just above the must-run generation or storage devices can be employed for retiming. Another important feature is the capability of selling residual unconventional generation in a secondary market, such as to another power system. Although the model was specifically developed for tidal power, any intermittent generation sources can be simulated, provided an annual sample of hourly generation output can be specified.

Maintenance Scheduling:

Derating is the simplest way of modeling maintenance requirements for production costing. The capacity is effectively reduced by the fractional amount of maintenance required, but no account is taken of strategic policies which enable other units to cover the outages in an optimal manner. OPTGEN and PUPS use this derate capacity in the stacking of units under the load duration curve, while the capacity as derated appears in the constraint set of the University of Massachusetts Model.

WASP classifies generating units by their capacity magnitude to limit the number of scheduling variables. The equivalent maintenance blocks are scheduled in the sequence of decreasing size, each time fitting a maintenance block to the period of greatest remaining reserve.

Both the MIT production cost model and the EDF MNI Model feature optimized maintenance scheduling; where, in the latter case, the maintenance scheduling variables are included in the set of decision variables and, in the former case, shutdown can be accomplished for either economic or environmental reasons. In the EDF GRETA Model, because it is a Monte Carlo simulation, the maintenance schedule is prespecified input data.

Treatment of Forced Outages:

As in the case of maintenance scheduling, derating is a popular method of accounting for losses of generating capacity due to unplanned outages. PUPS, University of Massachusetts and OPTGEN use this approach. Actually, this possibility is a random variable which is conveniently represented as a Bernoulli process in an approach referred to as the equivalent load duration curve method. Both the WASP and MIT Models use this approach. Monte Carlo simulation is used by the GRETA Model where samples of available thermal capacities are drawn using the Markovian assumptions.

Cost Computation:

Of the models surveyed, three use annual fixed charges to compute the capital cost. OPTGEN, PUPS and EDF use this approach. The University of Massachusetts, MIT and WASP models are similar in that they represent investment cost by a single cash outlay at the initial period when the plant goes on line. Institutional factors accounting for preference between domestic and foreign capital are modeled by a weighting coefficient in WASP.

Problem Formulation

Under this category of criteria, the models will be evaluated according to their ways of treating reliability, environmental effects, time horizon for the planning period, adjustment of results to account for end effects and their interface with transmission planning.

Reliability:

Two popular approaches to characterize reliability are:

- (a) Reserve margin and
- (b) Equivalent load duration curve.

As a byproduct of the production simulation using the equivalent load duration curve (ELDC), the Loss-of-Load Probability (LOLP) and expected unserved energy may be computed. In the case of WASP, these may then be applied to restrict the state space. OPTGEN approximates the cumulative distribution of forced outages by four log-linear segments and

computes the LOLP. MIT uses a reserve margin parameter in the constraint set to determine the amount of over-supply. EDF models failures as a cost which is added to the operating and investment costs in the objective function. The University of Massachusetts Model uses an analytical approximation of the reliability function based on the mean and variance of the total available capacity, similar to the OPTGEN approach.

Environmental Effects:

The effect on the environment is considered only by the MIT Model. Fuel availability, site-capacity restrictions, new unit addition rate, stack emissions, air quality, river flows, temperatures, lake loading and surface discharge are limited by the constraints in the model. More detailed modeling over a limited time period is provided in a nonoptimizing production model.

Time Horizon:

A practical upper bound for the time horizon for all models but the static PUPS is about 10 years since computation time increases geometrically with the study period length for these models. Computation time is linear in the length of study period for PUPS and the study is limited only by uncertainties about future demands and prices. Fifty years is a reasonable upper bound in that case. If one accepts time steps of more than one year, the EDF MNI Model can solve for a longer expansion period. Likewise, the expansion period may be up to 30 years using WASP if one accepts the possibility of deriving only a suboptimal plan by means of arbitrarily reducing the state space for the dynamic programming. Another artifice is that of decomposing the expansion period into overlapping sub-periods and solve for each period sequentially with coupling through the initial conditions, as was demonstrated by an application of the University of Massachusetts Model. Again, optimality is not guaranteed in this case.

End Effects Adjustment:

End effects in a model account for differences in capacity of alternative plans at the terminal point of the study period. One way of considering these is to artificially extend the planning period by a number of years called the evaluation period in which the system is in steady state, i.e., no increases in aggregate demand or changes in the generation system. The length of this extension is an input parameter in PUPS, whereas it is equal to the maximum immature period of all generation alternatives in the case of the University of Massachusetts Model. The OPTGEN package also allows for the fixed costs for units in the terminal year to be prorated according to the adjusted capacity which will result in a specified LOLP level. The adjusted cost of the terminal year is then projected for the evaluation period and added to the objective function for optimization. WASP, the MIT Model and the EDF Model do not account for end effects.

Interface with Transmission Planning:

OPTGEN is the only model that provides an

interface with transmission planning by modeling the site-related transmission cost. A site is characterized by a staircase cost curve which relates transmission cost to generation capacity at the site. In the forward dynamic programming step, new generating units are automatically assigned to sites where the incremental transmission cost is least. Transmission fixed charges are added to the operating and investment costs of the expansion plans. This approach is a suboptimization which does not account for dynamic effects and it requires the pre-specification of site-related transmission costs.

Computation Requirements

Many models require the use of a number of sub-models serving various functions. When operated in a modular fashion, analysis may be cumbersome and time-consuming. Separate models to define unit types, describe the load duration curve, configure the expansion plan, simulate the system and optimize the plan are required for WASP. Similarly, the EDF package requires the use of an intensive production costing simulation to check the optimizing program after a plan has been determined. The integrated MIT Model consists of two iterative sections - one uses operating data to optimize the configuration and the other finds the optimal operating strategy given the configuration. A detailed production cost model is also included. The large linear programming problem in the University of Massachusetts Model is subdivided and solved iteratively. PUPS features sequential rather than iterative operation of its subprograms with a consequent decrease in user-imposed burdens. Core storage requirements for WASP, PUPS and OPTGEN are at least (30-60K words) while the University of Massachusetts requires somewhat more (100K words). A source of difficulty may be the presence of round-off errors which arise in linear programming as in the University of Massachusetts Model and the MIT Model. This problem may also arise in the solution of the optimal control problem in the MNI Model of EDF.

Since computational requirements are difficult to compare without resorting to benchmark studies, a qualitative comparison is made. WASP and the EDF models require the highest computational burden. Next comes the MIT Model, followed by approximately equal computational requirement by the University of Massachusetts Model and OPTGEN. PUPS requires the least computation.

RECOMMENDATIONS FOR RESEARCH

Based on the survey and the comparative analysis of six generation planning models, certain deficiencies of the state of the art as applied to regional generation planning have emerged. They are classified into near term and long term research areas and described below. Those labeled near term should require less mathematical development and less computational breakthrough than those classified as long term. Since the relative importance of these research topics are somewhat subjective, the order in which they appear below does not reflect any ranking.

Near Term Research Areas

- (1) Comprehensive Expansion Alternatives: With the increasing interest in unconventional generation resources like solar and wind power, and also in load management which includes customer load management as well as supply management, a larger number of alternatives for satisfying expanding electricity demand will have to be considered, especially for regional generation planning which may encompass a service area larger than that of a single utility. Future research should consider the modeling of these emerging resource options in the context of generation planning and develop more powerful optimization methods.
- (2) Problem Size Reduction: In the near term, before more powerful computers or mathematical techniques are available, it will be necessary to reduce the problem size by means of equivalent representation, space or time decomposition, etc. for present methodologies to be practical for regional applications.
- (3) Cost and Benefit Allocation: In real life, cost and benefit sharing is practiced by the utilities that coordinate their planning. However, these practices should be reflected in the generation planning models to facilitate the process and to allow individual participants to know their own cost and benefit readily.
- (4) Planning Under Uncertainty: The state of the art in generation planning already includes modeling the uncertainty of generation outages, hydro inflows and load. Other factors like construction delay, major disruptions of fuel supply, etc. are not yet incorporated in existing models for automatic generation expansion. In terms of their consequences, these uncertainties could be equally or more important than those already modeled.

Long Term Research Areas

- (1) Integration With Transmission Planning: Combined generation and transmission planning would be a very useful technique if it is practical and sufficiently accurate. It would then eliminate the necessity of manual

iterations between the two planning processes and would provide assurance of an optimal expansion plan for both.

- (2) Integration With Regional Energy Model: At the present, generation planning is an open-loop process. The effect of the cost of electricity on the load forecast is not considered. In addition, the cost of fuel is considered to be given and unaffected by the region's fuel consumption, a major part of which is for electric generation. To complete the loop, the generation planning model should be integrated with a regional energy model which should contain a load forecasting module.
- (3) Generation Planning With Multiple Objectives: The MIT Model considers the environmental-economic trade-off for generation planning. It is one step towards developing methods for planning with multiple objectives. In the case of regional planning involving multiple decision makers, it may be necessary to take this approach. Recent mathematical developments in game theory and fuzzy sets may be applicable.
- (4) Extension of Objective Function to Include Social Costs: If the regional planning entity is mandated to optimize the social costs, it would be necessary to consider them in the objective function. The approach of including a cost of unserved energy by EDF is one step in that direction. But other costs, such as employment, taxation, etc. should also be considered.

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SECTION 5.

TRANSMISSION

The Public Service Electric and Gas Company report addresses the planning problems in the areas of network analysis, reliability analysis and institutional issues. Specific models and methodologies are discussed. An extensive bibliography is added (154 references). Also 11 appendices are included.

In the network analysis, a discussion of load flow is presented first and a comparison between the direct and the iterative methods is presented. The data uncertainty and its impact on the calculations is discussed as a stochastic load flow.

Transient stability is considered next. It is considered as an essential part of power system planning for reasons of system security and reliability. The most important equipment in the system with regard to stability is the synchronous machine. Many stability programs have provisions for synchronous machine models of varying details. Recent studies have indicated that detailed models do not increase the modeling accuracy compared to the use of standard data. This area is currently, fully explored using modified machine data under a contract from EPRI. A comparison between various stability models is presented.

A discussion of dynamic stability follows, in which it is stated that a more efficient and reliable method of assessing dynamic stability is required for system security. Different linear and nonlinear analytical methods are presented. A Westinghouse model is discussed. Subsynchronous oscillations are discussed briefly, where the three principals are, generator self excitation, interaction between self excited oscillations and the mechanical torsional movements of the shaft, and combined generator and turbine rotor hunting. It has been indicated that the analysis of the subsynchronous resource problem is more complicated than the transient and dynamic stability problems. A state-space representation of a single machine system is illustrated in Appendix C-3.

Short circuit calculations and its importance is included. A number of methods of network analysis are suggested, e.g., the bus impedance matrix and Thevenin's theorem. The details of the transfer impedance matrix building algorithm is given in Appendix D.

A successful operation of a power system requires consideration of economy, system security and reliability. Some examples and models of static

optimization, i.e., power flow solution under some constraints and a specified optimizing criterion are given. Unconstrained optimization problems are discussed in Appendix E as Carpentier's and BPA approaches. Nonlinear programming techniques are used to solve the constrained case.

The analysis of high voltage transmission by DC method rather than AC methods is examined. Several DC models are discussed and included in Appendix F.

Reliability analysis and methods of evaluation of transmission systems are covered next. Appendix G treats seven approaches to compute a reliability index. It has been mentioned that most approaches have not yet been applied widely by industry on large systems. This is mainly due to the lack of data collection, consistent reliability indices and reliability benefits.

The last section deals with the institutional issues, which are related to inter-company and inter-pool planning. A cost allocation concept is discussed in Appendix H. A brief comparison between various computational tools is included. First, Digital vs. Hybrid computers and their use in analyzing dynamic system stability; followed by batch data input vs. interactive graphic system.

The University of Florida report assesses the state of the art in transmission system planning in the context of regional planning. Tools considered are those for corridor/route selection, capacity expansion planning, reliability analysis, network analysis, and simulation methodology. The report has five appendices and provides 25 references.

In this report, only issues that pertain to the planning of transmission systems on a regional basis are considered. Thus, no emphasis is given to sub-transmission or distribution system planning.

To define the regional planning system, the region is defined as a collection of pools where each pool is a collection of areas and each area is a collection of units. Therefore, the transmission region is defined as that collection of pool and area transmission networks which enable inter-connected utilities to realize the benefits of regional operation. Six major transmission assumptions about long range planning are identified.

The first part of the report treats the regional energy analysis models, and then route identification

is discussed, where analysis tools that are more abstract in scope than the ones used by utilities are involved. A composite corridor map is developed as a first step in establishing transmission corridors which may lead to sophisticated graphical methods. Several line-specific parameters are considered to choose a suitable corridor. Two codes are compared for corridor identification problem, "Power" developed by VPI and SU and "Trans-thetics" developed by Common Wealth Associates. All these techniques are used by a specific utility and the potential for regional use is not explicitly considered.

Capacity expansion planning computational tool is discussed next, where the power-flow analysis is identified as the only tool. Several network analysis algorithms are presented and evaluated.

Reliability analysis is introduced. Several approaches to determine the reliability of the transmission network are discussed. Mainly, conditional probability approach, power flow analysis, automatic contingency evaluations, and graph theory technique.

Network analysis where network equivalencing schemes are utilized to evaluate the overall performance of a given network is discussed next. For regional studies, pool level studies may be required along with equivalencing studies to measure the impact on the interactions between areas in a given pool. Also, at regional level, studies will not require area level detail. Both static and dynamic equivalencing schemes are discussed. A new approach (REI) for static network equivalencing is discussed thoroughly and compared to the existing ones. The dynamic problem involves, identifying coherent groups; eliminating both load and generator busses; aggregating the dynamics of the units in a coherent group. A coherent-based dynamic equivalents represents a viable alternative to the transient stability analysis.

Simulation methodology is then discussed in more detail. This section is motivated by the fact that in regional planning design methodologies and philosophies a trade-off of various expansion plans have to be determined. Techniques which include uncertainty are discussed, e.g., linear programming under uncertainty, stochastic programming, multi-level optimization, and vector optimization.

The Power Technologies, Inc. report discusses the state of the art of computational tools for large-scale transmission system planning. Load flow and dynamic simulation, reliability analysis, and automated transmission system expansion are the topics treated for this planning process. The report contains twelve appendices and provides 59 references.

The regional planning process is defined as the problem of determining the location, kind and timing of facility additions that will meet the predicted load demand in the future. The objective is to minimize investment and operating costs within the reliability, environmental, and politi-

cal considerations. The transmission planning is performed by defining the following activities: load flow studies, dynamic studies, reliability assessment, and economic comparisons.

In the area of steady state network analysis, both DC and AC load flow programs are discussed. Both iterative and direct methods for the solution of a load flow problem are compared and different approaches are discussed.

The dynamics of power systems is discussed next. The dynamic performance corresponds to such variables as prefault network state, fault location, fault type, fault duration, protection response and generator characteristics. Two direct approaches are recommended even though they are unrealistic when used for precise dynamic analysis of large scale systems. Time domain simulation is proposed for large system. The area of dynamic performance is divided into two areas: transient stability and dynamic stability. Both network analysis and digital load flow programs are compared as an approach to the dynamic analysis problem. Several models and their limitations are discussed in the text and in Appendix 2.

Reliability analysis is presented. First, the need for reliability tools is stressed, then the criteria for defining reliability of the System for both the deterministic and probabilistic cases are discussed. The contingency criterion is presented for the deterministic system and bulk power interruption and bulk power energy curtailment indices are presented for the probabilistic case. Reliability assessment procedures are described. The real power contingency models are presented. In the case of DC load flow a DC load flow solution is recommended. The concept of distribution factors is discussed and its limitation to only one network configuration is explained. Several solution procedures are presented in Appendices 3 and 4. In the case of AC contingency models, three methods are discussed: decoupled Newton load flow, z matrix method, and sensitivity methods.

The probabilistic reliability analysis is covered next. It consist of adequacy and security analysis. Three methods are discussed for adequacy assessment: contingency enumeration methods, composite method and contingency level method.

The Monte Carlo simulation methods are introduced where they allow very detailed modeling in transmission planning.

The concept of effectiveness analysis when there is a balancing between incremental system cost and worth of improved reliability is discussed and described in Appendix 7.

Expansion models for transmission systems are discussed in some detail. For a single period planning problem the gradient search method, linear programming, and integer programming are recommended as approaches and some comparisons are drawn.

Detailed explanations are presented in Appendices 8, 9, and 10 accordingly. In the case of multi-stage planning models both dynamic and integer programming are recommended. Appendix 11 explains the use of dynamic programming. For a heuristic solution procedure, see Appendix 12.

SECTION 5.1

REGIONAL POWER SYSTEM PLANNING ASSESSMENT OF TRANSMISSION PLANNING PROBLEMS

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I INTRODUCTION

This report is the result of an intensive investigation by Public Service Electric and Gas Company, into various aspects of transmission planning on a regional basis. Specifically, the report addresses the planning problems in the three areas of network analysis, reliability analysis and institutional issues, and provides comparative assessments of study methodologies and tools, concise descriptions of the models used and a summary of recommendations of future work that may be warranted. In addition, an extensive bibliography of publications associated with each area is included for further reference.

II DESCRIPTION OF PLANNING PROBLEMS AND ASSESSMENT OF PLANNING MODELS AND METHODOLOGIES

The transmission planning process, simply stated, is to determine when and what new transmission facilities are required and how they should be integrated with the existing network in order to provide sufficient transmission network capability to meet the generating capacity additions and load supply requirements projected for the future. An adequately planned transmission network should provide sufficient network capability for transferring generation output to system load centers, rendering necessary emergency assistance between interconnected areas, and exchanging economy power. The key objective in the planning process is to minimize overall capital and operating costs on a long term basis while maintaining a specified acceptable level of reliability, with due consideration of environmental and institutional issues.

The regional transmission planning process then is to accomplish the above stated goals on a multi-company or multi-area basis with the inherent increase in complexities of system configurations and institutional issues, such as allocation of rights and obligations of multi-party interconnections and joint transmission

projects and coordination of bulk-system reliability criteria.

Detailed descriptions of the various areas of transmission planning functions are covered in the following text.

II-1 Network Analysis

II-1-A Load Flow - Load flow is the solution for the static operating conditions of an electric power system. Load flow calculations are performed for power system planning, and in connection with system operation and control. The basic problem involves the solution of a series of non-linear equations.

The different methods that have been used are all iterative in nature. However, the methods that employ the direct solution of a related linear system in the overall iterative algorithm are commonly referred to as direct methods. Impedance matrix methods and the Newton methods are examples of direct methods, whereas the iterative methods such as Gauss-Seidel employ a scheme of successive displacement. In general, direct methods converge in a few iterations and can handle ill-conditioned situations satisfactorily. However, their storage requirement is large and, generally, the computing time increases greatly as the problem size increases. The iterative methods converge slowly and are subject to failure in certain ill-conditioned situations, and although their storage requirement is significantly smaller and directly proportional to problem size, the number of iterations per solution increases rapidly with problem size. The first successful method to be applied to the solution of power flow problems was the Gauss-Seidel iterative method, and was proved to be the only practical method for large problems during the early days of the application of computers to power systems due to its minimal storage requirement. Load flow programs based on the Gauss-Seidel algorithm are still in use in many utilities and industries. Also, many stability programs use this

method to solve the load flow portion of the overall stability calculation. Because of its continued usefulness and its historical importance a brief description of the Gauss-Seidel method employing nodal admittance matrix is included in Appendix A-1. The slowly converging behavior of the Gauss-Seidel method and its frequent failure to converge in ill-conditioned situations led to the development of the Z-matrix methods. Although these methods have significantly better convergence characteristics, many have the disadvantage of requiring a very large computer storage, since the Z-matrix is full and unlike the Y-matrix which is extremely sparse. The main importance of the Z-matrix methods is its use in transient stability calculations as discussed later and its extension to high-speed contingency evaluation. In general, for problems that can be solved by both methods, Z-matrix methods are not competitive with Y-matrix iterative methods because computation and storage requirements become prohibitive for very large problems. By resorting to diakoptics very large systems can be solved by Z-matrix methods. However, since the computer programming is more complex and there is to date no efficient computer method of 'tearing' the system, the method has not been used extensively. As the problem size grows, the need for more powerful methods becomes apparent. Newton's method, originally described by Van Ness and Griffin, showed superiority over other methods in terms of convergence characteristics. However, it remained unattractive on large systems due to the rapid increase of computer time and storage requirement with problem size. The method involves the solution of a system of sparse simultaneous equations. Further research at BPA led to the development of an effective method of solving the simultaneous equations employing an optimally ordered elimination technique.

The greatly increased efficiency of Newton's method for solution of power flow problems has made it the industry standard at present. The main characteristics of Newton's method are its speed and accuracy. The number of iterations required for solution is virtually independent of problem size and kind. For problems with a flat voltage start and without automatic adjustments, an acceptable solution can be obtained in four or five iterations. With a good starting approximation, solution can be obtained in fewer iterations. When extensive program-controlled adjustments such as transformer taps and area-interchange are utilized, and constant checks are required, solutions may require extra iterations. Due to the method's quadratic convergence characteristic, convergence is very rapid when the solution point is

close. The method is very reliable and is insensitive to factors causing poor convergence with other methods. Although Newton's method requires more storage than the iterative methods, the requirement is not prohibitive. With optimally ordered elimination, the storage and time requirements for large systems vary approximately in direct proportion to problem size. Later refinements to include automatic controls and adjustments, such as area interchange control, in-phase tap changers and phase-angle regulators made Newton's method even more attractive.

The need for multiple load flow solutions in certain planning studies and system operation has led to the development of decoupled methods, derived by applying approximations to the formal Newton's method. They provide sufficient accuracy with improved speed and are suitable for on-line applications and contingency security assessments.

Over the years an enormous amount of effort has been spent in research and development on numerical methods and programming techniques in order to establish an optimum way of handling the solution of power flow problems. A basic requirement of any load-flow algorithm is reliable and fast case convergence, but no known method that is fast enough for routine application can guarantee a feasible solution in every case study. However, it is also important that the method does not break down for any physically operable system condition. All three methods cited in the appendix have proven to be highly successful in most applications. For general power flow solutions Newton's methods are certainly the most versatile and they can be considered as the industry standards at present. They have also been used in a wide variety of system optimization calculations. The superiority of Newton's methods is due to better convergence characteristics and, to a greater extent, the development of efficient programming techniques employing optimally ordered elimination.

The sizes of problems to be solved continue to rise at a fast rate. The subject of diakoptics-solution of system problems by tearing the system, which did not seem to be very important after the development of Newton's method into a powerful and practical technique, should receive fresh attention to cope with the ever growing system size. The question of data uncertainty and its impact on the calculated load flows has recently received some attention and this is discussed on the following page under Stochastic Probabilistic Load Flow.

STOCHASTIC/PROBABILISTIC LOAD FLOW

In recent years, some work has been done on the concept of a non-deterministic load-flow analysis. Since several load flow input parameters are inherently uncertain in nature, the load flow solution is an inherently stochastic one, and one in which the resultant branch flows are properly represented by a range of possible values, or mathematically by a probability distribution function.

To date, methods of incorporating these uncertainties into the load flow analysis have focused on adapting statistical techniques toward treating uncertainties in the node data (i.e., load/generation schedules). Although each method has been applied to test systems by the developers, the absence of sufficiently wide applications by planning engineers to analyze real-life large-scale systems does not allow conclusive statements to be rendered regarding the preferability of any one method or the potential adaptability of any method to future, more extensive stochastic load flow models. Further details are discussed in Appendix A-2.

II-1-B Transient Stability - Stability considerations are recognized as an essential part of power system planning and operation. In the early days of power system growth, acceptable stability performance could be achieved without much difficulty. With the growth of interconnections and generator sizes, primarily in the last two decades, system stability has become one of the major concerns. For reasons of system security and reliability it is important that the stability characteristics of a large power system are understood and evaluated under a variety of disturbances involving faults, loss of generation, loss of load, loss of transmission facilities, etc. A successful prediction of stability behavior of a large interconnected power system is extremely involved. It may require adequate representation of many generators, often numbering several hundred, along with their control equipment, the associated transmission network and all the major loads that can influence system dynamics during a disturbance.

Much of the effort in the field of stability studies has been spent in developing adequate mathematical models for the various components of the power system. The most important equipment in the system with regard to stability study is the synchronous machine. A number of different representations differing in degrees of detail have been used over the years. The earlier stability programs used a simplified generator representation, the classical constant voltage behind transient reactance model.

It has been recognized that a more detailed representation is necessary for an adequate simulation of the dynamic behavior of synchronous machines in the transient states. However, different machines are affected differently depending on their electrical proximity to the disturbance. Accordingly, many sophisticated stability programs have provisions for synchronous machine models of varying details for different groups of machines in the system. The synchronous machine models used in transient stability programs designed for large system studies are all derived from the basic 2-axis representation as formulated by Park after applying various simplifications. Unless the study is of a specialized nature involving only a few machines the stator transients are always neglected. The extent to which the rotor transients are included in the model depends on the degree of sophistication required and the available data. Recent studies have, however, indicated that instead of using standard data, an arbitrary increase in modeling details does not necessarily increase the modeling accuracy. However, it is possible to obtain accurate results from a moderately detailed model using modified machine data. This area is being fully explored currently under a research project funded by EPRI, titled "Determination of Synchronous Machine Stability Study Constants".

Increasing modeling details in a large scale transient stability study often does not result in expected increase in accuracy. This is because the errors involved in the simplifications tend not to be cumulative. At the same time, every additional detail in the component representations is made at the expense of increased computing time and the burden of additional data. In the absence of accurate data a less detailed model can be expected to produce equally accurate results. However, modeling simplification should not be made without proper discretion.

A complete representation of a synchronous machine includes representation of excitation and prime mover control systems. These are well standardized for the majority of the systems currently in use and have been documented by IEEE. Again, these should not include any more detail than is necessary. Depending on the nature of loads, their representation can influence the results of any stability study to a greater or lesser extent. Traditionally loads have been represented by constant impedances, not only to reduce the computational burden but mostly due to a lack of precise information about the true nature of load. Work has been done through an analysis of the detailed composition of various

types of load as well as through tests conducted on certain isolated feeders in order to establish a general load model suitable for use in stability studies. But the information obtained can hardly be considered representative of all loads. Most transient stability programs, however, have provisions for representing the three basic load types - constant impedances, constant MVA, and constant current or combination thereof. Where the loads are predominantly induction motor loads and are thought to have considerable influence on the stability of the generators as well as the motors themselves, a detailed induction motor representation in d-q axes similar to that of synchronous machines has been used. Stator transients are almost always neglected. Also, when rotor time constants are small, requiring a very small integration step length, simplified induction machine representation by a steady-state equivalent circuit has often been adequate.

Since the operation of relays during a disturbance can influence system stability, their effects ought to be represented in a stability study. Most transient stability programs have provisions for representing the more common types of relays. Their inclusion does not generally present any significant computing burden but does require significant data input.

Transient stability calculations involve the digital solution of the differential equations representing the machines and the control equipment, alternating with the solution of the network. The load flow problem in transient stability calculations differs from the standard load flow problem in that it is characterized by multiple slack buses representing the machine internal voltages which are temporarily held constant in magnitude and angle. Accordingly, the load flow algorithm must be modified. In fact this actually improves the convergence characteristics of the load flow. Details of such calculations are given in Appendix B. The two methods that have been found most suitable and used by the majority of the transient stability programs are the Y-matrix nodal iterative method and the Z-matrix method. Newton's method, although closely competitive, appears to be somewhat less suitable for transient stability calculations.

Large scale transient stability programs that are currently available can handle several hundred generators and several thousand buses with detailed representations of machines and control equipment. The need for studying systems

even larger than these programs can accommodate sometimes exists. With all the sophistications and refinements in system representations the computational burden is enormous. Any logical way of reducing this burden is always beneficial. There have been attempts of reducing the size of the problem by various means, some of which have been only partially successful. Some work has been done to represent those parts of the system that are not of immediate interest by equivalents. However, a mathematically rigorous way of carrying out this process has yet to be developed. Work has also been done to develop such equivalents using the concept of "coherent groups" of machines. Machines in a coherent group are assumed to swing together and therefore the swing curve of only one machine in that group is calculated. This way it would be possible to study a large system with a smaller representation. However, since coherency can only be established from a stability run based on a complete network representation, it puts some limitations on practical applications of this method of applying equivalents.

Recently there has been a new outlook in the refinement of system component representations. Such representations need not be more complicated in order to obtain more accurate results in the overall transient stability study. Modifications of the design data to match the calculated performance of particular equipment more closely to its test results permit a much simpler and more accurate modeling. The current research on synchronous machine constants sponsored by EPRI is expected to be very rewarding.

One area in which a more extensive research is also needed is in load modeling. Although the computer programs have the capability of representing any given load characteristics, very little is known about the actual behavior of composite loads during a transient system state. Currently a load-dynamics research project is in progress under EPRI funding. A conceptual type load modeling investigation is also under way supported by DOE.

II-1-C Dynamic Stability - Transient stability programs are usually designed to study system response immediately following a large disturbance. The studies are normally limited to a short duration, usually a few seconds. If all the generator rotors swing back before reaching a specified angle the system is considered transiently stable. In the early days when an interconnected network was relatively confined and sophisticated

control equipment was not generally used on the generators, the above criterion, also called first swing stability, was enough to assure ultimate stability of the system against that particular disturbance. With the growth of interconnections and application of advanced control equipment, consideration of proper damping of oscillations became more important. Even though the system is capable of withstanding the initial shock of the disturbance as evidenced by the first swing stability, oscillations could continue at a reduced amplitude for a while, only to increase a few cycles later and eventually cause cascading line tripping and possibly system separation. This particular problem is generally termed dynamic instability and it can manifest itself not only following a major disturbance but also following a sudden change in system conditions not generally classified as major disturbance such as a moderate amount of load shedding, a sudden addition of load or tripping of a weak tie, etc. The problem exists due mainly to inadequate or negative damping in the system which is the result of a complex interconnected network with dissimilar machines in different parts of the system equipped with fast acting control systems whose parameter settings are not properly coordinated. Transmission line parameters can also contribute to poor system damping. Due to its very nature, a dynamic stability study will cover a longer real-time duration. Conventional transient stability programs can be used to study dynamic stability problems by applying a minor disturbance to the network and running the program for a longer period of time than is normally required to establish transient stability. However, this is expensive and really not fully conclusive, due to inappropriate machine models used for such long duration studies.

Although the dynamic stability problem is not common to all large power systems, it constitutes a severe threat to system security and creates difficult operating problems. A more efficient and reliable method of assessing dynamic stability for large systems is therefore required. One important feature of dynamic stability is that the oscillations do not initially involve non-linear behavior in any essential way. Therefore, linearized mathematical models and linear analytical methods may be used to study the problem. Of the several methods of obtaining stability information from a linearized system, the state-space approach has certain advantages. Other methods such as Nyquist's and Routh-Hurwitz's criteria or the root-locus technique are suitable

for application to simple single machine systems, but their usefulness is limited in that they provide very little information on system responses. A state-space approach is preferable since in addition to establishing stability or instability, it also provides information on system responses and their sensitivity to system parameter variations.

In the state-space analysis the system equations after linearization are expressed in state-space form, and eigenvalues and eigenvectors are determined using a standard eigenvalue program. A major part of the analysis in a multi-machine system is the derivation of the state-space model. An efficient method of derivation is described in Appendix C-1. Stability or instability can be determined from an examination of the system eigenvalues. For asymptotic stability the eigenvalues must have negative real parts. For complete information on system responses, an analysis of both the eigenvalues and eigenvectors is necessary as discussed in the appendix.

A method has been developed by Westinghouse to study dynamic stability of large power systems using a frequency response technique. The method deals with low frequency oscillations. The system is linearized and the eigenvalues and eigenvectors corresponding to the low frequency modes i.e., the eigenvalues with the smallest absolute values and the corresponding eigenvectors, are obtained in an iterative manner. However, this method, besides being more complicated, cannot be entirely relied upon since undamped or negatively damped oscillations are not always the low frequency oscillations. The state-space approach which evaluates the complete set of the system eigenvalues would be the recommended method, since it would then be possible to identify with certainty the troublesome negatively damped modes, if any, and devise corrective action. Such a method of obtaining dynamic stability information can be very useful in system planning, primarily in defining stability/instability boundary conditions. Also in a state space analysis, machines in the immediate vicinity of the area under investigation can be represented in full detail. A large number of machines outside and adjacent to this area can be represented by the classical model and the rest of the system can be represented by equivalents. The total dimension of the problem will thus be within the capacity of the eigenvalue analysis programs now available. Although eigenvalue analysis has not been widely used in the industry in the investigational

of stability of multi-machine systems, the method is invaluable and should be fully exploited.

It is not suggested, however, that the state-space approach should be a complete substitute of detailed time-domain dynamic stability analysis. Rather, it would reduce and optimize the time domain simulation studies required. Currently research work funded by EPRI is developing both mid-term (up to 5 min.) and long-term (up to 20 min.) time-domain dynamic stability programs. In addition, an EPRI funded load dynamics project is also in progress. These developments will provide improved machine and load representations, reduce computation time and enable detailed examination of overall system dynamic responses following a disturbance.

Subsynchronous Oscillations

The insertion of series capacitors into transmission systems creates oscillatory electric circuits that have natural frequencies in the subsynchronous range. At this frequency range, a synchronously rotating machine behaves like an induction generator. The amount of energy generated by the induction generator action is a function of the magnitude of the rotor resistance at the subsynchronous or slip frequency. If the system is poorly damped, the machine could feed more energy than is absorbed by the resistance loss in the transmission lines resulting in sustained subharmonic oscillations. The self excited currents may be initiated and grow quite independently of any applied armature voltage of field excitation. In the presence of field excitation, this will interact with the transient subharmonic currents to produce pulsating airgap torques at slip frequency, which will in turn produce rotor oscillations and corresponding shaft torques. This pulsating torque may excite significant torsional movement of the rotor if the slip frequency is close to any of the mechanical torsional natural frequencies of the unit. Furthermore, the rotor oscillations will produce voltages in the armature circuits which will reinforce the self excited currents. Eventually these coupled mechanical and electrical system oscillations may reinforce each other to the point where they become unstable. The shaft torques could build up spontaneously to damaging levels without any large initiating system disturbance.

The three principal aspects of the problem of subsynchronous resonance are:

- 1) generator self-excitation due to induction generator effects.
- 2) interaction between the self excited oscillations and the mechanical torsional movements of the shaft.
- 3) combined generator and turbine rotor hunting.

The third mode can exist without series capacitor compensation and is not really a subsynchronous resonance problem although it can be enhanced by it.

Since the sub-harmonic oscillations start as small oscillations, a basic analysis can be performed on a linearized system. For the purpose of investigating stability a state-space approach is preferable since this method offers more insight into the problem than other methods of analysis as pointed out in the discussion on dynamic stability. The analysis of the subsynchronous resonance problem is, however, more complicated than those of the conventional transient and dynamic stability problems due to the necessity of including the generator stator and network transient effects. A state-space representation of a single machine system is illustrated in Appendix C-3. Since the sub-harmonic oscillation problems generally involve large remote generating stations connected through long distance series capacitor compensated transmission lines to metropolitan systems a single machine analysis is usually adequate. A more general analysis of a multi-machine system will however, be considerably more complicated due to the necessity of handling the generator stator and network transients. Further efforts should be directed towards developing more efficient techniques for analyzing a multi-machine system.

II-1-D Short Circuit - Short circuit calculations determine the voltages and currents which would exist on a power system during fault conditions. This data is required to design an adequate protective relaying system and to determine interrupting requirements of circuit breakers. Relaying systems recognize existence of a fault and initiate circuit breaker action to remove the faulted facility with a minimum of service disruption and equipment damage. The voltages and currents resulting from many types of faults at many locations must be calculated to give sufficient data to develop an effective protection system.

For many years the d-c network analyzer was an adequate tool for short-circuit

calculations. As digital techniques became available a number of methods of network analysis suitable for short-circuit calculations were suggested. The method now in general use throughout the industry involves the bus impedance matrix and Thevenin's Theorem. The matrix is the open-circuit driving point and transfer impedance matrix. If the matrix has been calculated the complete fault analysis can be made with a minimum of arithmetic operations. In subsequent calculations of the network with changes in configuration, the matrix may be modified in a small fraction of the time required to obtain the original matrix.

The details of the matrix building algorithm is given in Appendix D. The matrix is assembled by starting with a system of a single line, adding one line at a time and modifying the matrix for each line addition. Computer programs are available which form the matrix automatically from lists of line, transformer and machine reactances or impedances. After the matrix has been formed, whatever fault calculations are necessary may be simply programmed.

In many short-circuit studies of very large systems the short circuit information pertaining to only a small portion of the system is required. In such cases, it is possible to build and work with only the portion of the complete bus impedance matrix corresponding to the study area. This allows the study to be carried out on a smaller computer and greatly reduces computer time. However, if such studies require handling the complete system or a major part of the system such that the saving through a system reduction is minimal, the matrix building algorithm may prove to be inefficient. A great savings in computer time and storage can be achieved by working with the bus admittance matrix. The solution of the short-circuit problem can then be obtained by an optimally ordered triangular factorization of the admittance matrix, taking full advantage of its sparsity.

If the fault under study produces an unbalanced system the method of symmetrical components is generally used. In analyzing three-phase short-circuits, the behavior of the balanced system is computed by means of the bus impedance matrix of the positive sequence network. In practical systems either three-phase or single-line-to-ground faults are almost always limiting conditions. In single-line-to-ground calculations the three sequence networks are connected in series. Generally the negative sequence matrix is considered identical

to the positive and is never computed. The building of the zero sequence matrix is complicated by the existence of magnetic couplings between lines in the zero sequence network. The building algorithm must include the effect of the coupling at the time a line is added, if it has coupling with a line already in the matrix. Otherwise, the matrix building process is identical to that for the positive sequence. Once the matrices have been formed, the fault calculations may be rather simply programmed. When the total sequence current is known, a line current may be found by calculating the positive and zero sequence components independently, including the mutual effect in the zero sequence case, and combining these results.

The basic method described is a necessary part of programs for circuit-breaker duty calculations, circuit-breaker and fuse co-ordination studies, relay studies and other related programs. It has been in general use for a number of years and has gained almost universal acceptance. It is flexible, simple to use, and highly accurate. Although other methods such as a Gauss-Seidel iterative approach and a loop impedance matrix approach have been used, no method other than the bus impedance matrix approach seems well suited for general, large system studies.

II-1-E Static Optimization - A successful operation of a power system requires considerations of economy, system security and reliability. To ensure satisfactory operating performance, certain specified constraints should be met. Proper system planning should recognize that such operating performance can reasonably be attained.

Power system static optimization refers to the power flow solution that satisfies these constraints and optimizes certain performance criteria. An objective function, depending on the particular problem at hand, may be defined and the optimum function (minimum) may be found by a suitable optimization technique. A special case of the general static optimization is the classic economic dispatch where the total fuel cost is minimized by optimizing the real power generation. The most widely used approach to the solution of the classic economic dispatch problem has been through the use of the so called 'B' constants, because of its simplicity and ease of implementation for on-line control. The method is, however, approximate. Some improvement over the 'B' constant method was implemented by

AEP, where it was also extended to incorporate reactive power dispatch. Attempts to improve upon the classic economic dispatch led to the development of optimal load flow. An optimal load flow is a load flow in which an objective function (total operating cost or some other quantity) is minimized subject to the ordinary load flow constraints or any other additional constraints. When the objective function represents the operating cost, the solution is an optimum economic dispatch. Much of the work in optimal power flow, subject to equality and inequality constraints, has been based upon the Kuhn and Tucker theorem of non-linear programming. The original work of Carpentier on optimal power flow based upon the Kuhn-Tucker theorem proved to be much more difficult and erratic than was initially recognized. A different computational approach was developed at BPA taking advantage of their existing power-flow program employing Newton's method. This method proved to be highly successful. Both Carpentier's and BPA approaches are summarized in Appendix E.

The optimization problems have also been solved by non-linear programming techniques developed in recent years. The power system optimization problem formulated as a constrained minimization problem is transformed into an unconstrained problem. One of the available powerful methods for unconstrained minimization can then be applied to obtain a solution. However, these methods do not appear to be suitable for application to large power system optimization due to problems associated with reliability of convergence, speed of solution and core storage.

The planned installations of reactive sources and the appropriate control of reactive power and system voltage are essential for maintaining the service quality of electric energy supply to customers, and reducing transmission system losses. An optimum allocation of reactive bus power can maintain system voltages within proper tolerance during normal and various contingency conditions as well as reduce operating cost through the reduction of transmission losses. Voltage and reactive power optimization can be carried out through an optimal power flow by selecting an appropriate objective function which reflects the type of optimization desired, subject to the specific constraints. However, if the objective is an optimized allocation of reactive sources e.g., capacitors, in

order to maintain voltage levels in contingency conditions, other less elaborate methods may be used. Two of the methods of allocating capacitors in a transmission system that seem to be practical are based on linear approximations. These are summarized in Appendix E. One method uses linear programming to carry out the optimization, and the other selects the buses for capacitor locations through a dynamic measure of sensitivity.

The classic economic dispatch using approximate loss formula in terms of the 'B' constants or its later improvement through a more rigorous loss calculation has found extensive use in the utilities in the past and it is still the method of prevalent use today. The large amount of work that has been performed in the area of non-linear or full optimization with the inclusion of additional constraints has established its advantages and the extra gain that may be obtained from such an approach. However, the benefit of using a more rigorous and generalized technique should be properly weighed against the extra computing complexity. Of the several full optimization methods now available, only the one developed at BPA seems to be suitable for application to large systems and it is also of sufficient generality. However, future improvements in non-linear programming techniques and changes in the problem formulation might make other methods more attractive. Further research is warranted in this area.

II-1-F DC Simulation

Recent interests by utility planning engineers in applications of high voltage direct current (HVDC) transmission facilities as possible alternates to EHVAC in their transmission expansion plans, have prompted an increased concern of incorporating DC representations into existing AC network analysis computer programs.

Incorporation of HVDC representations into load flow programs is not essential in itself since power flows on point-to-point DC lines for a specified steady-state condition are normally fixed, and can be simply and adequately represented in most cases by block-loading in AC load flow.

But for the purpose of transient and dynamic system stability studies, a more rigorous DC transmission system representation is required - one which correctly depicts the dynamic responses

of DC system control and the dynamic interactions between the AC and DC systems during and after system disturbances.

There are existing production grade computer programs which contain reasonably detailed representations of DC lines, conversion and control equipment for two-terminal DC transmission lines. (Some additionally have the capability of modelling multi-terminal DC lines, although this involves substantial additional complexities and yet unproven accuracies). Westinghouse Electric Corporation and General Electric Company have programs available to the industry which have the capability of representing DC lines. There is currently an EPRI-sponsored project to incorporate a DC system model into the Arizona Public Service Company load flow and transient stability programs. Also Commonwealth Edison Company has begun to insert a DC model into their power systems analysis program package. Further information on each of the models is contained in Appendix F of this report.

It would be premature to comment on the satisfaction which industry has experienced to date with these or previous DC transmission models for transient and dynamic system analyses since the models have not yet been widely used or tested. There still seems to be a reasonable amount of caution and skepticism as to the accuracy of the results obtained with each new application.

It seems that future work to be done in this area would involve refining and validating existing models as well as expanding representations to be able to handle multi-terminal DC lines effectively. Much of the urgency for the completion of these research areas is dependent upon the wide acceptance of HVDC transmission as an economically viable transmission alternate to EHV and UHV AC. To date, applications of HVDC in the United States have been limited to isolated, long-line installations in the West and North Central regions.

II-2 Reliability Analysis

Currently system planning in most electric utilities is organized into areas of generation, transmission and distribution planning. Reliability evaluations are performed separately on each of these subsystems in the planning process. Furthermore, reliability evaluation

methodologies for each of the subsystems generally differ in degree of sophistication. Most utilities use probabilistic techniques in determining the reliability of the generation system and use strictly deterministic techniques in analyzing the reliability of transmission and distribution systems.

Only recently have considerable efforts been devoted to applying probability methods to transmission and distribution reliability assessments. Appendix G treats seven available approaches. The first five approaches calculate a local or station reliability index. The PSE&G-Westinghouse Program, the Billinton/Bhavaraju Program and the Power Technologies Incorporated's Contingency Analysis Program (PCAP) are programs currently available for application to real-life systems. The Florida Power Corporation and the Bonneville Power Administration are presently developing programs utilizing high-speed power flow solutions. The remaining two approaches, the TRANSAR method and the Power Technologies Incorporated Multi-Area Generation System Reliability Program calculate area or system-wide reliability measures which provide an indication of overall system adequacy while sacrificing local evaluations inherent in the previous five approaches. Each of these two approaches utilize or expand existing reliability evaluation programs to analyze interconnected load/generation areas.

Generally these methods have not yet been applied widely by industry on large, real-life systems. Hence, it would be premature to attempt to gauge industry acceptance or satisfaction with each of the available models. Where transmission reliability evaluation is being considered, the system planner must weigh the various characteristics (input requirements, calculation techniques and resulting indices) of each approach to determine which approach best suits his requirements, and then proceed carefully recognizing the nature and limitations of the chosen approach, and the meaning of the resulting reliability indices.

Much of what the future holds for increased development and usage of transmission reliability planning tools lies not only in the development of the models themselves but also in essential development in the following areas:

- a. data collection - the development of consistent definitions and procedures for the uniform collection of

transmission system component outage data (and perhaps the establishment of a national outage data bank) for the establishment of complete basic component outage data necessary for reliability studies;

- b. reliability indices - the development of improved reliability indices that will provide a consistent and meaningful (in respect to the customer) quantification of the reliability of generation, transmission, distribution and the composite system;
- c. benefits - the development of a methodology to evaluate reliability benefits that can be used by utilities for determining the reliability criteria suitable for their system and their customers.

Both the U.S. DOE and the EPRI recognize the development of improved quantitative methods for system reliability evaluation as a high priority research item. Each has outlined a proposed conceptual approach to the problem and has scheduled the necessary research within the next few years.

II-3 Institutional Issues

The institutional issues of concern in this report are primarily related to inter-company and inter-pool planning. These problems include the development of coordinated plans considering a consistent reliability basis, the appropriate cost-sharing guidelines and the resultant benefits to each party.

Utility system reinforcements are generally planned on the basis of providing an acceptable level of customer service reliability taking into consideration the characteristics of a utility's service territory. In general, the reliability criteria used by various companies are largely compatible.

Since power system reliability is an issue that has recently been widely discussed, the National Electric Reliability Council (NERC) and other utility organizations have been focusing on this. A uniform guideline on reliability criteria may eventually evolve.

The problems related to the allocation of costs and associated benefits for interconnections and jointly-used transmission facilities are further heightened by the constraints on generation installations regarding increasing

restrictions and remoteness of sites which are considered environmentally acceptable. Furthermore, the planners must also recognize the current emphasis on the need for strengthening interchange capability between power pools and regions to meet various reliability and conservation objectives including regulatory requirements.

To solve such increasingly complex institutional issues, commonly used methods of cost allocation may have to be replaced with new methods to provide a more rational and pragmatic guideline for cost allocation. One such cost allocation concept based on measures of respective uses of the transmission network by various parties and for various functions is described in Appendix H.

III NETWORK-ANALYSIS COMPUTATIONAL TOOLS

A. Digital vs. Hybrid Computers

Network analysis conducted by utilities today primarily relies on high speed, large core, digital computers. Production grade programs for solutions of various complex network problems are made available to other utilities through free exchanges. Typically, with each exchange, improvements have been added to the extent today that most utilities have resident program libraries capable of solving most standard network analysis problems.

However, of wide concern in the industry today is the ability in a short time to assess in detail the more complex network problems, such as transient and dynamic system stability and DC/AC component interactions. The development of hybrid computers has been proposed as an alternate to an all-digital approach to meet such needs. These computers, essentially comprised of a digital machine, to take advantage of the ability for high-speed data-handling and computations, coupled with more sophisticated analog models of certain system components, such as generators and DC ties.

Some such hybrid computers are used in certain areas such as AC/DC system modeling analysis. The University of Missouri has developed a simple hybrid computer for transient stability analysis under the support of EPRI. Currently DOE is supporting Purdue University in the development of a more comprehensive hybrid computer for transient and dynamic stability analysis.

Typically, hybrid computers are of a dedicated special-purpose type and too expensive for a single utility or pool to consider them as a normally-provided planning tool. However, if such a facility is available in a university or research organization, it could be used by many utilities for certain special investigations.

B. Batch Data Input vs. Interactive Graphic System

In the network load flow simulation area, there have been great advances recently in the application of man-machine interactive concepts. Such systems, usually comprised of a remote terminal entry device, a CRT and a phone hookup or direct tie to a main-frame machine located elsewhere, permit more rapid turnaround from initiation of study to final solution.

Although it would appear such an interactive device would have widespread applications, its actual use has been very limited to date because of many restrictions. The CRT size, for projecting a portion of the system set-up for inspection, is typically suitable only for small systems. For larger systems, paging devices are required. Hence, the total system cannot be scanned simultaneously. Additional software is also required to permit the transfer of data from CRT input to main-frame and return. It should be noted that such interactive devices are only used in the system data input area and still require the same solution modules as would in the standard batch data input (typically card image entry) process.

It should also be noted that simple terminal entry without CRT or interactive capabilities can be used to great advantage where large system data is initially batch entered via card and subsequent minor system modifications are entered via terminal. For large data changes the batch mode entry is deemed superior.

In view of these restrictions, it appears that major innovative changes would have to be incorporated in the interactive graphic system before it could be widely used for large network load-flow studies.

IV Recommended R&D Actions

IV-1 Network Analysis

Load Flow -

1. Pursue the application of diakoptics solution to meet increasing sizes of network flow problems.
2. Develop stochastic load flow techniques to be used in the development of transmission plans which account for significant uncertainties while meeting the objectives of minimum cost and acceptable reliability.

Transient Stability

1. Encourage development of more mathematically rigorous techniques in reducing large scale systems to reasonably useful equivalents.
2. Encourage the further refinements in system component representations recognizing the on-going EPRI work in synchronous machine constants.
3. Encourage continuing efforts in the development of appropriate load modeling for transient and dynamic system simulation.

Dynamic Stability

Since dynamic stability problems on large scale networks are of greater concern and could cause more severe impact than in smaller interconnected systems, a greater emphasis should be given to the dynamic stability issue in regional system planning. Therefore the following actions are recommended:

1. Encourage a fuller development and use of eigenvalue analysis in multi-machine system stability investigations.
2. Continue research work, presently funded by EPRI, in development of production-grade mid-term and long-term time-domain dynamic stability

programs, taking into account also the degree of changes in system voltages and frequencies during the long-term simulation to optimize the computation process and improve simulation results.

Static Optimization

1. Pursue further improvements in non-linear programming optimization techniques for power system applications.

DC Simulation

1. Refine and validate the accuracy of existing DC models for transient and dynamic stability studies.
2. Expand such models to be able to handle multi-terminal DC lines effectively.

IV-2 Reliability Analysis

1. Encourage continuing efforts in the research and development of transmission reliability evaluation methodologies currently in progress.

IV-3 Institutional Issues

1. Support NERC efforts in obtaining consistent region-wide reliability criteria.
2. Encourage the utility industry to develop equitable, technically sound, cost allocation guidelines suitable for regional transmission planning applications recognizing such methods already in use.

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SECTION 5.2

REGIONAL TRANSMISSION PLANNING: A STATE OF THE ART ASSESSMENT

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ABSTRACT

The paper describes representative state-of-the-art transmission system planning tools that are relevant to regional transmission system planning. The particular classes of tools considered are those for corridor/route selection, capacity expansion planning, reliability analysis, network analysis, and finally simulation methodology. In the main body of the paper, general comments are made about specific techniques within a given class, including their data requirements; and detailed mathematical descriptions of each technique are provided in the appendices. A concluding section presents areas of possible future DOE research as it applies to regional transmission planning.

I. INTRODUCTION

The purpose of this project is to assess the state-of-the-art in transmission system planning in the context of regional planning. Because of the regional emphasis many of the tools utilized by a given utility for company level planning will not appear in this report. An attempt will be made in every instance to avoid compiling a lengthy document which discusses in detail that which is already obvious to the power engineering community.

The scope of the project is such that only those issues that pertain to the planning of transmission systems on a regional basis will be considered. This focused scope automatically suggests that little if no emphasis will be given to sub-transmission or distribution system planning--these fall well outside the project scope.

The content of the report will be divided into two main parts: The main body and the appendices. In the main body following the introduction a short discussion of transmission system representations in regional energy models will be presented followed an identification and analysis of representative and currently used transmission system models potentially suitable for regional planning, i.e., a few comments will be made about the techniques; their data requirements, and their strengths and weaknesses. In section III recommendations for additional research will be presented. The appendices will be reserved for an analytical description of the existing tools applicable to regional

transmission system planning. Specifically, those tools used for route identification, capacity expansion planning, reliability analysis, network analysis, and simulation methodology will be discussed. Emphasis will be given to input/output information, model details, and restrictive assumptions, if any.

Embarking on a project of this type is formidable at best, since it is quite difficult to even define regional planning in a way that is agreeable to the utility industry at large. Further, whether or not existing methods are applicable to regional transmission planning depends on how regional systems evolve and how such systems are operated. To overcome these rather subjective barriers, a discussion will be presented in subsequent paragraphs describing what indeed will be considered a region for the purpose of this report and what assumptions about transmission planning are most likely to prevail in the period when regional planning will have some impact.

It is assumed that regional transmission systems will follow along the development of what was once called a "superpool" but now seems to be referred to as a region, i.e., a region is a collection of pools where each pool is a collection of areas and each area is a collection of individual units. The importance of this type of hierarchical structure stems from the economies to be realized in dispatching generation as a region rather than on an individual area basis. Within this framework, one might define a transmission region as that collection of pool and area transmission networks which enable interconnected utilities to realize the benefits of regional operation. It is from this vantage point that the work in this report is undertaken.

In order to inject a dimension of realism into the project, a considerable amount of effort was expended in working with the IEEE task force on long range planning to identify the major transmission assumptions considered to be valid over the next 20 years. Of those assumptions identified, the following six are considered germane to this work:

1. "Electrical transmission systems will continue to be a principal means for moving large amounts of energy from one location to another."

2. "The concept of large central station generating plants will continue to be economical and acceptable. This concept may be extended to include concentrations of large plants in close proximity and possible even energy parks."
3. "Power Pools and individual utilities will continue to operate in an interconnected fashion."
4. "EHV and UHV transmission systems will be socially and environmentally acceptable in most parts of the country. Consequently, procurement of rights-of-way through condemnation and certification proceedings will be accomplished in a timely manner."
5. "Contingency analysis will continue to be the primary approach to transmission system reliability analysis and expansion planning, although probabilistic measures of transmission system reliability will receive more attention."
6. "Utilities will continue to negotiate and build interconnections with a minimum of government interference. New interconnections will be constructed only if both parties receive mutual benefits."

Given the above six assumptions and the definition of a regional transmission system it is now somewhat more reasonable to identify the broad questions that regional transmission system planners must answer in planning such systems. Furthermore with a clearer definition of a regional transmission system, the task of evaluating the various regional energy models in terms of their applicability in regional transmission planning will be simplified.

II. IDENTIFICATION AND ANALYSIS OF CURRENTLY USED POWER TRANSMISSION SYSTEM MODELS POTENTIALLY SUITABLE FOR REGIONAL TRANSMISSION SYSTEM PLANNING

Based on the assumption that regional power transmission systems will evolve along lines to support regional operating philosophies, as described in the introduction, the following tools and associated models will be discussed in this section:

- Energy Analysis
- Route Identification
- Capacity Expansion Planning
- Reliability Analysis
- Network Analysis
- Simulation Methodology

A. Regional Energy Analysis

Of the eleven energy models for which adequate documentation could be obtained, none attempted to

include regional transmission models. Although the most interesting of the models investigated (REM by Dr. Marty Baughman at Texas) is not presently capable of including regional transmission considerations, it does have a sufficiently detailed utility structure that meaningful results could be obtained if a transmission submodel were added. So many reports are already available that summarize the various energy models that little need be said further about their individual strengths and weaknesses, and especially since existing models really ignore transmission.

B. Route Identification

Once generation sites and capacities have been established relative to the sites and requirements of the various major load centers, identifying transmission corridors becomes a major undertaking. Not only is this true within areas and pools, but it will also be true within regions, and perhaps even more so. Unlike area corridor identification, regional corridors will cross service areas, regulatory jurisdictions, and, of course, will be financed most likely across individual utilities. Selecting corridors to meet regional energy transportation requirements will no doubt involve analysis tools that are more abstract but broader in scope than those presently used by individual utilities. Even so, existing corridor selection techniques may still be useful in regional planning since they do enable planners to determine the suitability of a given corridor in terms of its physical characteristics, vegetation, wildlife, land-use etc.

Using a suitability index approach coupled with rather simplified computer codes, regions, like areas, can be divided into uniform squares or cells using geological survey maps. Armed with aerial photos, including infrared; geological maps; state and county long-range planning documents, it is possible for planners to derive a data base from which either acetate overlays or computer graphics can be created. Typically, by overlaying the attributes of the various cells a composite corridor map results i.e., those cells less shaded tend to be more suitable for a transmission corridor than the darker cells. Admittedly, the state-of-the-art in corridor selection is crude but the tools do exist which could serve regional planners, at least they can serve as the foundation from which more sophisticated graphical methods can be developed.

Since preceding paragraphs have really only addressed the suitability of corridors from a general use point-of-view, the suitability of a corridor for transmission lines must be furthered evaluated in light of the environmental impact that a specific line would have. The attributes of a geographically suitable corridor when used for a given transmission line must be determined by considering the following line-specific parameters:

- Radio Interference (RI)
- TV Interference (TVI)

Table 1a
IMPACT VARIABLES

1. Total monetary (largely construction) costs to the rate payer 2. Adverse impact on scenic and visual resources 3. Undesirable vegetation change 4. Undesirable change in wildlife communities 5. Undesirable change in aquatic communities	6. Conflict with recreational use potential 7. Conflict with historic sites 8. Conflict with residential use 9. Conflict with agricultural use 10. Conflict with forest land use 11. Conflict with institutional use (schools, etc.) 12. Conflict with industrial use

Table 1b INVENTORY VARIABLES

1. Total depreciated likely construction costs 2. Cell observability 3. Large streams 4. Small streams 5. Lake and ponds 6. Swamps 7. Wooded marsh 8. Submerged marsh 9. National Forest 10. Miscellaneous forest 11. Miscellaneous forest 12. Orchards 13. Agricultural field 14. Residential area 15. Urban area 16. Slope class 5-15 degrees 17. Slope class greater than 15 degrees 18. Registered historic sites 19. Recommended historic sites 20. Proposed historic sites	21. Existing public parks 22. Potential public parks 23. Existing public natural areas 24. Potential public natural areas 25. Existing private non-commercial recreation areas 26. Potential private non-commercial recreation areas 27. Existing commercial recreation 28. Potential commercial recreation 29. Existing scenic easements 30. Potential scenic easements 31. Potential recreation resources 32. Existing major hiking trails 33. Proposed trails 34. Existing boat landings 35. Existing beaches 36. Potential beaches 37. South facing slopes 38. Southwest facing slopes 39. Ridge tops 40. National park 41. Cell observability from roads and historic sites

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- Audible Noise (AN)
 - Electrostatic and Electromagnetic Induction (ES&EM)
 - Row Widths
 - Aesthetics
 - etc.

At the present time, many codes exist which address the general problem of corridor identification and the specific problems of route identification. Since there appears to be a great deal of similarity in the approaches used, only two of the

more representative methods will be discussed further. The two approaches chosen go by the names of "Power" and "Transthetics". Power is a computer system developed at VPI and funded by the Department of the Interior. It was primarily developed to establish the effects that electricity, oil, gas and water, transportation as well as highways have on the wildlife and environmental integrity of a given area. Transthetics, on the other hand, is a computer program that specifically assists electric utilities in locating, buying, and gaining acceptance for the use of transmission line corridors. Power is a general code used to locate various types of corridors and not just transmission line corridors. In its most recent form, the code attempts to optimize corridor location given a

specified origin and destination as well as data quantifying the characteristics of the area being studied. The output from a typical simulation is a description of a corridor in grid coordinates. The coordinates facilitate either drawing the corridor on maps or aerial photographs, or if desired the program has map generation capability on which the corridor can be superimposed.

Some of the special features of Power are that it can consider other factors besides environmental i.e., both sociological and political considerations can be considered as well. Furthermore, the program is quite adaptable to third party testimony in corridor hearings. In light of the move toward three party hearings consisting of the utilities, commissions, and intervenors a tool such as Power could play an essential role in future regional transmission planning.

As is the case with most analysis tools, a number of assumptions are necessary to render the resulting code computationally attractive. The salient assumptions employed in Power are: (1) It is a macrocorridor selection procedure, hence, it cannot pinpoint facilities within a corridor, (2) The origin and destinations between which a corridor is sought must be a priori specified, (3) The program does not deal with Row design, management, or maintenance, (4) Rows are obtainable within the selected corridors, (5) Data are as precise as those now used in making corridor decisions, (6) The compiled economic life expectancy of corridor facilities is 30 years, (7) A value is associated with each major impact category, (8) Environmental laws will remain generally constant, (9) Present knowledge of environmental factors will remain constant, (10) Corridor need is established a priori.

Twelve impact variables are used in Power and they are assigned value weights to reflect the objectives to be met in identifying the optimum corridor. The impact variables are computed from the interaction of some 39 cell parameters. The impact variables as well as the cell parameters are given in Table 1.

The solution procedure used in Power to identify the optimum corridor is to associate with each cell in the study area an index that reflects the impact of a corridor on the sum of the twelve weighted impact variables, where the value assigned each variable depends on the cell characteristic and the corridor. By using the cell impact weights as the cost of moving orthogonally from one cell to another, the least cost path from the starting point to the final corridor destination can be determined using existing network searching algorithms. A distinguishing feature of Power is that for a given optimum corridor the program allows planners to evaluate the cost of a corridor due to temporal changes in the impacts. This facility is implemented by developing curves that presumably represent the most likely average changes to occur in a study area over a period of time. Although the authors of Power do not so indicate, it seems that the temporal considerations may be applicable to deal with the changing social and political

impacts of a corridor built to meet regional transmission needs.

Transthetics was developed by Common Wealth Associates as an aid to transmission planners to gain governmental and public acceptance of transmission lines. The emphasis in Transthetics is to minimize the negative effects and accentuate the positive aspects of routing transmission corridors. The computer code attempts to optimize the selection of transmission lines and their associated corridors.

Compared to Power, Transthetics appears to be narrower in scope but yet much less abstract. For instance, Power does not consider the problems associated with construction management and Transthetics does. On the other hand, Power attempts to address the multi-jurisdictional dimension and Transthetics does not, at least not explicitly. The level of abstractness of Transthetics is best defined by the following eight program modules: Project necessity, corridor delineation, environmental studies, structure evaluation, public disclosure, Row acquisition, line engineering, and finally construction management.

In the corridor delineation phase both acetate overlays and computer graphics are employed in translating quantitative cell data and evaluation into corridor definitions. Factors considered in characterizing cells in the study areas are shown in Table 2.

Using a numerically weighted criteria, an index is defined for each cell to reflect the impacts of a given transmission line on the study area. The larger the impact the darker the cell. This approach provides a relative impact map for each criteria. In fact, criteria can be defined that collectively suggest a strategy and a weighted sum of strategies can become an objective function to be optimized if a route is being sought which is in some sense optimum. Examples of strategies that can be considered are: Minimum damage to natural ecosystems, minimum conflict with existing land use, etc.

Once alternative corridors have been identified which could support a transmission line, Transthetics searches for the one route for which the difference between the estimated TV interference etc., of the line and the desirable levels of RI, TVI, ES&AM levels is a maximum. Of course, this amounts to choosing corridors that skirt around population centers and areas in which line radiation may be objectionable.

In evaluating existing corridor and line routing techniques, it becomes quite apparent that most were developed for use by a specific utility, and hence, questions relating to joint ownership and use are not explicitly considered. In the case of regional networks, these issues become very important as each participating utility must be assured that a given line will enable it to benefit from the regional operation of the pool members. Further, utilities participating in regional activities will be pressed even harder to "prove" that a

Table 2
INVENTORY VARIABLES

PEDOLOGY

- Agricultural Capability
- Existing Erosion
- Erosion Hazard When Using Equipment
- Limitation Of Equipment Use
- Depth To Seasonal High Water Table
- Limitation For Use As A Sewage Deposal Field

TOPOGRAPHY

- Centroid Elevation
- Slope Range Of Soil Type

HYROLOGY

- Intermittent Stream
- Continuous Stream
- Marsh
- Pond
- River
- Lake

VEGETATION

- Deciduous Woodland
- Brush

EXISTING LAND USES

- Agricultural
 - Pasture Vacant
 - Cropland
 - Orchards
 - Out-buildings/barnyard
 - Farmstead
- Residential
 - Rual non-farm
 - Hamlet
 - Mobile home park
 - Vilage
 - Urban suburban
 - Number of units
- Recreation Conservation
 - Golf course
 - Ski area winter sports
 - Play fields
 - Theater stadium park
 - Water related recreation
 - Land related recreation
 - Wildlife forest preserve

Institutional Cultural

- Cemeteries
- Churches
- Schools
- Hospitals
- Historical sites
- Zoos/botanical gardens
- Extractive Industrial
- Industrial Plants Facilities
- Commercial
- Governmental
- Urban/Suburban Vacant

EXISTING TRANSPORTATION/COMMUNICATION

- Roadway Type
 - Trails
 - Township/county roads
 - Unimproved
 - Improved
 - Medium duty
- State Roads
 - Medium duty
 - Heavy duty
- U.S. Highway
 - Divided Highway
 - Interstate Highway
- Other Transportation Communication
 - Pipeline
 - Abandoned railroad
 - Electric transmission line
 - Airports
 - Freeway interchanges
 - Radio TV/microwave towers

PROPOSED LAND USES

- Agricultural
- Residential
- Recreational/Conservation
- Institutional/Cultural
- Industrial
- Commercial
- Governmental

PROPOSED TRANSPORTATION/COMMUNICATION

- Pipeline
- Railroad
- Transmission Line
- Secondary Road
- Primary Road
- Freeway
- Freeway Interchange
- Airport
- Radio TV/Microwave Towers

UNIQUE FEATURES

- Exceptional Visual Quality
- Unique Ecological Area

corridor which crosses its service area but doesn't necessarily tie-in to its system is beneficial when the system is operated as a region.

C. Capacity Expansion Planning

Capacity expansion planning for transmission networks has for the most part been done using one single computational tool: power-flow analysis. Even today it is probably fair to say that few utilities use automated expansion planning tools

to expand their transmission systems. Power flow analysis is used by almost every utility (as shown in a recent DOE survey) because it has proven to be a very effective way to simulate the impact of adding new elements to their systems. In addition, because of the amount of detail that planners can include in existing power flow programs they find that with some experience such techniques can be used with a great deal of confidence.

Upon reviewing the open literature it becomes

apparent that much work has been done in the area of automated network design where capacity expansion planning constitutes the bulk. As early as 1970 Garver developed a method using linear programming to determine where capacity should be added to a network to alleviate overloads. Following this, Fischl introduced a new approach to automated capacity expansion planning which involved the application of Tellegen's theorem. Extending the method proposed by Fischl; Reppen suggested yet another version of automated expansion planning. Most of these methods are deterministic, in that no consideration was given to the random nature of either the system load or the topology of the network. Accounting for the random features of both the network and loads lead to techniques such as that proposed by Baleriaux et. al. or the technique proposed by Henault.

Since it is a foregone conclusion that power-flow analysis can be used in regional transmission planning, and since there are as many workable power-flow codes as there are utilities, no attempt will be made here to present these methods. Rather, the focus in this section will be on those methods that are less known but yet have some applicability to the regional transmission system planning problem.

As mentioned, Garver's approach to transmission system expansion planning appears to have been the genesis of automated capacity expansion planning, and apparently has been used to some extent by the utility industry. The primary function of the method proposed by Garver is to determine the most direct route transmission network to interconnect the generation and load without any circuit overloads. As such the method is deterministic and is based on the application of linear programming to determine the most direct route solution as measured by weights (called guide numbers) associated with each of the reliable routes. Because assigning the weights involves a great deal of judgement, this method is extremely heuristic.

The use of a linear programming algorithm automatically suggest the use of a network model that is quite abstract. Specifically, the only circuit laws complied with by the model used in estimating the most direct transmission network is conservation of flow: at each bus the sum of all flows in and out must sum to zero. In addition, through the use of the concept of guide potentials, the scheme crudely insures that lines are loaded in a fashion that resembles how flow would be distributed through a real system. Viewing the line potentials as simply the difference between the bus voltage angles across the line and the guide numbers as the product of the line reactance and capacity, the procedure used for assigning flows in the lines constituting branches of a network

is quite sound. In fact, in one way or another most transmission expansion planning algorithms based on a linear network model utilize the notion of line potentials.

The computational process that is used by the estimation method involves estimating flows using a linear programming algorithm and then adding a

line to eliminate a particular overload. Repeating this procedure until no overloads exists produces a network which, for the loads and generation assumed, can transport the generation to the load centers without network overloads. An inherent weakness of the method, however, is the lack of a look-back feature i.e., once an addition is made it can never be removed. In some sense, one could argue that the final network is not globally optimum.

The data requirements for the network estimation technique are very modest, consisting primarily of the following:

1. Existing network topology, generation, and loads
2. Proposed new bus locations, generation, and loads
3. Line impedances and capacities
4. Guide numbers

Although the Guide Numbers can be chosen to reflect the planners preference in the choice of available routes, they can also be defined as the line impedance times line capacity and used as described earlier. In a more general vein, the Guide Numbers are line priority weights and, as such, can be defined as the user wishes. In the context of regional transmission planning the guide numbers could be used to reflect subjective constraints such as the environmental degradation associated with a line that must be built in a given corridor. Or the guide numbers could be used to account for perhaps the anticipated political difficulties associated with given routes.

A similar procedure proposed by Kaltenbach et. al. casts the problem more rigidly as an optimization problem. The objective function is the weighted sum of the capacity additions to be considered, and the weighting factors are the unit costs of the capacity additions. The constraints on the linear optimization problem, for a given iteration, are simply that the sum of the maximum angular differences across the busses between which capacity is to be added plus the change in angular difference due to the addition must be less than the smallest limiting angular difference of any line in the branch. As such these constraints are very similar to the conditions used by Garver to determine whether the capacity of a tree branch should be zero or equal to the capacity of the line addition being considered. In Kaltenbach's approach no capacity addition would be made if it resulted in exceeding either the angular difference limit of the capacity being added or the smallest of the limits of the other lines in the branch.

The major drawback of the Kaltenbach procedure is that it cannot distinguish between various line types, yet in real-life the flow in two different line types could be quite different. Furthermore, the incremental capacity additions made using the method are continuous, although discrete changes would certainly be more realistic. This criticism also could be leveled at Garver's approach since

the linear programming solution usually only adds enough capacity to eliminate overloads, but yet line capacities are available only in discrete steps. Finally, neither method seemed to address the problem of loading limits resulting from stability problems. Since the longer the line the less flow it can transmit, because of stability, perhaps additional constraints need to be considered in both instances.

The data requirements associated with the Kaltenbach approach are quite similar to those required by Garver's method except the need for:

1. Unit capacity costs
2. Maximum branch angular difference due to selective outage testing for each branch
3. Lower limiting angular difference of each branch to which capacity is to be added.

In theory there is no reason this approach could not be used for regional transmission planning. However, because of its mathematical formalism, it perhaps would not be as useful as the more heuristic method. Since regional transmission planning will involve as many non-technical issues as technical, a more formalized method may be less appealing to planners.

Lee et. al. have attacked the transmission capacity expansion problem from an integer linear programming point-of-view. Although more theoretically pleasing than the Garver and Kaltenbach methods, for regional transmission planning, integer programming may prove to be too formal. Never-the-less, the fundamental approach taken requires solving three optimization problems: The first optimization problem involves finding the so-called optimal cost-capacity curves for each available corridor. The authors call the method used in finding the optimal cost-capacity curve "M" convolution. Once the curves are known for each corridor then all the new busses are connected to the network using a procedure that determines the optimal connecting line capacities. Starting with the completely connected network a DC power-flow solution is obtained to identify line overloads as well as to calculate the line flow sensitivities to changes in admittances in all corridors. To reduce the dimension of the integer programming problem a screening process is used to avoid considering adding capacity to those corridors which would have little effect on the line overloads. Utilizing a Branch and Bound technique the minimum cost capacity additions are made which eliminate the overloaded lines, but capacity is only added in discrete realizable blocks as defined by the optimal capacity cost curves. Repeated applications of the sensitivity, screening, and integer programming optimization steps produce a network in which sufficient transmission capacity exist to transmit the generation to the load centers without overloading any lines.

The data required by Lee's method is again similar to that required by the other techniques, but because the level of abstraction is somewhat

lower more line specific quantities are needed; quantities such as:

1. Cost-Capacity curves and Row requirements for each line type being considered for a given corridor.
2. Line admittances for all lines and bus real powers for all busses.

Moving away from linear programming ideas, a very promising approach which is quite different is the one proposed by Fischl et. al. In effect, this method optimizes a performance function that can contain both line overloads and costs of capacity additions as a function of the line susceptances. Using Tellegen's Theorem the gradient information needed to update the susceptances associated with viable line additions is obtained by solving the so-called adjoint network equations. The adjoint network differs from the actual network only in that the injections are the gradients of the performance index w.r.t. the line flows associated with the lines to be added. Like all of the optimization procedures, Fischl's method is quite formal, and could most likely not be used to address all of the regional transmission issues at once. However, it could indeed be employed to expand the capacity to eliminate overloads at minimum cost.

Clearly, another problem associated with Fischl's method is that, like the Garver and Kaltenbach approach, the capacities or susceptances are considered to be continuous, thus necessitating rounding-off. An attempt to correct this deficiency has led Fischl to use mixed integer programming ideas. In terms of data requirements only the system susceptances, real power injections, and capacity costs as a function of line susceptances are needed.

D. Reliability Analysis

Evaluating the reliability of a power network is a most formidable undertaking because a network can reside in literally hundreds of different states and each state can affect the systems ability to transmit power in different ways. Some methods, and especially those developed in the pre-computer days, were capable of only determining system reliability in terms of continuity. In the late sixties, however, Billinton, Patton, Ringle, Bhavaraju et. als. developed methods for transmission reliability calculations using a conditional probability approach. Along a similar vein Baleriaux proposed a computationally attractive procedure using graph-theoretic ideas. Pang and Wood extended Baleriaux's work to multi-area reliability analysis which could have a great deal of applicability in regional planning. In more recent times Marks has combined the conditional probability concepts with high speed power-flow analysis to produce a more realistic assessment of a transmission system's ability to insure broad service quality to the customers. In a similar fashion, Masud proposed a method for developing a reliability index through automatic contingency evaluations. Even though a great deal of work has

been done, there does not seem to be one approach that has gained the same stature in the industry as in the case of power-flow analysis. This is certainly true of methods applicable on a regional basis.

The conditional probability approaches in effect determine the probability that an outage of a known or calculable probability results in degraded service quality as the load randomly changes. In most instances degraded or unsatisfactory service is measured in terms of line overloads and/or degradations in system voltages. As stated, it is necessary, in theory at least, to enumerate all the possible system states and their probabilities of occurrence, and for each state evaluate whether for each random load level the system fails to perform as intended. In addition to the probabilities that failures will occur, the work done in the sixties produced two indices, frequency and duration of failures, that have played a role in transmission system reliability analysis. It is quite clear that complete enumeration of all system states is unattractive and especially so if for each state a network analysis is required to determine if the state is a failed state. The literature abounds with in some cases clever variations in the procedure used to obtain enough information without excessive computational resources.

The data required by the earlier versions of the conditional probability approach include:

1. Network topology
2. Element Failure rates λ
3. Element repair times R
4. Criteria of failure i.e., line loadings and acceptable voltage levels
5. Load model

If the repair-failure cycle of system components is ignored, and the load on the system is constant for a given analysis, then the reliability evaluation of a system reduced to contingency analysis. By removing system elements, the impact of an element outage can be determined using any one of a number of variations of the power-flow analysis tools. For contingency analysis, methods ranging from the use of the system Z matrix as proposed by Brown to those based on distribution factors have been used quite successfully in the industry. However, generally, the lack of an index to account for the probability that a given contingency will occur and that the load level can randomly vary due to forecast uncertainty has resulted in use of more probabilistic based approaches as discussed earlier. Since contingency analysis simply involves repeated application of power-flow analysis tools, and since it is, in some sense, a special case of the more general probabilistic methodology little will be said further about deterministic contingency analysis.

Having reviewed the literature quite thoroughly, it suggests that the work by Marks seems to capture the essence of the theoretical notions developed by earlier proponents of the conditional

probability technique. In effect, the approach taken by Marks involves using a fast power-flow coupled with a generator redispatch scheme to assess the impact of all single contingencies on bus service quality, as well as line loading, for various random load levels. For each state considered a search procedure is used to determine the critical load level above which if the load goes a system failure will occur. Using the component failure and repair statistics in addition to a load model described in terms of the transition from critical load levels to non-critical load levels, the standard indices of frequency, duration, probability of failure, in addition to expected unserved energy, expected customer interruptions etc., may be calculated. Of course, for regional analysis the customer related indices perhaps should be identified by pool and area to better reflect the benefits of a proposed regional network, or if less detail is acceptable such indices could be replaced by similar ones but only for boundary busses.

Clearly the data requirements for the Mark's method includes the standard component data in addition to rather detailed bus load data and customer statistics. For most utilities, this type of information is becoming readily available since improvements in gathering feeder related data has been a high priority since the mid-late sixties.

Turning to a more abstract approach, Baleriaux et. al. proposed a procedure for reliability analysis that was based on graph theoretic ideas. Unlike Mark's method, the graph theory technique uses a system model that does not reflect necessarily the proper flow distributions through the network; the only condition that must be satisfied in a typical flow analysis is conservation of flow at a node. Because of this modeling approach, the graph methods cannot include voltage as a measure of reliable service, and, some argue, that it cannot accurately be used to even assess line loading problems. However, what it can do is identify major topological flaws in a given proposed network design as a way of screening alternative plans to eliminate those that, even when all restraints on distribution of flow are removed, are unacceptable. As a first cut regional planning tool such techniques may be very useful, but certainly they cannot and will not replace those methods that model the network in great detail. The indices of reliability that are obtainable from Baleriaux's method are probability of failure, expected demand not served, expected energy not served and the like. In effect this technique requires that a search algorithm, based on the Ford-Fulkerson approach to finding the maximum flow through a network, be implemented to sequentially identify two system states above which there are no failures and below which there are; the states in between are called unclassified states. By repeated application of the search algorithm the set of unclassified states is theoretically exhausted meaning that all the system states have been classified as either acceptable or unacceptable. The success of this basic idea is its clever use of a procedure for decomposing the set of unacceptable states into non-overlapping subsets defined by two limiting states each. Once the

limiting states of the subsets are known it is straight forward to determine the failure probabilities as well as the frequency and duration of encountering a given failure subset.

The data requirements for Baleriaux's technique are quite modest. In addition to the topology and component failure and repair rates only a model of the load is needed. At the present time either a fixed load or a random load can be considered where, of course, random load fluctuations result in heavier computational requirements.

In a relatively recent paper, Pang and Wood extended the graph theory approach to the multi-area problem. Specifically by modeling the random reserve margin capability of each area as well as the failure and repair of area tie-lines, and by using the Ford-Fulkerson algorithm embedded in a search procedure that differs quite substantially from that proposed by Baleriaux, the probability of having insufficient pool capacity coupled with adequate tie-line capability can be determined. In addition the probability of loss-of-load by area can also be obtained. In the original version, at least, Pang and Wood lumped the failures together i.e., as proposed in their paper no distinction was made between tie-line induced failures and reserve margin induced failures. For regional planning, decoupling the failure probabilities into at least these two categories may be useful since in regional transmission planning participants in regional operation most likely will be interested in the effect that a given regional network design has on their reliability. Clearly if a given design improves the reliability of one area in a region substantially more than the other areas, some redistribution of participation in the project would most likely occur.

Since Pang and Wood's technique is basically a graph theoretic approach it suffers from all the same short comings in model detail as does Baleriaux's work. However, the fact that Pang and Wood can model the probabilities associated with the area reserve margin states and are not concerned with area network details, may make their approach more applicable to regional transmission planning. At least, the basic philosophy employed may set the stage for the development of a second generation technique that addresses some of the weaknesses inherent in all graph theoretic methods. The data requirements for the Pang and Wood method includes reserve margin statistics, by area, and tie-line capacities and outage data.

E. Network Analysis

In order to evaluate the overall performance of a given regional network it seems that network equivalencing schemes may become very useful in controlling computer requirements. Further, it is quite reasonable to suggest that before an equitable distribution of responsibility for a regional network can be determined, many area, pool, and regional studies will be performed. Clearly, having a sound equivalencing methodology to use in area studies where only the internal details of a given area are desired would be invaluable to area

planners trying to assess the benefits of a regional network. Similarly, pool level studies may be required to evaluate the effect of a regional network on the interactions between areas in a given pool. In this case, an accurate equivalent of individual areas could greatly simplify such studies. And finally, studies at the regional level most likely will not require area level detail and perhaps not even network details at the pool level. With the above motivation, both static and dynamic equivalencing will be discussed in the subsequent paragraphs of this section.

Unfortunately, equivalencing, in general, has not yet matured to a point where it is routinely used without question. Hence, many of the state-of-the-art statements made in this section with regard to equivalencing must be judged realizing that much testing is required before such methods will be part of a planner's repertoire of analytical tools. Yet, even in spite of the lack of maturity of equivalencing, the concept is sufficiently important to regional planning that its inclusion in this report is warranted.

Static equivalencing schemes being discussed in the open literature seem to, with a few exceptions, be some variation of the original Ward-Hale method. In essence, the Ward-Hale approach simply involves exploiting the block structure of the system admittance matrix to eliminate the components of the voltage vector that describe the voltages at busses in the "external" or "equivalenced" network. The result of the elimination is a set of nodal equations that are reduced in number but which contain after the elimination, the network busses of interest including the boundary busses which connect the "study" system to the equivalenced system. The elimination of busses in a power network is more difficult because the loads are usually nonlinear constant MVA loads, typically the constant loads connected to busses to be eliminated can be converted either into constant current or constant admittances by using the analytical relationship between power, voltage, current, and admittance, as well as the solution results to an appropriate base case power-flow. Obviously, such an approach renders the equivalenced network dependent on the base case results used in creating the equivalent. Studies using an equivalent of part of a network must sacrifice accuracy for a reduction in size and the accuracy gets worse the farther away from the base case the subsequent studies get. After a load is replaced by an injected current or a constant admittance, the standard Ward-Hale reduction scheme can be applied to obtain the analytical description of the reduced network. To perform power-flow studies using the reduced network conversion of the injected currents at the boundary bus back into constant MVA loads is required, again a simple matter given the base case boundary bus voltages.

A new, or relatively so, method for static network equivalencing has recently appeared in various reports as well as the open literature: it is the so-called REI method proposed by P. Dima in Romania. The fundamental idea is to define an REI network which is fed from only one node but which injects

into the busses to be eliminated their specified power injections. Once such a passive linear network has been defined, then all of its internal busses can be eliminated using the more traditional techniques described above. Of course, in addition to being a passive linear network, the REI network must have zero real and reactive power losses and the voltages at the output busses must correspond to the voltages of the busses to be eliminated--thus its no ordinary network. Since the current and power flowing into the network must equal the algebraic sum of the currents and powers injected into the busses to be eliminated anyone of a number of network configuration can be defined to meet these requirements, and then reduced.

In general, since a reduced network is a function of the data base used to create the equivalent, studies deviating from the base case are subject to some inaccuracies, some tolerable and some not. Furthermore, since network reduction has a tendency to destroy sparsity, the benefits to be realized from equivalencing part of a network can be either small or non-existent--this is an important consideration. Other weaknesses associated with state-of-the-art reduction techniques are that often the reduced network equations converges to solutions that are physically unacceptable, and finally solution accuracy is unacceptable. Tinney suggests that the source of many of these difficulties stems from the way in which voltage controlled busses are considered; retaining too many such busses defeats the purpose of equivalencing and retaining too few aggravates the problems. Other failings of existing methods are that individual element identities are lost in the equivalenced portion of the network, thus making it impossible to determine whether changes in the study portion of the network create problems in the equivalenced network. Based on the work done by SCI in the area of dynamic equivalents, it was found that for the WSCC system the REI method broke into numerical instability but that the current sink approach, where loads are presented in terms of injected currents, network reduction was effected quite successfully. Although, it would be premature to propose that the REI concept should be discarded, future work is in order to better grasp the attributes of this potentially viable approach to network reduction.

In addition to studying the steady state performance of regional transmission networks to identify the best plan i.e., the one that performs adequately for all areas represented, perhaps even more stringent study requirements will involve dynamic analysis. Configuring systems such that disturbances do not propagate from the area level upward will be an important system planning function. For the same reasons given w.r.t. steady state analysis, dynamic equivalencing may become a vital part of regional dynamic analysis. Because of the complexity of dynamic analysis very few comprehensive research activities which have carried the issue from theory to testing exists. Representative of the work done, however, is an EPRI project undertaken by Podmore et. al. of SCI. It is this report from which much of the remaining discussion has been extracted. Developing a dynamic equivalent of, for example, an area of a

region, involves 1) identifying coherent groups, 2) eliminating both load and generator busses using static equivalencing schemes as described earlier, and 3) aggregating the dynamics of those units in a coherent group. Many attempts have been made to devise a reliable method for identifying coherent groups; ranging from eigenvalue analysis to simulation. Podmore chose to develop a simplified, and hence, fast, simulative procedure for identifying coherent groups for a variety of different types of disturbances. For the most part this approach has worked, although re-identification of the groups is necessary as the type of disturbance changes. The validation of the method was successfully accomplished utilizing several actual systems.

The simulation approach to defining coherent groups for a given disturbance type as proposed by Podmore involves first developing very simplified dynamical and network equations that describe the changes in machine angles due to disturbances such as a fault, loss of generation etc. As such, the equations used constitute a linear set of equations which can be solved very quickly, and especially since all disturbances are transformed into either changes in the accelerating power of a machine or changes in the load injections at load busses, or changes in load injections at generator busses. Comparisons of the changes in power angle as calculated using first the linearized analysis and then the full transient stability analysis reveal that with reasonable accuracy the simplified model can be used to identify the coherent groups.

Once coherent groups are properly identified, then the next step is to reduce all the generators in a given coherent group outside the study area or pool down to one equivalent unit. At the same time, load busses outside the study area are replaced by an equivalent using techniques described earlier. To reduce the generator busses two constraints are enforced: The injected power into the boundary busses are conserved and the flow out of each coherent group into the boundary busses is conserved. Applying straight-forward reduction techniques under the above two constraints results in coherent groups being reduced to one bus which is connected to the boundary busses through phase shifting transformers. Based on the Podmore work all elements of the equivalent generator bus exhibit characteristics that do not appear to create simulation problems.

The remaining problem is that of aggregating the dynamic characteristics of all units in a coherent group in such a way that the equivalent unit formed in the aggregation process exhibits the same speed, voltage, and total electrical and mechanical power changes as the coherent group of individual units do as a result of a given disturbance. Fundamental to the aggregation technique employed by Podmore is the assumption that "the linear and nonlinear characteristics of the equivalent models can be identified separately." The linear equivalent of all the linear characteristics of the units in a given coherent group is determined by first defining a linear model structure and then adjusting the model parameters so that the squares of the magnitudes of the relative differ-

ences between the model transfer function and the actual aggregated transfer functions is a minimum for specified discrete frequencies. Through the application of the initial and final value theorems to the transfer functions of the units within a given coherent group, the nonlinear characteristics of the equivalents are determined. By comparing the frequency responses of the equivalent models against the actual aggregated model responses for the various generation unit subsystems the agreement was found to be quite good for the like units. However, aggregation of essentially different unit types produces unsatisfactory equivalents, thus before aggregation is attempted like units must be identified within a coherent group and an equivalent model developed for each of the types.

Through extensive testing using the 39 bus, 10 generator New England System; the 1027 bus, 295 generator Eastern U.S. System, the 1308 bus, WSCC System, the concepts proposed for coherencing identification, network reduction, and finally machine aggregation have been shown to be effective. Comparison of results using coherency-based dynamic equivalents with full scale transient stability analysis reveals dynamic equivalencing is quite accurate, and hence, represents a viable alternative to the more traditional transient stability analysis. For regional transmission planning the use of dynamic equivalencing to reduce those pools and/or areas not of specific interest in a particular study may become the only feasible way dynamic studies can be performed on a regional basis. Furthermore, the data requirements for coherency-based dynamic equivalencing are no different than for transient stability analysis--this was a constraint Podmore placed on the methodology developed, and as such is a major advantage of the proposed technique.

F. Simulation Methodology

This section will be devoted to a discussion of available methods for solving general design problems. Because of the special problems to be addressed by regional transmission planners, it is particularly important to include this discussion in the report. The motivation for this section is simply that regional transmission planners representing individual areas most likely will be faced with establishing a design methodology and formulating a design philosophy that will facilitate determining trade-offs of various expansion plans with emphasis on trade-offs between individual participating areas. Fortunately, much of the material to be presented which describes various mathematical formulations is available in well written papers referenced at the end of this paper.

To adequately describe the applicable principles and ideas behind state-of-the-art approaches to system design, every effort is made to include techniques which recognize the uncertainty associated with both system models and associated data. In this context then the transmission system design/planning problem can be formulated as an equality and inequality constrained optimization problem where the cost function to be minimized is

the sum of various area level costs functions which themselves contain a cost component of uncertain value--to reflect the real-world problem of being unable to predict future conditions perfectly well. The equality and inequality constraints represent functional conditions placed on both the dependent and independent variables, where the independent variable represents expansion decisions needed such as line additions. The dependent variable defines the state of system components such as generating units or lines. Further, each functional constraint includes a random variable to take into account the uncertainty of system parameters such as demand. For real-life planning problems the above formulation exhibits the following characteristics

1. The independent and dependent variable are discrete.
2. Both the cost functions and parameter values are random.
3. The dimensionality of the problem is high.

If the formulation is to be dynamic, then in addition to the above relationships there must exist a difference relation between the present independent and dependent variables and the dependent variable in the next time increment. Dynamic formulations by necessity require a reduction in the number of dependent variables and static formulations require assuming that the dependent variable in one time period is equal to the dependent variable in all preceding periods being considered i.e., the dependent variable does not change value over subsequent time steps.

The two extreme design problems that can be extracted from the above generalized formulations is the nominal design and the tolerance design. In the case of a nominal design the planner assumes that no uncertainty is associated with either the cost functionals or the functional relationships between the dependent and independent variables. This particular formulation is the one most frequently used in state-of-the-art design as discussed in previous sections. Tolerance design is really design under uncertainty where it is desired to obtain the range of the variations in the dependent variable for known uncertainty in both the cost functionals and the dependent and independent variable functional relationships. An example of this type of design/analysis formulation is the stochastic power-flow problem; The cost functions are the squares of the power mismatches at each bus, the independent variables are the generator powers etc., and the dependent variables are the load bus voltages. With uncertainty in the system loads it is desired to determine the range of the variations in the system bus voltages. The standard power-flow problem is an example of a nominal design formulation.

System design under uncertainty suggest two distinctly different problem formulations. Fischl calls these a) Worst Case Design and b) Statistical Design. In the former case, the planner/designer

specifies the maximum and minimum range of the cost functionals and functional relationships and seeks both the nominal values of the dependent variable as well as its maximum deviation from the nominal. For instance, in the stochastic power-flow problem, one would specify the maximum and minimum value of load fluctuations and the worst case analysis seeks not only the minimum mismatch voltage profile but also the amount of voltage support required to insure zero mismatch. Statistical design on the other hand involves describing the problem uncertainties more completely using probability distributions and seeks to obtain the mean value and the allowable range in the design parameters.

Because planning under uncertainty is by far the most realistic assessment of the environment in which regional transmission planners will perform their tasks, a brief discussion of the state-of-the-art methods for design including uncertainty will be presented below. In every case, the specific techniques considered are derivable from the general formulations discussed where in most instances the structure of the cost functions and the functional relationships between the dependent and independent variables dictate the mechanics of the specific techniques.

Linear Programming Under Uncertainty: Simply stated, the LP problem with uncertainty is one in which given the uncertainties in the functional relationships between the dependent and independent variables it is desired to determine the value and maximum deviation of the dependent variable required to optimize the cost function to solve this problem. Three approaches can be used: LP Sensitivity Analysis 2) Probabilistic Programming, and 3) Flexible Programming. The most interesting of the three in terms of regional planning is the latter, where it is desired to determine the optimum value of the independent variable and its maximum deviation which will optimize the cost of changes in the optimal design/plan, if uncertainties in the functional relations are known without detailed knowledge of their statistical properties. Although presently limited to linear formulations the use of the concept of flexible design/planning seems quite appropriate for regional transmission planning. As Fischl points out there has been little done in solving flexible design type problems and what has been done involves embedding the problem in a larger deterministic LP problem.

Non-linear Programming: In general, the non-linear programming problem involves optimizing a non-linear cost function subject to non-linear functional relationships between the dependent and independent variables. When uncertainty is included in the problem, it is often referred to as Tolerance assignment since such problems can be viewed as a problem of flexible nonlinear programming under uncertainty. In such cases one is interested in determining the independent variable and its largest deviation which optimize a cost function subject to uncertain functional relationships between the dependent and independent quantities. As in linear programming there are

distinct versions of tolerance assignment: 1) the worst case design and 2) the statistical design. As before, the difference is simply in the statistical data required to describe the uncertainty. In the former case, one attempts to minimize the cost expressed in terms of the maximum and minimum tolerances on the independent variable subject to constraints on performance specifications as described using inequality functional relationships between the dependent and independent variables. Of course, in the latter case, the problem becomes one of determining the maximum deviation of the independent variable which minimizes cost subject to the condition that such deviations will result in the satisfaction of the design specifications with a given probability.

As in the case of the LP problem under uncertainty, the existence of statistical tolerancing techniques, at least conceptually, could suggest planning tools for regional transmission planning that more effectively deal with the many uncertainties sure to be encountered by regional planners. The ability to include uncertainty into the description of the equations describing the interrelationship between areas/pools will most likely become very useful in assessing the benefits of regional transmission systems.

Multi-level Optimization: Of all the design/planning methodologies currently available, the multi-level optimization technique addresses more directly the planners problem of formulating and solving large scale system design problems. Typically transmission planners must design systems which optimize many different things such as cost, land use, reliability etc., and as these quantities are invariably coupled through a set of very large scale system relationships.

The fundamental notion behind multi-level optimization involves the decomposition of the planning problem into sub-problems such that each sub-problem can be solved in a way that facilitates determining the overall optimal solution to the larger planning problem. For instance, if one were to couch the power-flow analysis problem in a multi-level context then the optimal design for minimizing overloads and the optimal design for minimizing voltage degradations could be determined separately and combined to achieve the desired planning result.

Clearly, decomposition of a system can be done on a structural, priority of action, or temporal basis depending on the problem being addressed. In general system decomposition is effected by introducing new variables into the system which are iteratively updated as the search for the optimum solution occurs. The up-dating or coordination is necessary to resolve interactions and conflicts between the subsystems and to insure that overall system objectives are met.

The literature describes several methods for dealing with large-scale modeling and optimization problems in a multi-level sense, and common to all of the techniques is the ability to 1) achieve an additively separable structure of the overall

system design problem 2) define subsystem problems that can be independently solved and 3) achieve an overall system optimum design through coordination of the subsystem optimization problems. Fundamental to the application of a multi-level approach to system design is system decomposition and subsequent coordination between the subsystems and the overall objective to be achieved. Fischl states that at present there are three principles being discussed as possible candidates for performing the coordination task: 1) the balance coordination principle, 2) the prediction coordination principle, and 3) the penalty coordination principle. The difference between the three approaches is how the coordination between the sub-systems and the system objective takes place, but at this stage further detailed discussions is perhaps not warranted as this is an area of current research.

Vector-Optimization: Because many planning tasks, and certainly regional transmission planning tasks, require seeking solutions that are in some sense obtained through compromise, vector optimization concepts could potentially be invaluable in identifying the best expansion plan. It is not difficult to envision the inevitable difficulties that will arise when area and pool transmission planners attempt to configure a regional network that not only facilitates regional operation but also enhances the transmission capability of their own individual systems -- which is clearly a vector optimization problem. Another very likely scenario is that in which trade-offs between the various objectives, ranging from technical to political, must be quantified as a rational basis for decision making. Within the general area of vector optimization, trade-off analysis becomes and explicit by-product of the procedure.

Vector optimization theory cannot be classified as new since much of the state-of-the-art was implied by Kuhn and Tucker in 1951, and by Koopmans in 1951. Having remained basically undeveloped until the sixties, public investment problems led to its relatively fast maturation. However, it is important to note that much work remains to overcome the computational barriers normally found in costing and solving multi-objective function type problems.

To classify vector optimization solution techniques it is convenient to resort to the chronological order in which the techniques were developed, which is given below:

1. Generating Techniques
2. "A Priori" Articulation of Preferences
3. Progressive Articulation of Preferences

The generating techniques all have in common the ability to generate the complete set of noninferior solutions and associated objective function values. In general, such techniques provide all the information one can obtain from the problem i.e., the noninferior solutions are obtained, the values of the associated objectives are obtained, and finally the trade-offs between the various solutions are

explicitly obtained. As one might expect, the major weakness of most generating techniques is computational efficiency when several objectives are involved. Although there are four or five identifiable generating methods, the two conceptually simplest methods are the weighting method and the constraint method, both implied in the work by Kuhn and Tucker. The weighting method simply involves solving a scalar optimization problem for a large number of different weighted sums of the objectives. Thus, solving a single vector optimization problem is in some sense equivalent to solving a series of scalar optimization problems with variable weights. The appeal of this approach is simply that computer programs readily exist which can solve scalar optimization problems and especially if the objectives are linear functions of the decision variables. The constraint method evolved from the realization that the necessary condition equation for the optimum of a sum of weighted objectives could be rewritten so that all of the objectives except one appear as constraints and not as objectives. By parametrically varying the lower bound on each of the constraints it is possible to generate the set of noninferior solutions and associated objective function values. Again, such a method is attractive because it transforms the vector optimization problem into a scalar optimization problem for which many solution codes exist.

Of the articulation of preference methods, the most interesting for the purpose of this work is the "surrogate worth trade-off (SWTO) method, where some of the other methods are: goal programming, assessing utility functions, and elective method. The SWTO technique generates trade-off functions which show the relationship between a weight on one objective relative to the weight on another objective as a function of the first objective. From these functions a planner can readily assess the relative benefits of further improvements in a given objective relative to another. A characteristic of the SWTO method is that it is believed to provide a great deal more information than the optimal weight or utility function methods, although less than the maximum information obtainable from the generating methods discussed earlier.

III. AREAS OF FUTURE RESEARCH

The emphasis in this section will be to identify potential research problems which could best be addressed by DOE. To insure continuity between this, an important part of the report, and the previous discussions the same topic sequence will be used.

A. Regional Energy Analysis

Clearly because very few if any of the better known "Energy Models" contain detailed representations of transmission grids, there is much work to be done before a workable model could be made available. The main focus of research in this area should be the development of energy models that have a regional structure, consider the uncertainties of planning, and that retain the effect of regional transmission constraints on energy flow. It is very possible that such effort should even

approach the modeling issue from a new perspective. Present models are based on a Leibnizian philosophy of rationalism in which models are based on first principles. Alternative modeling approaches are those of an empirical nature based on a Lockean philosophy and require the use of measured data to establish model details. The developers of a fairly well known agricultural model found the use of both first principles and empirical data quite beneficial in developing policy analysis codes for that industry. The combination of Leibnizian and Lockean modeling philosophies results in a Kantian approach which perhaps should be the basis for future DOE funding on energy models.

In addition to the above, a great deal of research could be directed to the basic problem associated with model decomposition. Any tools developed for regional analysis that are to be computational attractive must be decomposable into generalized submodels which themselves can be assembled to study a particular aspect of the regional energy problem, including regional transmission planning.

B. Route Identification

Determining acceptable routes for regional transmission systems will be a major undertaking in any regional planning activity. Although several codes do exist which allow one to identify routes which minimize in some sense the impact of a given line on the environment, none appear to be sufficiently developed to quantify the benefits and trade offs associated with a given line route. Since the primary purpose of regionalization is to take advantage of diversity, to share reserves, etc., it is imperative that codes be developed that can translate the technical details in to costs and benefits of a given route. As in the last several years, the availability of routes will be determined more by citizen's groups and less by the utilities themselves. In short, extensive development work is needed to ascertain how the routing problem can be cast as a vector optimization problem with the trade off between the various objectives properly determined.

C. Capacity Expansion Planning

Since the industry is basically relying on power-flow analysis to plan transmission expansions, little true DOE funded research is needed to further the state-of-the-art. However, if one agrees that automated methods would be valuable to the industry then a great deal of work remains to be done to provide workable tools. Of particular importance would be the development of automated capacity expansion techniques that inherently consider the uncertainties associated with demand forecasts and construction times. In addition, there is perhaps much to be gained by pursuing further the development of dynamic equivalencing methods, as well as equivalencing in general, which will reduce the computational burden of performing dynamic simulation studies. In the context of regional planning, both steady-state and dynamic analysis will require a better understanding of the analytic properties of power systems.

D. Reliability Analysis

Transmission system or composite system reliability analysis is an area receiving much renewed attention in the power community. The focus appears to be on the development of both a better understanding of reliability as it impacts on overall system costs and worth as well as on the development of tools that more fully embrace customer perceptions of service quality. The fundamental issue to be addressed by any reliability research is simply how can utilities continue to provide reliable service as perceived by the various customer types and still satisfy increasingly more stringent financial constraints. To properly address this issue a better understanding of reliability measures and how such measure relate system design to service quality is essential. At present, DOE is funding research which to some extent is focusing on these fundamental problems. This work clearly should be the basis of future DOE research on reliability.

For a more detailed description of the reliability R&D needs the reader is referred to a recent workshop proceedings EPRI WS-77-60, 1978. These proceedings contain a collection of papers which describe both reliability research needs as well as priorities.

E. Network Analysis

The thrust of research in the network analysis area should be to better understand the relationship between the network parameters and properties of the network, both in a steady-state and dynamic sense. Because of the degree of uncertainty associated with planning any network the size of a power network, all network research effort should be as general as possible.

Topics of particular importance to regional network analysis are decomposition, equivalencing, coherency, and aggregation. Although many of these areas are currently being researched, it is fair to say that a great deal more research is needed before such concepts will be useful to the practicing engineers. For regional transmission planning where there may exist a natural topological decoupling between the areas, many of the notions referred to above could play a vital role in exposing the performance characteristics of the various alternative plans.

F. Simulation Methodology

The overall system design problem is quite complex since it usually involves optimizing a collection of very different objectives. As discussed in the preceding section, there are many shortcomings associated with present solution techniques for multi-level and vector optimization problems which also include uncertainty in system models and input data. Since regional transmission design most likely will require a formulation with either a multi-level and/or multi-objective flavor, DOE funded research in this area would be very appropriate. In addition, consideration must be given not only to the analytical tools

to be used in modeling and designing systems, but also to the environment in which these tools can be most successfully used. Regional planning will involve many personalities, all with slightly different interests and concerns, and all with a different philosophy of system design. In fact, it could turn out that analytical techniques must be developed with the planning hierarchy a priori defined.

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STATE OF THE ART ASSESSMENT OF PLANNING TOOLS FOR LARGE SCALE TRANSMISSION SYSTEMS

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1.0 ABSTRACT

The state of the art of computational tools for large-scale transmission system planning is discussed and recommendations for future research are presented. Deterministic tools such as load flow and dynamic simulation are treated first, followed by approaches to reliability analysis and automated transmission system expansion. Tools or techniques of particular interest are summarized in more detail in 12 appendices.

2.0 INTRODUCTION

The transmission system planning problem consists of determining the location, kind and timing of facility additions that will meet the predicted load demand for a period of several years in the future. The planning objective is to minimize investment and operating costs within constraints imposed by reliability, environmental, legal and political considerations. Due to the large number of constraints and the diversity of techno/economic considerations it would be fruitless to attempt to solve this problem in its entirety by a single computer model. Also many of the constraints are difficult to quantify and incorporate in mathematical planning models. Therefore, the present and foreseeable role of such models in transmission planning is to act as tools that the planner can use in evaluating specific subproblems.

The ingredients of a study procedure for transmission planning and design are indicated in Figure 2-1. Task I, "Identify basic alternatives" has been labeled "planning" and the remaining tasks "design". Although this division may be somewhat arbitrary it will serve as a point of reference for the transmission planning problem as addressed in this paper. Furthermore, it emphasizes that the output of the planning process is not one optimum solution, but rather a range of possible good alternatives. These alternatives need to be engineered to the point where precise techno/economic comparisons can be made and final decisions drawn based on these comparisons as well as on non-technical and non-economic considerations.

	PLANNING	DESIGN		
	I IDENTIFY BASIC ALTERNATIVES	II ENGINEER ALTERNATIVES TO FUNCTIONAL EQUIVALENCY	III SELECT PRIME ALTERNATE	IV ENGINEERING OPTIMIZATION OF PRIME ALTERNATIVES
PERFORMANCE CRITERIA - SYSTEM				
LOAD FLOW STUDIES				
DYNAMIC STUDIES - STABILITY				
DYNAMIC STUDIES - LOAD REJECTION				
SWITCHING OVERVOLTAGE STUDIES				
SPECIAL TRANSIENT PROBLEMS				
SUBSTATION CONFIGURATION RELIABILITY ASSESSMENT				
ECONOMIC COMPARISON				
SHORT-CIRCUIT STUDIES				
TRANSMISSION APPARATUS SPECIFICATIONS				
PROTECTIVE RELAY SPECIFICATIONS				

FIGURE 2-1

TASK ORGANIZATION FOR TODAY'S TRANSMISSION PLANNING AND DESIGN STUDIES

The planning process as defined encompasses the following activities from Figure 2-1:

- o Determination of constraints including performance criteria that the system must meet.
- o Load Flow Studies including the selection and steady state testing of expansion options.
- o Dynamic studies.
- o Reliability assessment including sub-station configuration effects.
- o Economic comparisons.

This list reflects the way transmission planning is performed today and it implies one

very important characteristic: All mathematical tools used are analytic; that is, they analyze the performance of a system preselected by the planner who then compares the computed results with desired performance criteria. In other words, system synthesis is performed by the planner himself and not by his mathematical models.

Over the last decade, several computational tools to synthesize systems have been proposed and some have seen limited use. One of the objectives of this paper is to consider the future of these models and to judge to what extent automatic synthesizing may be useful to the planner. Recently, the concept of automatic synthesizing has encountered a formidable competitor referred to as "interactive computing" [1]. The thesis of interactive computing is that both superbly programmed computers as well as highly trained human brains have their inherent limitations in producing good system expansion plans, but that their capabilities are highly complementary: The computational tools can handle the most massive analytical tasks while the human brain can provide the associative capabilities and considerations of a wide range of both quantitative and qualitative factors that are essential for the synthesis task. To promote such synergism, computer programs are made interactive providing easy, rapid and meaningful communication between the computational tool and the user. At present it appears that much more success in the planning process is experienced via the interactive route than via attempts to automate planning tools. However, the two are not incompatible, as the addition of synthesis capabilities to the interactive tools could potentially increase their utility.

Separation of Generation and Transmission Planning

Traditionally, owing both to the capital and lead time requirements, generation capacity and site planning have preceded and have provided the terms of reference for transmission planning. The design and siting of transmission facilities have generally been secondary steps in planning, following both the selection of power plant sites on the one hand and location of load area substations on the other. In the U.S., transmission represents approximately 12 % of the total utility plant cost while the corresponding figure for generation is about 63 %. It is only natural, therefore, that the selection of economic plant sites and location of load center substations should take precedence over the transmission facilities which interconnect them.

Today there are several influences which cause a shifting emphasis in system planning. Such influences as changing fuel prices, uncertainty in future fuel supplies, regulatory constraints, and financial constraints are having a profound effect. Most evident are delays in capacity additions and greater dependence upon transmission to share reserves. The less evident effects are the merging of generation and transmission planning considerations to respond to the requirements for environmentally sensitive plans.

The result has stimulated the need for generation and transmission trade-off studies. However, for the purpose of this paper the transmission planning problem definition presupposes fixed generation expansion plans.

Transmission Planning Problem Definition:

The planning problem addressed in this paper may be stated as follows:

Given:

1. The existing transmission system and committed facility additions.
2. Load prediction for load center substations for the transmission planning period, typically 5-20 years.
3. Generation expansion plan and generation operating cost characteristics.
4. Transmission ROW and substation site alternatives and restrictions.
5. Technical and economic data on transmission facility options.
6. System performance criteria.

Determine:

The most economic transmission expansion plans that will perform satisfactorily throughout the planning period when subject to the predicted load. Satisfactory performance refers to both performance criteria and the observance of constraints and restrictions of a technical, environmental, political or financial nature.

The expansion plans will be specified in terms of:

1. System Configuration - Location and connection of facilities.
2. Characteristics of New Series and Shunt Facilities.
 - o AC or dc
 - o Voltage Level
 - o Current Rating
 - o Type classification sufficient to establish cost and reliability to precision required for economic analysis and system performance analysis.

This definition, while it will serve for the purpose of this paper, is somewhat narrow. It does not, for example, consider flexibility requirements which may be imposed to assure that the expansion plan can be adjusted in a reasonably economic manner in the face of alterations in load

forecast, commissioning of generation, etc. Traditionally such flexibility is assured by performing alternate scenario studies.

Wish List of Model Capabilities

In general terms we are realistically looking for computational tools that can:

- A. Determine steady state voltages and loading for a specified system and state.
- B. Determine stability margin for a specified system, state and disturbance.
- C. Evaluate system reliability reflecting the risk of unserved demand both due to adequacy and security considerations.
- D. Determine least cost expansion plans based on deterministic and probabilistic performance criteria.

Tools covering the two first categories will be discussed in Section 3 while those responding to categories C and D will be discussed in Sections 4 and 5 respectively.

2.1 Notation

The following notation is used throughout this paper except where noted:

$P_k + jQ_k$ = complex power injection into bus k.

$Y_{km} = G_{km} + jB_{km}$ = complex elements of the bus admittance matrix.

$Z_{km} = R_{km} + jX_{km}$ = complex elements of the bus impedance matrix.

V_k = voltage magnitude at bus k.

θ_k = voltage phase angle at bus k.

$E_k = V_k \angle \theta_k$

I_k = complex current injected into bus k.

Matrices are indicated by brackets, e.g., [Y].

Column vectors are underlined, e.g., $\underline{I}$.

Row vectors are indicated as transposed column vectors, e.g., $\underline{I}^T$.

3.0 DETERMINISTIC SIMULATION AND TESTING

Because of the complexity and size of the mathematical representation of all but very small power systems, accurate solutions are only available by the means of computers. Although various

analog computers are still used in some special areas of power system analysis, the digital computer is usually the best and frequently the only computation tool available to the system planner. The digital computer load flow program, used for deterministic steady state analysis, is the work horse of the planning engineer. The characteristics and methods for such analysis are described in Section 3.1 and in Appendix 1.

Second on most planners' list of computer tools is the stability program capable of simulating the dynamic response of the system to a specific disturbance. While steady state analysis is a must for any planning effort, the analysis of dynamic behavior at the planning stage may not be of critical importance in stiff systems where the correction of possible dynamic problems does not normally involve the alterations of system configuration. However, in systems where stability is of special concern, the bulk of computer and manpower resources available for the planning function may well be applied to dynamic analysis.

A third deterministic tool, the short circuit program, is important for planning some high load density systems, but is for most systems used primarily in the design phase. Such programs are not discussed in this report.

3.1 Steady State Network Analysis

Analyses of steady state network conditions are most frequently performed using a load flow (or power flow) program. In many cases the load flow program would be the only analytical procedure used in transmission steady state planning.

Load flow programs can be categorized as dc load flows and ac load flows. The dc load flow provides an approximate solution of the real power-phase angle relationship based on a network model consisting of reactances only. The dc load flow and its limitations will be discussed in more detail in Section 4.

The ac load flow solves the full complex network equations and is by many taken as the ultimate word in detailed and realistic representation of the steady state of a power system. However, as with most mathematical models the ac load flow program contains simplifications and arbitrary choices in modeling that may be of significance in certain cases and should be considered by the transmission planner in analyzing the results.

Formulation of the Load Flow Problem

Load flow solutions provide bus voltages and power flow in the transmission system for specified generation and load conditions. This information is needed to test the system's ability to transfer energy from generation to load without overloading particular lines and to test the adequacy of voltage regulation by shunt capacitors, shunt reactors, tap changing transformers and the var supplying capability of rotating machinery.

Solution methods based on both the bus admittance matrix (Y-bus) and the bus impedance matrix (Z-bus) network representations are used.

FIGURE 3-1

SYSTEM QUANTITIES

If the bus currents $\underline{I}$ shown in the 3-bus system in Figure 3-1 are known, the bus voltages $\underline{E}$ can be obtained by:

$$\underline{E} = [\underline{Z}] \underline{I} \quad (3.1)$$

where $[\underline{Z}]$ is the bus impedance matrix. Conversely if the bus voltages are known the bus currents are obtained by:

$$\underline{I} = [\underline{Y}] \underline{E} \quad (3.2)$$

where $[\underline{Y}]$ is the bus admittance matrix. Both (3.1) and (3.2) are linear equations of complex variables. If in equation (3.1) the currents are specified, the solution $\underline{E}$ is arrived at directly by matrix multiplication. If a mixture of currents and voltages were specified, the unknown currents and voltages could be evaluated by a variety of mathematical techniques for solving sets of simultaneous linear equations.

Because of the physical characteristics of generation and load, the electrical conditions at each bus are described in terms of active and reactive power rather than by bus current. In a load flow study, therefore, the electrical conditions at a bus are described by four quantities.

P - Active power into the transmission network

Q - Reactive power into the transmission network

V - Magnitude of bus voltage (voltage to ground)

θ - Angle of bus voltage referred to a common reference

The bus current is related to these quantities as follows:

$$\underline{I} = \frac{P - jQ}{V} e^{+j\theta} \quad (3.3)$$

In order to define the load flow problem to be solved, it is necessary to specify P and V for generator buses because these quantities are controllable through governor and excitation controls, respectively. For the loads, one generally specifies the real power demand P and the reactive power Q. Since there are losses in the transmission system and these losses are not known before the load flow solution is obtained, one bus must be retained where P and Q are not specified. At this bus, called a swing bus (sometimes "slack bus"), V as well as θ is specified. Since the voltage quantities are specified (that is, held constant during the load flow solution), they are the reference voltage quantities for the system. Table 3-1 summarizes the standard electrical specifications for the three bus types. The classifications "generator bus" and "load bus" should not be taken literally. There may, for example, be occasions where a pure load bus will be specified by P and V.

TABLE 3-1

Bus Type	SPECIFIED QUANTITIES			
	P	Q	V	θ
"Generator" (PV-bus)	X		X	
"Load" (PQ-bus)	X	X		
Swing bus			X	X

The objective of the load flow solution is to determine the two quantities at each bus that are not specified. The specification of P and Q rather than I transfers a linear network problem to a non-linear problem which requires iterative solution procedures. Bus specification is the tool with which the engineer manipulates the load flow solution to obtain the desired information.

The preceding bus specifications may be classified as local and unconditional. An example of local conditional bus specifications is the specification of a constant P and V for a generator but with the V specification only being in effect as long as specified var limits are not violated. Such unconditional specifications may

cause computational problems since they are transforming an otherwise continuous problem into a discontinuous problem. In certain limited cases remote specifications may be used. For example, one may specify the power and voltage at a bus and then specify a remote bus which will adjust the active power supply to keep the specified voltage constant. This specification may simulate a remote control scheme used in some systems, or it may be used as an artifice to obtain specific design information.

Inherent Assumptions

The problem formulation stated has been universally accepted. It nevertheless contains certain limitations and idiosyncrasies that should be noted:

The swing bus concept. Only in the rarest of circumstances is there on a real system a bus that can be justifiably represented as a swing bus. Therefore, the swing bus necessary for the solution process represents an infringement on the realism of the overall representation. In normal load flow applications, it necessitates that the planner review the computed power injections at the swing bus and if these are not within realistic or desired limits, a new case with modified bus specifications is needed. The swing bus concept is particularly undesirable in parametric studies where the results may be influenced by the selected location of the swing bus.

Fixed generator var limits. The var capability of generators is a known function of the power output and the generator terminal voltages. Although the load flow, by specifying maximum and minimum available reactive power independently from voltage and power output specifications, allows the user to make the maximum/minimum var specifications conform to the known relationship to voltage and power, it is common practice to leave the var limits unchanged when voltage or power specifications are modified.

Constant MVA specification for load buses. This specification is justifiable during normal operating conditions for which load forecasts are made. However, for contingency studies where voltages on the individual buses may be significantly different from the normal voltages, the results may be misleading. Some load flow programs therefore, allow for conversion of constant MVA loads to alternate and hopefully more appropriate load representations for contingency studies.

Special Features

Many load flow programs have automatic adjustment features either to simulate the actual operation on the power system or to allow the specification of quantities other than the normal bus specifications. For example, a transformer

equipped with taps may be used to control the voltage on a particular bus to a specified level whether or not that transformer physically is capable of such automatic operation. The three most common automatic adjustments are:

Automatic tap changing transformers for voltage control. Normally the tap changing is controlled so that the voltage magnitude at the specified bus is kept constant. The specification is a conditional one in that the maximum tap changing range also is specified. When the automatic tap changing feature is used in connection with representation of a manual tap changing transformer, the output of the load flow program will show the tap setting that produces the desired bus voltage.

Automatic phase shifting transformers. Automatic phase shifting transformers can be used to control the power in a circuit that is connected in series with the transformer. If such controls do not exist in a system, the automatic phase shifting feature can be used to obtain the phase angle required for a specified power flow in the series circuit.

Area power interchange control. Load flow studies for normal operating conditions often require a specified power export out of an area. Programs with area interchange control have provisions for holding the power out of the area constant by controlling the power at one or more generators.

Solution Method

One of the first practical digital method for load flow solutions was published by Ward and Hale in 1956 [2]. Their method was a Gauss-Seidel iteration of equation (3.2) utilizing the partial derivative of power with respect to voltage in the voltage update equation. Several such Y-matrix iterative methods were subsequently developed [3-5] and are still in use. The main advantage of the Gauss-Seidel iterative methods is that they require little storage space. They are also easy to modify and they allow easy implementation of various kinds of adjustment features.

At any point in the Gauss-Seidel computational process a particular bus voltage is computed as a function of the bus voltages only at neighboring buses. This results in rather slow convergence and in some cases no convergence at all. An advantage of the method is that the various portions of the system are solved relatively independently such that if one problem area in the system prevents a solution, a partial solution covering the remainder of the system can be obtained, thus pinpointing the problem area. This feature is of particular importance in initial studies on a new data base.

The slow convergence characteristics of the Gauss-Seidel iterative methods led to the development of the Z-matrix methods in the early '60's

[6-8]. These methods converge more reliably and in just a few iterations, but sacrifice advantages of the iterative Y-matrix methods such as storage and speed of execution for large systems. Because of these problems and in spite of its reliable convergence characteristics, the Z-matrix method has not been widely used in the industry for general purpose load flow programs.

With the introduction of efficient sparsity programming in the mid-1960's the general Newton algorithm became computationally attractive as it could be carried out with a moderate amount of storage, had good computational speed, and had favorable convergence characteristics [9-10]. A major disadvantage of the Newton method relative to the Gauss-Seidel Y-matrix method is that when the Newton method does not converge there is no usable data to indicate the nature of the problem.

Recent developments in the Newton approach have resulted in the so-called decoupled Newton method for which advantages are claimed both in speed and in storage requirements [11-12]. The basic mathematical formulation of the Gauss-Seidel Y-matrix method, the Z-matrix method, the Newton method, and the decoupled Newton method are summarized in Appendix 1.

State of the Art

Using the full Newton or the decoupled Newton methods, single ac load flow solutions for systems of several thousand buses can now be obtained on medium sized computers within a short time. Algorithmic development has progressed to the point where the requirement of computational efficiency has been largely satisfied and where the emphasis on improvements has been transferred to user-computer interaction. In newer program designs the abilities to rapidly change case specifications, obtain a new solution and look at particular results have become of major importance. This need has led to the development of interactive load flow programs [1] where the user typically changes data on a CRT either in a dialog mode with the program or on graphic displays, then orders the solution to proceed, and selects the data he wishes to have displayed immediately after the solution process has completed. Interactive load flow programs have greatly increased the productivity of engineering effort and more importantly have permitted analysis of system problems that otherwise might have been glossed over due to the difficulty of reaching solutions within practical limits of time and effort.

Future progress in the load flow program area is likely to concentrate on 1) better interactive features for single case computations and 2) faster algorithms for use in automatic contingency analysis. The latter is discussed in Section 4.0.

3.2 Dynamic Simulation

The purpose of analyzing the dynamics of power systems is to determine whether or not a proposed system will have an acceptable dynamic

performance during a disturbance.

Ideally one would like to map the boundary between acceptable and unacceptable dynamic performance in terms of such variables as prefault network state, fault location, fault type (three-phase, single-phase, etc.), fault duration, protection response and generator characteristics. Some work has been performed to find direct approaches to facilitate the determination of such boundaries: The equal area criterion has been proposed as a basis for such analysis as has Liapunov theory. However, there are presently no realistic prospects for the applications of such methods for precise dynamic analysis of large scale systems.

However, approximate direct techniques may prove of value as an adjunct to steady state analysis during the initial screening of possible system configurations to obtain approximate relative transient stability margins. Use of the equal area criterion has been proposed to obtain estimates of system reliability. [17]

Because direct solutions are impractical for general purpose dynamic analysis, there is only one choice left, namely, time domain simulation.

It is customary in the U.S. to divide the dynamic performance into two areas of concern: Transient stability and dynamic stability. A system is transiently stable if it survives the first power swing after a disturbance, and it is dynamically stable if subsequent swings are damped. Because dynamic stability is sensitive to system damping, detailed representation of synchronous machines, excitation systems and controls is required. Dynamic stability is also sensitive to assumptions made regarding the sensitivity of load to frequency changes. Transient stability, on the other hand, can often be studied with good approximation using simplified representations. Fortunately, if a system is transiently stable, it can usually be made dynamically stable by measures that do not affect system configuration. Therefore, because system configuration is the item of most concern in planning, dynamic performance investigations can often be limited to transient stability considerations. This observation has major implications for planning study efficiency as program run time is reduced due to shorter time simulation (first swing only) and to larger allowable timesteps in the integration process.

Solution Methods

In the days of the ac network analyzer, dynamic analysis of interconnected operation was performed in the following fashion:

1. A physical model of the positive sequence electrical network including internal generator buses was connected. The internal generator buses removed from the terminal buses by the transient machine reactance were connected to voltage sources where the voltage magnitude as

well as the phase angle was adjustable. (Classical Thevenin generator model of constant voltage behind transient reactance.)

2. An initial steady state solution was obtained and current and voltages recorded.
3. A fault was introduced and the new generator current recorded.
4. Based on the new generator currents, the change in rotor angle over a specified timestep was computed for each of the generators.
5. The phase angle of each of the internal generator buses was then adjusted according to the manually computed change in rotor angle and the new generator currents recorded.
6. Steps 4 and 5 were then repeated for as many timesteps as required to determine whether or not the system was transiently stable.

When the digital load flow program started to replace the network analyzer for steady state analysis in the late 50's, it was a logical step to add the integration computations that were previously performed by hand and thus automatically obtain swing curves by a process which essentially was a digital simulation of the old ac network procedure [18].

Today, almost 20 years later, most of the large general purpose stability programs work on the same basis. That is, the simulation proceeds timestep by timestep by alternately computing a steady state load flow solution and integrating the machine differential equations. The generator currents from the load flow solution drive the integration process resulting in new internal generator voltages upon which the next timestep's load flow calculation is based.

The major differences between present and early digital simulation programs are the greater efficiency of the network solution, the trend towards even more complex machine representation, the ability to represent load with more realism, and advances in data base and user-oriented features. However, many planning studies are still performed using simplified ac network analyzer representations such as constant impedance load and generators represented by constant voltage behind transient reactance. It appears that tradition is one of the influences on program design and program use.

Limitations and Assumptions

Based on the preceding introduction and the summary of simulation models given in Appendix 2, the major assumptions and limitations of present large scale simulation programs are listed:

1. The result of a simulation run shows the system response to a specific event under specific circumstances. On the surface, the simulation approach gives only one answer: whether the system is stable or not stable. However, skilled engineers will soon learn to recognize the response characteristics of borderline stable systems and can thereby judge, at least in a qualitative way, the stability margin. Still, the applicability of a result from one case to different situations is risky, and success is dependent on the experience of the planner. This is a severe limitation of the simulation approach as computer cost and manpower efforts severely limit the number of cases that can be investigated. Only a few system conditions can be studied and for each of these conditions one must take great care in selecting severe, but credible and representative fault locations, fault types, fault durations and generator configurations. Based on the limited number of cases run, the planning engineer will have to make the judgment that the system will perform acceptably in all other credible contingencies.
2. The use of a steady state solution of the network equation is justified on the basis that the network time constants are generally so much smaller than the machine time constants that the dynamics of the electrical network can be considered immediate. The approach, however, makes the dynamic program oblivious to the dynamic phenomenon that may occur on systems that do have unusually low natural network frequencies. The problem of sub-synchronous resonance, for example, occurring when the natural frequencies of generator/turbine shafts, and low network frequencies due to series compensation, are in resonance can not be analyzed by a dynamic program of this type. For this type of problem, the network dynamics must be recognized and solved simultaneously with the machine equations.
3. In the majority of programs, the network is represented only by the positive sequence equivalent. Unbalanced faults, which are frequently the disturbance under study, are modeled approximately by adjusting the fault impedance applied to the positive sequence network. The adjustment accounts for the unbalanced effects on the positive sequence network quantities, but it does not subject the machines to the unbalanced voltages and currents that will exist in the system. In effect, all unbalanced faults studied with such tools are represented as equivalent three-phase faults.
4. While the behavior of the network itself

is well-known (if not fully represented) and machine characteristics may be verified by proper testing, it is very difficult to obtain information on the way the load varies with voltage and frequency. Load, then, is probably the most undermodeled component of the dynamic analysis. The lack of knowledge on the correct load representation is particularly of concern since there is no easy way of predicting whether a particular load representation used is conservative or not. One kind of load assumption may aid stability in one location and hinder it in another, or in a different system state.

5. The effects of off-nominal generator speed on the generator equations and of off-nominal system frequency on the network equations are neglected in many stability programs. This is probably acceptable in transient stability studies but may cause significant inaccuracies in studies dealing with large frequency deviations such as load rejections and load shedding studies.

State of the Art

The more advanced dynamic simulation programs have the capability of detailed machine representation combined with a capability of solving large networks with several hundred machines and several thousand buses.

For planning purposes as opposed to detailed design considerations, the need for improvement is in speed of execution and input/output handling rather than in more detailed representation.

3.3 Limitations of Deterministic Tools

Deterministic tools can provide information on performance for a number of specific system situations. They do not attempt to aggregate or weigh the results from the various cases into a reduced set of values that can serve as figures of merit for the overall system performance over the expected range of system situations. They merely respond to "what if" questions and can do so in great detail and with a high degree of realism and precision.

The inability of deterministic tools to arrive at figures of merit for overall performance for predicted operating conditions is their limitation. The intimate understanding of the physical behavior of the power system that can be obtained in studying one specific situation is their strength.

4.0 RELIABILITY ANALYSES

4.1 Need for Reliability Assessment Tools

Bulk power transmission systems are expanded

to meet both scheduled and unscheduled power transfer requirements. The system is expanded to meet first the scheduled requirements during normal operating conditions. Secondly, it must meet criteria for satisfactory performance during unscheduled events such as generator outages and transmission outages. The second requirement covers broadly the field of concern in transmission reliability analysis.

Criteria for bulk power systems assess reliability with two attributes: adequacy and security [19].

Adequacy is defined as a system's capability to meet system demand within major component rating and in the presence of scheduled and unscheduled outages of generation and transmission components or facilities.

Security is defined as a system's capability to withstand disturbances arising from faults and unscheduled removal of bulk power supply equipment without further loss of facilities or cascading.

Adequacy thus encompasses the steady state or post-outage analysis while security encompasses analysis of critical dynamic conditions. Adequacy assessment may be subdivided by system problems: overload of series components and voltage limit violations. Similarly security assessment may be subdivided into instability and cascading.

In terms of impact on service quality, inadequacy may result in partial load curtailment while the insecurity may result in total system shutdowns.

Power system inadequacy or failure in supplying the load demand for a specific contingency can be described by three attributes:

1. Frequency of contingency.
2. Time duration of contingency.
3. Severity of contingency.

Severity should measure the degree of system inability to supply the load demand; that is, load curtailment. In case of instability and cascading the load curtailment is total for the affected portion of the system.

Deterministic Reliability Criteria

The criteria used for reliability in the expansion of a transmission system may be either deterministic or probabilistic.

At present, most planning procedures employ deterministic contingency or disturbance criteria for both dynamic and static assessment [20]. Such criteria are applied in a "go, no-go" framework. That is, system response must fall within prescribed limits relative to maintenance of synchronism, permissible ranges of voltage and frequency, and permissible limits on component

loadings. Load flow and stability programs are used to verify that a system meets the defined criteria. Normally, deterministic criteria do not explicitly refer to any of the three attributes describing the system's inability to meet the load demand in a satisfactory fashion. Rather the criteria are concerned with limiting system trouble caused by specific contingencies without explicit consideration of outage statistics.

However, although deterministic in nature, the criteria are based on the relative likelihood of disturbances and their consequences. Typically, criteria require that the system shall be able to withstand frequent disturbances without affecting system operation while some loss of service is allowed for the less credible contingencies. Also since the set of disturbances used is of necessity very limited, there is a requirement that each disturbance tested be representative for a class of credible contingencies.

Two important questions concerning deterministic planning criteria are whether they assure reliable system performance and whether alternative system configurations which are designed to meet these criteria result in equally reliable performance.

Probabilistic Reliability Criteria: Indices

Probabilistic reliability procedures attempt to assess the risk of system failure on the basis of outage statistics of system components. Such procedures can in principle assess reliability in terms of frequency, duration and severity attributes of contingencies. If these attributes were evaluated for all significant contingencies, several bulk power supply reliability indices could be easily computed. The two following monoparametric indices have been found to yield particularly useful measures of relative performance of system alternatives [19]:

Bulk Power Interruption Index:

$$P = \frac{1}{C_{MX}} \sum_{i=1}^N F_i C_i \quad (4.1)$$

Bulk Power Energy Curtailment Index:

$$E = \frac{1}{C_{MX}} \sum_{i=1}^N F_i C_i D_i \quad (4.2)$$

where:

F_i = Frequency of contingency i (year^{-1})

D_i = Duration of load curtailment caused by contingency i (hours)

C_i = load curtailment due to contingency i (MW)

C_{MX} = Annual Peak Load (MW)

These indices offer useful measures for evaluating present system performance as well as evaluating future system plans. Further, and most importantly, the two indices are suitable for evaluation of bus, system, and pool or regional reliability performance.

Other indices such as frequency or probability measures of system problems (overload, voltage limit violations, etc.) are also meaningful in their own right, but they do not directly relate to the impact on the customer -- they do not distinguish between system trouble events that cause load interruptions and those that do not.

Procedures for Reliability Assessment

Reliability assessment procedures contain one or more of the tasks shown in Figure 4-1. The particular sequence of tasks shown is a logical one for a comprehensive probabilistic procedure based on contingency analysis [21]. The figure emphasizes the need for detailed system analysis within the reliability assessment process. Important for assessment of contingency significance are the remedial measures required to alleviate the contingency effect and the consequent impact upon load served. The fact that a given contingency at a given loading level results in system stress beyond loading or voltage limits is not sufficient to describe the impact of the contingency. For moderate overload or out-of-limit voltage, generation redispatch, tap changing, and reactive adjustment are feasible remedial measures.

For severe overload, cascade trip of overloaded elements may be required to properly represent system response. Hence, unstable or cascading consequences of certain contingencies can result in larger losses of load than the remedial measures for the static overloads would indicate. This effect may be modeled by allowing a specified time for system reconfiguration and load curtailment following cascade tripping.

The general procedure outlined in the preceding does by no means reflect the state of the art of reliability analysis of large scale transmission systems. Rather it should be regarded as a goal toward which some contributors to the improved computations in the reliability field are working. In fact, most of today's reliability techniques do not contain remedial considerations and none treat the security problem in an adequate fashion.

Deterministic reliability analysis normally involves Tasks 1 and 2 only, but could in principle include Tasks 3 and 4 as well. If any one of the selected contingencies results in an unacceptable system situation (or impact on load(s)), the system would need to be strengthened.

FIGURE 4-1

PROCEDURE FOR RELIABILITY ASSESSMENT

4.2 Real Power Contingency Models

On many systems, preliminary evaluation of network configuration as well as the siting of individual series elements can be made without reference to voltage conditions and var requirements. This allows one to take advantage of the linearity of the power-angle relationship as expressed in equations (4.3) and (4.4).

$$\underline{P} = [B]\underline{\theta} \quad (4.3)$$

$$\underline{\theta} = [X]\underline{P} \quad (4.4)$$

DC Load Flow

As explained in the discussion of decoupled Newton load flow in Appendix 1, the vector of equation (4.2) can be solved very quickly given the network series reactance (x_{ij}) and specified power injections. With the angles known, the power flow in each circuit element is obtained from (4.5).

$$P_{ij} = \frac{\theta_i - \theta_j}{x_{ij}} \quad (4.5)$$

The solution obtained is commonly called a dc load flow solution, referring to the dc network analyzer which was capable of solving the same type problems using a resistance network where each series resistance was proportional to the series circuit reactance. With this network representation it has become possible to carry out the thousands of load flows that are required for comprehensive contingency analysis on large scale systems. The adequacy assessment obtainable with this representation is of course limited to overload related system problems.

Distribution Factors

Equation (4.3) lends itself to the precomputation of sensitivity factors called distribution factors. Such distribution factors have long been used to rapidly compute the change in real line flow with change in bus power injection and the change in line flows for a single line outage [22]. The distribution factors used for these two applications are referred to as "a" and "d" coefficients respectively:

$$a_{l,i} = \frac{\text{the change in real power flow on line } l}{\text{the change in real power injection on bus } i} \quad (4.6)$$

$$d_{l,k} = \frac{\text{the change in real power flow on line } l}{\text{the real power flow on line } k \text{ before it opened}} \quad (4.7)$$

The derivation of such distribution factors is described in Appendix 3. Their application covers operation as well as planning studies.

The most serious limitation of the application of these factors for planning studies is the fact that they are valid for only one network configuration. When the network changes, such as for a line outage, new factors need to be computed. As explained in Appendix 3, the coefficients may be modified for one line outage such that two line out conditions can be looked at, but then the process may not be much more efficient than the modification of the triangularized B-matrix in the dc load flow representation. Such modification may consist of a complete refactorization or use of a modification technique such as the Sherman-Morrison Algorithm [23] described in Appendix 4.

Transportation Models

While the choice between the use of dc load flow and distribution factors is a matter of versatility and efficiency only, there is a third category of linear models which are referred to as transportation models. These models, used in some transmission expansion programs, observe Kirchhoff's current law, but not Kirchhoff's voltage law. In other words, the method observes flow constraints imposed by network configuration, but not by the impedances of individual branches.

4.3 AC Contingency Models

Although the real power flow approximation may be sufficient for the early planning studies of many systems, voltage and var conditions must eventually be studied. On some systems [24] with remote generation, where the voltage/var considerations have a major influence on the network configuration, the use of the real power contingency tools may be inadequate even in the initial stages of a planning study. There is, therefore, a need for techniques that can rapidly calculate ac load flow quantities for specified contingencies. Three different approaches to fast approximate ac load flows have been identified and their characteristics summarized in this section. These are:

1. Decoupled Newton Load Flow
2. Z-Matrix Method
3. Sensitivity Methods

Decoupled Newton Load Flow

Variations of the decoupled Newton Load Flow described in Appendix 1 have been proposed for fast approximate ac load flow computations [12,25]. The method is iterative, but since state independent system matrices are used, no refactorization of these matrices is required between iterations.

The distinct advantage of decoupled load flow methods for fast approximate ac load flows is that a solution of specified accuracy is obtainable. Therefore, for most outages where one single iteration is adequate [12], high speed is obtained while iterative solutions will automatically be provided to obtain adequate accuracy for contingencies with extra large voltage excursions. This latter point is important, since these are the very contingencies one needs to worry about.

In both References 12 and 25, the Sherman-Morrison Algorithm is used to simulate line outages in terms of bus injections, thus avoiding the refactorization of system matrices for each contingency.

Z-Bus Method

As discussed in Section 3, the Z-Matrix method is not competitive with Full Newton or Decoupled Newton techniques for general purpose load flow or contingency studies where the entire load flow solution is desired. The strength of the

Z-Matrix approach is that each element of the matrix by itself gives the sensitivity between a current injection at a bus and the voltage at the same or another bus. Thus, if on a large system one is interested only in the voltage at a few buses or the flows on a few lines for a variety of conditions, it may well be that a Z-matrix procedure can be found that is significantly faster than competitive methods. Philosophically, Z-matrix approaches may be put in the same class as distribution factor methods. By precomputing network related factors (Z-matrix elements or derivatives of these) one can rapidly compute selected voltages, currents or powers for the type and scope of system conditions covered by the precomputed factors.

A Z-Matrix approach proposed by Brown in 1977 [26] is described in Appendix 4. The procedure is capable of high speed approximate evaluation of one bus voltage for any line outage once a special Z-Matrix associated with this bus has been constructed. The procedure may thus be competitive if the voltage at a small number of buses needs to be evaluated for a great number of contingencies. The method is dependent on the existence of a constant voltage bus near the bus for which voltage is to be computed and fairly constant X/R ratios throughout the system. Also, the method is restricted to a constant impedance load representation.

Sensitivity Methods

The inverse of the Jacobian Matrix is referred to as the sensitivity matrix as it gives the sensitivity of voltages to bus injections. See equation (4.8):

$$\begin{bmatrix} \frac{\Delta \theta}{\Delta V} \end{bmatrix} = \begin{bmatrix} J \end{bmatrix}^{-1} \begin{bmatrix} \frac{\Delta P}{\Delta Q} \end{bmatrix} \quad (4.8)$$

With much the same philosophy as one applies to distribution factors or the Z-Matrix approach described in the preceding, one can use these sensitivities to estimate bus voltages as a function of power injections (generator and load changes) [27], or as a function of network configurations. Reported procedures [28,29] utilize the Jacobian matrix obtained on the last iteration of a full Newton load flow. The methods are therefore based on the assumption that linearization around the base case operating point can be used to compute the change in bus voltages due to a contingency. Therefore, it seems that one may expect accurate results when the outage is not critical from a voltage standpoint, and progressively less accuracy as the voltage excursion increases.

State of the Art

Several methods have been proposed for the fast approximate computation of ac quantities required for contingency evaluation. Although not the fastest, the decoupled Newton approach appears

to be the current method of choice for practical planning studies. The method's main advantage is its versatility. The program can be used in the following different modes:

1. To obtain a dc load flow solution by one P0 solution from flat start.
2. To obtain approximations to the P0 solution for changes to the base case by one P0 solution starting with the base case.
3. To obtain approximation to the full ac solution for changes to the base case by one P0 and one QV solution.
4. To obtain a full ac solution for base case or change case with the minimum number of iterations consistent with a specified accuracy requirement.

4.4 Probabilistic Reliability Analysis

While deterministic reliability testing is based on system performance criteria which must be met for specified contingencies, probabilistic reliability analysis makes it possible to judge systems based on risk criteria or reliability indices. Reliability indices which reflect not only the risk of system trouble, but also the estimated consequence in terms of interrupted load were discussed in Section 4.1. Figure 4-1 shows how such information can be obtained through probabilistic contingency analysis. The figure is in principle applicable to both adequacy and security analysis. However, it may not be practical to carry out security assessment in this manner. Stability tests, for example, add three new dimensions to the reliability assessment problem: fault location, fault duration and fault type. The probabilistic ramification of this, as well as the computational effort involved in realistic assessment of system stability probably excludes the formation of risk indices for stability by the process shown in Figure 4-1. A possible alternative is estimation of the boundary of instability in terms of fault type, fault duration, and fault location followed by an estimation of the frequency of events on the instability side of the boundary. This approach has been attempted on a limited scale system [24]. A discussion of the probabilistic aspects of stability and a proposed transient stability index is given in Reference 17. There are presently, however, no practical approaches suitable for probabilistic evaluation of large scale system stability. Therefore, the remainder of this section will deal only with adequacy assessment.

System Models for Adequacy Assessment

The system model consists of load and network models and component representation.

A full load model, considering both active and reactive loads, includes:

1. Load distribution among buses,
2. Variation of load with time of the day, day of the week, season and over the years comprising the planning period, and
3. The functional relationship of load and voltage.

The network model contains data required for normal load flow analysis and other information relevant to circuit switching such as substation configuration and relay protective systems.

Component representation includes failure or outage statistics in terms of frequency and duration of both unscheduled (automatic) type outages and scheduled (prearranged) outages. For computational convenience as well as lack of data, most adequacy assessment approaches assume that simultaneous outages can be treated as independent events. Recent outage data indicate that the statistical dependency of simultaneous outages must be considered to obtain realistic estimates of reliability indices. Typical cases where the assumption of independence is invalid are circuits on a common tower or a common right-of-way, and circuits terminating in the same substation.

Proposed Methods for Adequacy Assessment

Of various approaches for adequacy assessment, three will be discussed here:

1. Contingency enumeration method
2. Composite method
3. Contingency level method

Table 4-1 summarizes the features of representative methods for each of the three approaches listed. There is a strong interaction between algorithms, the network model and the measures and means for selection, assessment, and accumulation of risks of failure.

Contingency Enumeration Methods

The contingency enumeration methods follow Figure 4-1. Some are based on dc load flows [30], others on ac load flows [31,32]; most are intended to be used on a specified set of contingencies or on all first contingencies, but at least one approach [30] applies automatic contingency selection as a means of reducing the number of contingencies that need to be evaluated by load flow computation.

For a constant load level L , the risk of failure indices for buses is given by:

Probability of failure at bus k

$$= \sum_j [P(B_j) \cdot P(\text{Bus } k \text{ fails} \mid B_j, L_k)] \quad (4.9)$$

Frequency of failure at bus k

$$= \sum_j [F(B_j) \cdot P(\text{Bus } k \text{ fails} \mid B_j, L_k)] \quad (4.10)$$

TABLE 4-1

PROBABILISTIC ADEQUACY MODELS

METHOD	REP.	NETWORK MODEL	ELECTRICAL MACHINE MODEL	PERFORMANCE INDICES	REMEDIAL ACTION STRATEGY	CONTINGENCY SELECTION PROCEDURE	COMPONENT PROBABILITY MODEL	SYSTEM PROBABILITY MODEL	PROBLEM SIZE REPORTED	TRANSMISSION CONTINGENCY LEVEL	GENERATION CONTINGENCY LEVEL
Contingency Enumeration (Automatic Contingency Selection)	[20]	DC Load Flow	Capacity Outages Considered	Bus Failure Prob., Freq. Bus Load Curtailment, Branch overload	LP. Minimization of Load Curtailment with Gen. & U Shift Remedial Dispatch	Automatically Selected by Overload Index	Individual Circuit F&D, Individual Gen. F&D, Common Mode Circuit and Generation Events	Explicit Enumeration for Transmission States Plus Accumulated Bus Capacity States & Area Reserves	Intermediate 1500 Bus	3+	5
Composite	[33-37]	AC Load Flow	Capacity Outages Considered	Bus Failure Prob., Freq. Bus Voltage & Branch Overload	None	User Selected	Individual Circuit F&D, Individual Gen. F&D, Independent Events	Explicit Enumeration of Transmission States and Accumulated Bus Capacity States	Small 20 Bus	2	2
Contingency Layer Method (Inner-connection Planning)	[3a]	Base Case + Dist. Factor	No Capacity Outage	Simultaneous Interchange Capability Duration Curve	L.P. Maximization of S.I.C.	User Selected Set	Average Circuit Probability	Combinatorial Circuit States	Large = 4000 Bus	3-4	-

These are sufficient expressions for computing reliability indices that are based on a single load level and that do not include consideration of remedial action. However, if some degree of simulation of the operating response to outages is included, the probability of failure of bus k becomes a function of the dynamics of the outage event. For example, if outage state B_j denotes lines x and y out, it may be important to distinguish between the case where x and y go on outage simultaneously, and the case where x is already out when y goes out.

An even more important problem arises when load variability is included. It is quite clear that the risk of failure at bus k is normally much higher if outage state B_j occurs at load level L_0 than if the load changes from some higher or lower level to L_0 while the outage state is B_j . Again the reason for the importance of this distinction lies in the fact that, in the latter case, there is time to apply remedial actions such as starting up new generation or speeding up maintenance on outaged circuits.

Thus the assessment of the term:

$$P\{\text{failure at bus } k \mid B_j, L_0\}$$

is highly complex. It should also be noted that the possibility of failure during transfer into load level L_0 is not included in equation (4.10).

It may be concluded from the preceding that the road towards the computation of more realistic reliability indices is not a straightforward one; perhaps not even on the conceptual level.

The method described in Reference 30 is representative for the state of the art of contingency enumeration methods. Three distinguishing features of this method are:

1. Task 1 in Figure 4-1, Contingency Selection, is performed automatically.
2. Task 3 in Figure 4-1, Remedial Action in terms of overload minimization, generation dispatch and phase angle regulation shift, may be performed for each contingency causing overloads.
3. Tasks 4 and 5, Computation of Reliability Indices relating to impact on load, is performed through load curtailment minimization.

The method which is referred to as the "Automatic Contingency Selection Method" uses a dc load flow model and represents individual branch outage models and individual generating unit capacity outage models. Performance indices include bus failure, probability and frequency, expected bus load curtailment, and branch overload. The strategy employed is a linear program method which minimizes the load curtailment necessary to remove overloads. Contingency selection is automatic through the use of a performance index gradient to rank the impact of capacity and branch outages upon the distribution of flow in the transmission system. See Appendix 4. Reference [30], a concise summary of the approach, is reproduced in Appendix 5.

Composite Method

The composite methods [33-37] are based on the explicit enumeration of transmission states and accumulated generator bus capacity states. The method uses ac load flow solutions and has been applied to small systems only. The outage rates for individual branches and generating units are included. The performance indices for this model include bus voltage out of limits and branch overloads. There is no provision for generation remedial shifts nor use of any other strategies to

minimize overload or abnormal voltage conditions. The applicability of this method to large scale systems has not been proven, but reference is included here due to its central place in the literature of transmission reliability analysis.

Contingency Level Method

This technique, reported by Landgren, et al., in a paper [38] entitled "A Reliability Approach to Interconnection Planning", develops interchange capability in terms of a capability duration curve. The method uses generic line outage data, a simplified average line model with the binomial theorem to form a prediction for risk of outage of n elements out of m . The linearized power flow technique is applied to very large network problems making use of linear programming techniques to determine the maximum simultaneous interchange capability under specified outage conditions. Contingencies are selected from a large user-identified list of branches critical to outage and overloads.

The outage probability model used in this approach takes two significant steps in departure from the specific state enumeration method cited previously. First, the assessment is concerned with the risk of occurrence of at least one event of interchange curtailment during a major transmission period considered to be a specific fraction of a 24-hour period. Second, the assessment is concerned with the generic risk of single, double, and higher level contingencies. The outage model for each circuit is considered as modeled suitably by a typical circuit having average annual tripouts and average forced outage duration. Given the two state model with outage probability p and outage rate λ/yr , the outage of n non-specified circuits out of m is:

$$P(n,m) = \left(\frac{n}{m}\right) p^n (1-p)^{m-n}$$

and the probability of n specified circuits out of m is:

$$P(n,m) = p^n (1-p)^{m-n}$$

Reference [38] employs a model for the risk of at least one event during a major transmission period of duration " t " as:

$$P_1(t) = p + (1-p) (1-e^{-\lambda t})$$

wherein the first term accounts for the risk that the element is out at the start of the major transmission period. The second term is offered to account for the risk of the element failing during the period t , given that it was available at the start of the period. λ is the constant failure rate.

The approach sacrifices the capability to identify the risk of specific branch outage events for the gain of the ability to finesse the dimen-

sion of the combinatorial problem involved in dealing with specific branch outage events.

In the example cited in Reference 38 for 5 critical branches there are:

1 event	all elements in
500 events	1 element out
124750 events	2 elements out
2.0709×10^7 events	3 elements out
etc.	

Other Methods

Not included in this discussion of bulk power supply adequacy models are the flow graph models and continuity models that have been applied successfully to distribution and substation analyses. These models were not regarded as sufficiently representative of the power flow problem to be considered for bulk power supply adequacy assessment. It should be mentioned that the flow graph model has been successfully utilized for the study of multi-area capacity reserve assessment [39,40].

4.5 Monte Carlo Simulation

In transmission planning studies, the use of Monte Carlo simulation methods allows very detailed modeling of the generation and transmission components as well as the system demand and operating practices. In the Monte Carlo method, a state of the system is chosen by determining generation and transmission availability and system loads as random variables chosen in accordance with their probability distributions and then one or more system performance indices are evaluated for that operating state. This procedure is repeated many times and an estimate of the mean value of the performance indices is determined. The accuracy of this method increases as the number of trials increases, and simulations involving several thousand trials are typical.

Monte Carlo simulation has been used extensively in Europe [41-44] but not in the United States.

Description of the Technique

In the Monte Carlo method, network states are simulated by means of random sampling on the availability of generation and transmission components as well as on the demand. As an example the simulation of a component with an availability of 0.9 is achieved by selecting a sample of a random variable x which is uniformly distributed on the interval $\{0,1\}$. The component state is then assigned according to the rule:

$0 \leq x \leq 0.9$	component available
$0.9 < x \leq 1$	component unavailable

In the European studies, the electric network is modeled using the linear dc load flow model. For each system state examined, a linear

program determines the generation dispatch which minimizes the load curtailed while recognizing the constraints of flow on transmission lines and of generation. The key to effective Monte Carlo simulation is the efficient execution of the linear program which determines the generation dispatch. The linear program to be solved in this case is a large one because of the large number of constraints imposed by both generation and transmission. One algorithm used to solve this linear program efficiently is described in [44]. The method exploits not only the sparse structure of an electric power network, but also the fact that in a situation involving transmission system component overloads, only a very few of the hundreds or perhaps thousands of components will be overloaded. The linear program to be solved in order to determine generation dispatch may be stated as

Minimize $\phi(p,c)$

Subject to: $\theta = [X] (p-c)$

$$\sum_{i=1}^N p_i = \sum_{i=1}^N c_i$$

$$p_i^0 \leq p_i \leq p_i^1$$

$$0 - c_i - c_i^1$$

$$-\theta_l^0 < \theta_l < \theta_l^1$$

where:

p_i is the active power generated at node i

c_i is the active power consumed at node i

θ_l is the phase difference across transmission line l

$\phi(p,c)$ is a linear function of p and c

N is the number of network nodes

Superscripts 0 and 1 indicate low and high limits, respectively.

The method proposed in [44] consists of replacing this original linear program by a series of linear programs of reduced size. The first linear program neglects all transmission line constraints. After the generator dispatch is calculated, transmission line constraint violations are checked. If no transmission line constraint violations occur, the solution is complete; otherwise those overloaded transmission line constraints are included and a new linear program is solved. This process is repeated until there are no constraint violations. The algorithm referred to as the relaxation algorithm is depicted in the flowchart of Figure 4-2.

FIGURE 4-2

FLOWCHART OF RELAXATION ALGORITHM FOR MONTE CARLO SIMULATION

Several different indices of transmission system performance of both the global and local type, may be evaluated simultaneously using the Monte Carlo simulation method. Some typical indices evaluated by this method include

- o Expected value of system load not served
- o Probability of not meeting system demand
- o Expected value of operating costs
- o Expected value of power losses
- o Expected value of hydro power consumed
- o Probability of transmission line not operating at its constraint
- o Expected value of bus load not served
- o Probability of not meeting bus demand

The accuracy in the estimate of any one of these performance indices depends both upon the number of trials and the frequency of occurrence of events which affect the particular index. For example, accurately evaluating the probability of not meeting system demand will require many trials if events which cause the failure to meet system demand occur very infrequently. The accuracy of estimating a performance index is proportional to the square root of the number of trials of the simulation. That is to say, in order to double the accuracy of the estimate of a performance index one must perform four times as many trials. This unfortunate result is a major limitation of the Monte Carlo method. Appendix 6 describes one way of improving the accuracy of estimation or, conversely, reducing the number of trials.

4.6 Reliability Analysis and Worth of Service Availability

The power system reliability analysis problem may be formulated in four different ways in order of increasing realism, complexity, and completeness:

1. Deterministic. System alternatives must meet criteria specifying allowable system response to specified contingencies or disturbances.
2. Probabilistic - System Trouble. System alternatives must meet criteria specified in terms of probabilistic reliability indices reflecting risk of unacceptable system response.
3. Probabilistic - Load Curtailment. Same as 2., but criteria specified in terms of risk of load curtailment.
4. Effectiveness Analysis. Balancing incremental system cost and worth of improved reliability. This is based on the widely accepted concept that the proper level of service quality should be defined by the balance of incremental worth of service quality improvement and incremental cost of providing that improvement.

The limitation of the deterministic approach (1) is that one is explicitly only looking at the initial system problems for a few "arbitrarily" selected contingencies. The probabilistic approach (2) aims at eliminating the "arbitrary" contingency selection by attempting to look at all significant contingencies. Approach (3) looks deeper into the problem in that it is explicitly concerned with the impact on the customer. However, the criteria used for system acceptance are still "arbitrary." They are not determined based on explicit evaluation of the worth to the customer of changes in reliability. Approach (4) attempts to remove this last bastion of "arbitrariness" and close the loop of the reliability analysis problem. (Note, the word arbitrary has been used here to make a point. The criteria used in any process are, of course not arbitrary, but based on a mixture of judgment, tradition and experience.)

From the customer's point of view, electric power supply system effectiveness has at least three ingredients:

1. Worth (or utility) of service
2. Cost of service
3. Environmental impact

The criteria for effectiveness as seen from the utilities and the regulatory agencies are largely constrained to coincide with those of the consumer but they are obliged to consider a whole

set of secondary constraints which may not be transparent to the consumer, e.g., capital limitations. Neglecting such constraints for the moment, the anatomy of the problem that system effectiveness analysis must deal with may be explored in reference to Figure 4-3.

FIGURE 4-3

REFERENCE DIAGRAM FOR EFFECTIVENESS ANALYSIS

As illustrated, system configuration and operating criteria (R) determine service quality, cost of providing the service, and associated environmental impacts. If service quality can be translated into worth measures, then the power system may be expanded and operated according to objective and subjective comparisons of worth, cost and environmental considerations. We suggest that, conceptually, Figure 4-3 is a fair representation of the feedback mechanism in the evolution of power supply systems, and that it is a valid frame of reference for the development of procedures for system effectiveness analysis.

There are three major obstacles in the application of reliability analysis in the fourth problem formulation.

1. Assessment of worth of service quality. As described in Appendix 7, this is in itself a most difficult task.
2. Separation of reliability related aspects from the overall system optimization problem. For example, the addition of a new circuit may be justified partly due to economic gains (reduced operating cost) afforded by new transfer possibilities and partly due to the worth of increased system reliability.
3. Development of efficient tools for computation of sensitivity of system cost with respect to service quality as expressed through reliability measures.

The separation of reliability related aspects from the overall system optimization problem as expressed in 2. may well prove impractical, in which case reliability and operating cost aspect must be treated simultaneously, thereby greatly

enlarging the scope and complexity of the analysis tool.

Since the industry has only recently started to apply probabilistic concepts to the planning of large scale transmission system studies, it is not likely that tools suitable for complete effectiveness analysis on large systems will be developed any time soon. However, the problem formulation is relevant and pilot studies of this type are being performed with respect to generation expansion and using existing planning tools. For example, Electrical Week of May 15, 1978 contained a news bulletin with the headline, "How Much is Enough? Reserves of 20-35 percent may be cheaper for customers." The note quoted an EPRI study entitled, "System Reliability - How Much is Enough?" which concluded that,

--- Consumer costs are lowest with too much capacity rather than too little. This is the result of consumer outage costs - costs which do not appear in the price charged by a utility. It is also partially the result of operating savings realized by the utility as a result of the additional capacity.

The bulletin also contains the following statements which should be equally applicable to transmission planning:

--- The EPRI model can accommodate different outlooks on demand growth, outage costs, and environmental costs, and it can provide a 'logical framework' for discussing power needs at licensing hearings.

An estimated cost of outage of \$20/kwh is quoted for the 1977 blackout in New York City.

Since most widespread blackouts are caused by transmission related events, the industry's interest in this problem formulation is bound to persist.

5.0 TRANSMISSION SYSTEM EXPANSION MODELS

The preceding sections have considered tools for analyzing the performance of specific transmission system alternatives. Even for such analytic tools the complexity and the dimensionality of large power systems are such that simplifications must be made to reduce the computational burden. It is obvious then, that rather drastic simplifications in system representation and performance criteria are required for any attempt at automatic synthesis of future transmission expansions. It is also clear, that any claim to optimality for the solution of a particular method can only be made in the mathematical sense. That is, the "optimal" system is that which minimizes a performance function (objective function) based on a specific system representation and a specific set of constraints. Since the scope of representation of an automatic expansion planning tool is

narrower than that of a transmission system planner, the tool's optimal system is not necessarily the best from the planner's point of view.

Therefore, to utilize such a tool meaningfully, the planner needs to be keenly aware of the assumptions and limitations particular to the model he is using. It also suggests that the best model to use may be a function of both system characteristics and the relative importance of various performance aspects and constraints.

Automatic expansion models can be divided into three main categories.

1. Single stage optimization models. For these models, the "optimal" system expansion is typically the minimum investment cost system that can meet system requirements at a particular time in the future.
2. Through time or time-phased optimization models. These models attempt to recognize the increasing system requirement as a function of time and arrive at an overall minimum cost expansion where cost may include operating cost in addition to time weighted investment costs.
3. Heuristic models. In these models, mathematical optimization techniques are replaced by heuristic logic to arrive at feasible and economic system alternatives.

5.1 Single Stage Optimization Models

Single stage optimization models are capable of computing the optimal transition from one system stage (e.g. present) to a future system stage (e.g. a distant future year: horizon year). However, the optimization process does not consider the timing of installations resulting in the "optimum" system. Single stage models may, however, be used in a year by year mode to arrive at a feasible and reasonable through-time expansion. The resulting expansion may have an optimal transition from one stage to the next but cannot claim overall expansion optimality.

Single stage models can also be used in a two-step fashion where the first step determines the system expansion from the present (known) system to the horizon year and the second step is a year by year expansion where only system additions present in the horizon year are considered. Alternately, one can start with the horizon year and "unplan" towards the present (known) system.

The following approaches to single stage optimization expansion models are discussed in this report:

1. Gradient Search [45,46]
2. Linear Programming [47-49]
3. Integer Programming [50-53]

Gradient Search Method

The gradient search method described in Appendix 8 [45,46] is a nonlinear mathematical programming formulation of the expansion problem. The model objective is the minimization of a performance index of form [46]:

$$PI = \sum_{l=1}^L \left(\frac{1}{2n} W_l (P_l/P_l^{(d)})^{2n} + K_l B_l \right) \quad (5.1)$$

where:

W_l = a real non-negative weighting function for circuit l ,

P_l = the real power flow in circuit l ,

$P_l^{(d)}$ = the real power flow capacity of circuit l , specified as input data,

B_l = the susceptance of circuit l ,

n = a positive integer, specified by the user,

K_l = a real non-negative weighting factor which reflects the cost of line additions for circuit l ,

L = the number of circuits modeled.

Note that the first term is small if there are no overloads, but increases rapidly for overloads on one or more circuits. The second term represents circuit cost. By means of the technique described in Appendix 8, it is possible to compute the partial derivatives $\partial PI / \partial B_l$ for all right-of-way alternatives in the system by the solution of only two dc load flows. The partials are also available for designated future rights-of-way where there are currently no circuits ($B_l=0$). Based on this sensitivity information, a gradient search algorithm allocates new circuits in a way that minimizes the performance index. That is, the new circuits that are most effective in reducing overloads, and at the same time are not too costly, will be added. The process is iterative, allowing for the removal of added circuits that may become superfluous as the system progresses.

Results available to the user include an iteration by iteration summary of the network changes that were made, a summary of network performance in terms of overloads, a final summary of network changes and installed cost of additions, and a final dc load flow solution.

The use of a gradient directed search to minimize a system performance index requires supporting logic to adapt the method to the integer nature of the problem. There is no guarantee that an absolute minimum will be found when the search terminates. In addition, it is likely that the performance index has local minima. To avoid

premature termination of the search at a local minimum, several expansion combinations along the gradient projection are investigated.

Linear Programming

This approach, described by Garver [47], employs linear programming and linear flow models in the formulation of an automated transmission system planning algorithm. This algorithm forms the basis of a transmission system estimation program which has been designed to produce both "horizon year" and "through-time" transmission plans.

The algorithm minimizes an objective function which is equivalent to the sum of the circuit lengths (guide numbers) times the magnitude of power which they transport. The circuit power flows are computed using a "linear loss function network model" which is similar to a transportation model in that it employs Kirchoff's current law, but not Kirchoff's voltage law to define flows. As a result, the circuit flows predicted by this model may vary considerably from those predicted by an ac or dc load flow program.

In addition to conventional circuits which can only be loaded up to their capacity limit, the flow model employs overload paths in which power can flow if necessary. This allows the program to visualize where circuit additions are needed.

The algorithm expands the network one circuit at a time until there are no overload paths that carry flow. After each addition, a new flow estimate is computed which minimizes the accumulated products of power flow and guide number. The path with the largest overload is chosen as the location for the next addition.

The computer program can be executed in two stages -- the horizon year stage and the through-time expansion stage. The first stage deals with obtaining the optimum network for the final year of the study. The second stage determines a step by step expansion pattern from the present network to the horizon year network. Both stages use the same optimization criteria. Thus, the through-time optimization stage does not consider the timing of revenue outlays.

When the network expansion is complete, the system is usually checked using an ac load flow program. Results of studies [48,49] have indicated that the algorithm is capable of producing transmission system expansion plans that will support the power flows required to satisfy the future generation and load profiles. The method is summarized in Appendix 9.

Integer Programming

One weakness of nonlinear and linear programming methods is the requirement that all variables be continuous. Since transmission components are added in discrete steps, some kind of round-off procedure must be used. Integer

Programming (IP), on the other hand, inherently recognizes the discrete nature in the transmission expansion problem.

One of the earliest reported works on the application of IP to transmission expansion was by Knight in 1960 [50]. Due to the dimensionality of the problem and the poor performance of the integer programming codes available at that time, the method was viewed to be impractical. However, in recent years, more efficient IP procedures have been developed and used successfully outside the electric utility industries. Hence, there has been a renewed interest in the use of IP to develop optimal transmission expansions.

The term integer programming (IP) applies to formulations in which integer variables are present. In order to distinguish the various categories of IP, the following definitions are provided. Pure integer programming (PIP) implies that all variables are integer. In mixed-integer programming (MIP) only some of the variables are required to be integers. MIP may be divided into mixed-integer linear programming (MILP) for which all functions are linear, and mixed-integer non-linear programming (MINP) for which some functions are non-linear. In most situations, a general IP problem may be solved more easily and quickly through the use of 0-1 programming in which all integer variables take on values of either 0 or 1. Transmission expansion falls into this class of IP since each new component is either added or not added to the network.

As explained in Appendix 10, IP techniques include the use of branch-and-bound search processes to find the least expensive feasible expansion. This is achieved through successive evaluation of circuit additions until all possible combinations of additions have been examined implicitly. Although only a small fraction of the 2^N (N = number of circuits) possible circuit combinations are explicitly evaluated, computational time is still excessive even for medium sized systems. The use of a screening procedure before the search reduces the computational effort by identifying potential effective circuit additions and excluding ineffective circuit additions. Also, by sequencing the search in a proper manner, it is possible to arrive at the optimal expansion more quickly.

In general, computational effort increases rapidly with problem size. Reported studies [51] on systems with about 60 buses, 120 lines and 20 rights-of-way, have shown that computational efforts appear to be reasonable. Nevertheless, further tests are needed on larger systems.

It should be clear from the preceding that the integer programming approach encompasses a class of transmission expansion formulations that, in whole or in part, explicitly treat the addition of circuits as a discrete problem. Within this framework the system representation and constraints used may vary widely.

Although the branch-and-bound search process finds the least expensive circuit combination among those analyzed, the search is generally limited to conserve computer time. Therefore, if there is a possibility that the limited search techniques and rules can exclude the optimum circuit combination from consideration, the resulting expansion is not necessarily optimal.

Comparison of Single Stage Optimization Methods

Each of the proposed approaches have their strengths and weaknesses. A general weakness of all such models is that both the system representation and the expansion objectives are of necessity, much simplified and do not cover the range of concern a planner may have. Beyond that, the gradient search method has problems with local minima of the performance index, the system representation used in the linear programming model may be too crude for many systems, and the present integer programming schemes may not be practical for large scale systems.

The basic problem inherent in any single stage expansion process is that it does not consider the timing of installations. One commonly observed effect is that when the time period of expansion is short, the programs tend to add many low-capacity circuits. Conversely, when the time period is long, the single stage optimum approach dictates the addition of fewer, but high capacity circuits.

5.2 Through-Time Optimization

Since the installation of a line does influence future system operation and the accumulated cost, it is essential for the planner to evaluate the cost for an expansion which identifies the timing for the installation of new elements through the time period. This will allow the inclusion of inflation and interest rates as well as year by year operating cost in the comparison of different expansion plans. Such features are only available in the through time or time-phased approach to automatic transmission expansion programs.

Both Integer Programming (IP) and Dynamic Programming (DP) have been applied to the through time optimization problem. An extension of the integer programming approach used in single stage optimization to through-time optimization is described in Appendix 10 [52,53]. However, because the computational effort for these methods increases rapidly with system size and the number of stages, they may not prove practical on large scale systems. Dynamic programming has been applied to a variety of through-time or multi-stage optimization problems. Its applications to transmission expansion [54-56] are given in Appendix 11.

In the dynamic programming approach, a set of network configurations are generated for each year or stage. Only feasible states, that is, those satisfying all specified constraints, will be kept

while all infeasible states are rejected. In this feasibility check, the network could be represented by the more accurate ac load flow model or the simpler dc load flow model. The operating cost, if any, for each state is then computed. A sequence of states, one at each stage, represents an expansion plan. Only expansion plans with feasible transitions from one stage to the next are considered. The problem is to find the sequence with the minimum cost.

Given the specified set of system states for each stage, DP is an efficient method for finding the optimal expansion. The crux of the problem then is to find a way of limiting the number of states (network configurations) so as to make the application of such techniques feasible for large scale systems. As with integer programming, limiting the configuration options almost always means that optimality is no longer assured. Since the dimensions of the problem are exponential with system size, it follows that the potential infringement on optimality will tend to increase with system size. The main problem area in through-time optimization is then the logic (typically heuristic logic) required to limit the number of configurations to be considered at each stage. The possibilities for improvements in this area are many.

5.3 Heuristic Planning Models

Throughout the discussion of optimization programs, there has been one underlying lamenting thought: That such drastic approximations need to be introduced to both system representation and objective function in order to produce transmission expansion plans with reasonable computer resources.

Meckiff, Boardman, Richards, and Green [57] state this concern and suggest a shift in emphasis towards heuristic planning programs.

It is somewhat surprising that so much effort has been given to devising mathematical methods for network design, but only a relatively small amount of effort has been devoted to heuristic methods. It is inevitable in a problem of such complexity that approximations must be made in the problem formulation. Many constraints which occur in real-life situations cannot be specified in absolute terms, e.g., considerations such as aesthetic appeal and acceptability to conservationists are unquantifiable. Therefore, any mathematically produced result can rarely claim to be a true global optimum. Any network design, suggested by whatever means, must come under close scrutiny after the computer has performed its function in order to assess its acceptability.

A review of proposed heuristic approaches with additional quotes from Reference 57 is presented in Appendix 12. Some of these approaches

attempt to simulate the way a planner uses existing analytical tools such as load flows [58,59] and reliability analysis [59] including simulations of the planning action through automated decision logic. Other approaches such as Garver's [47] method described in Section 5.1 combines heuristic logic for circuit selection with optimization techniques. Perhaps the ultimate in heuristic procedures are program systems that do not attempt to simulate the planner's decision but emphasize ease of communication between computer and user: that is interactive planning. In such programs, the planner would observe the expansion process and guide its direction to the extent desired.

6.0 STATE OF THE ART CONCLUSIONS

The state of the art of transmission planning tools may be summarized as follows:

1. Current Applications

Currently, only deterministic tools including load flow and dynamic simulation play a significant role in the actual planning of large scale transmission systems. However, probabilistic reliability analysis is being explored by several utilities in the U.S. as well as in Europe. Several automated expansion programs have been developed, but applications to date with such methods have been limited.

2. Load Flow Programs

Using the full Newton or the decoupled Newton methods, single ac load flow solutions for systems of several thousand buses can now be obtained rapidly on medium-sized computers. Algorithmic development has progressed to the point where the requirement of computational efficiency has been largely satisfied and where the emphasis on improvements has been transferred to user-computer interaction. In newer program designs, the abilities to rapidly change case specifications, obtain a new solution and look at particular results have become of major importance. These needs have led to the development of interactive load flow programs.

Future work in the load flow program area will probably concentrate on providing 1) better interactive features for single case computations and 2) faster algorithms for use in automatic contingency analysis.

3. Dynamic Simulation Program

The more advanced dynamic simulation programs have the capability of detailed machine representation combined with a capability of solving large networks.

For planning purposes, as opposed to detailed design considerations, the need for improvement in speed of execution and input/output handling, rather than in more detailed representation.

4. Reliability Assessment

At present, most planning procedures employ deterministic contingency or disturbance criteria for both security (dynamic) and adequacy (static) assessment. Load flow and stability programs are used to verify that a system meets the defined criteria. However, it is not clear that deterministic criteria assure reliable system performance and whether alternative system configurations which are designed to meet these criteria result in equally reliable performance.

Probabilistic procedures based on automatic contingency analysis or Monte Carlo techniques are capable of computing probabilistic reliability measures of system adequacy. However, simplifications are presently required in network models. Progress in this area is dependent on improvement in computer hardware/software for increased speed of network solution. More work is needed on the definition of system failure and on the formation of reliability indices useful for planning and design. In the near term a most useful application of probabilistic reliability computations appears to be to evaluate and sharpen the deterministic criteria presently used to assure reliable transmission systems. There are presently no tools that are capable of predicting security (dynamic) indices for large scale systems.

The reliability criteria themselves need to be reviewed through quantitative evaluation of the worth of reliability to the end user.

5. Transmission System Expansion Models

The gradient search, linear programming and integer programming approaches to single stage optimization each have their strengths and weaknesses. A general problem with all such models is that both the system representation and the expansion objectives are, of necessity, much simplified and do not cover the range of concerns a planner may have. Beyond that, the gradient search method has problems with local minima of the performance index, the representation used in the linear programming model may be too crude for many systems, and the present integer programming schemes may not be practical for large scale systems.

The basic problem inherent in any single stage expansion process is that it does not consider the timing of installations. Through-time optimization algorithms capable of including inflation and interest rates as well as year by year operating costs have been proposed based on both Integer Programming and Dynamic Programming approaches. For large scale systems, Dynamic Programming using heuristic logic to limit the network configuration alternatives appears to be the preferred choice. However, through-time optimization algorithms are obviously even further away from successful application than are single stage optimization models.

Considering the complexity of the transmission expansion problem and the simplifications that are often required to fit the problem to the optimization techniques used, it is possible that such techniques will prove to be a blind alley. Heuristic planning approaches stand out as an alternative, but as of yet, little effort has been spent to develop such techniques.

7.0 RECOMMENDATIONS FOR RESEARCH TOPICS

A systematic effort towards the improvement of tools for transmission system planning may logically follow the steps in Figure 7-1.

FIGURE 7-1

SYSTEMATIC PROCESS OF IMPROVEMENT OF PLANNING TOOLS

In reality, of course, advances in the state of the art are not so orderly. Progress may be initiated as shown by the need for handling new planning criteria, but it may just as well be initiated by algorithmic development which facilitates new approaches to the planning problem. In the latter case there may be a need for redefinition or expansion of planning criteria.

A multitude of organizations and individuals both inside and outside the electric utility industry do promote and advance the state of the art based on their varied backgrounds and incentives. Due to this diverse competitive environment there are normally several different competing approaches to the solution of a particular problem. Over a period of time one or more of these approaches will prove superior and the remainder will gradually be phased out. The development of load flow algorithms is a prime example.

In directing and funding research, one needs to recognize the importance of this ongoing development process and identify work areas that appear to have a high pay-off potential but that for some

reason or another have not been pursued vigorously. On this basis, the following list of research topics should be prime candidates for funding by the Department of Energy.

Research Topic #1:

Determine the effect of alternative deterministic planning criteria on system reliability and system cost.

Research Topic #2:

Forecast the potential improvements in system effectiveness that could be obtained if transmission systems were planned according to probabilistic reliability criteria.

Research Topic #3:

EXPLORE methodologies for probabilistic reliability assessment and assess the need for improvements or increased detail in the representation of network models, outage probability models, remedial action strategies and service interruption models.

Research Topic #4:

Explore the limitations of optimization techniques in large scale transmission system planning and determine in which subproblems such techniques can be expected to play a useful role.

Research Topic #5:

Explore the use of Monte Carlo simulation and determine for which subproblems these techniques may be potentially useful to U.S. planners.

Research Topic #6:

Encourage the development of innovative approaches to network, remedial action and service interruption solution algorithms. High speed, approximate solutions may be a particularly fruitful field of research.

Research Topic #7:

Continue research work on system effectiveness analysis.

The future direction of any of the five areas listed in Figure 7-1 will evolve from experiences gained by utilities in trying out the various planning approaches available to them. Research sponsored by the Department of Energy can enhance this evolutionary process by making available authoritative evaluations of existing and prospective planning methods.

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SECTION 6.

ENERGY SUPPLY/DEMAND MODELS

Four contractors researched this area. In all, fourteen models were selected. Only three of the models were selected by as many as three contractors. One model, SRI-GULF, drew the attention of all four. This group developed strong criteria for model selection. As a result some models with a regional basis which may be useful to researchers were not analyzed. Some might have interesting features. Two such models are: REAP, the North Dakota Regional and Environmental Assessment Program, Central Data Processing Center, Bismark, North Dakota and READ, the Regional Energy Activity and Demand Model, DOE. READ interfaces with a MRMI, the Multi-Region Multi-Industry Forecast Model by Frank Hopkins, William Donnelly, and Arthur Hanenner. The strong selection criteria does give a firm basis for the research needs conclusion of the report. The following is a summary of the contrasting approaches of the four contractors. The summary is followed by the analysis report of each contractor. Each contractor presents a detailed summary of the models reviewed for the convenience of researchers interested in developing new models. These details are in the appendices of the report.

The Montana Energy and MHD Research Development Institute report selected eight models for review. First basic areas of application, load forecasting, policy analysis, generation fuels, and technology assessment are identified. The usefulness of the models is based on these application areas. They clearly state their criteria for selecting a model to be analyzed. The models are compared by function and modeling techniques used. The analysis of research needs then follows from the application needs and the content of the models as shown in tabular comparisons.

The Center for Energy Studies, University of Texas at Austin report selects six models for review. Their approach is to compare the general features of the models in terms of scope, time frame, modeling technique, regional articulation, etc. They then formulate six policy questions and by analyzing the detailed characteristics of the models they determine the state of the art based on the models ability to respond to these varied policy questions.

The System Control, Inc., selected six models for investigation. These models were evaluated in terms of their meeting requirements appropriate for power system planning which are categorized by SCI as economic factors, demand modeling, new technologies, fuel competition, resource utilization, con-

servation, load management and environmental factors. SCI found BESOM and DESOM, a dynamic version, to be inappropriate for regional power system planning because they model the U.S. as a whole. SCI found the WISE model limited in terms of end-use substitution or changes in demand, but useful in estimating consumption and environmental impacts given growth and usage rates. They found the H-J model unsuitable for regional power system planning, per se, but of special value for policy studies that would influence power system planning. The SRI-GULF model was found to be of value to power system planners for forecasting future prices and quantities of fuels by region; however, the specification for electrical demand, electric generation, transmission and distribution investment, and electric rates was found not to reflect current utility practices. SCI found the REM model, which is a regionalized model explicitly designed to study the electric energy sector, suitable for regional power system planning. SCI found the Bechtel model to be a useful check of planning projections for resource or scheduling inconsistencies.

Data Resources, Inc. selected five models. DRI evaluated these models in terms of their regional scope, demand sector definition, supply sector definition, price estimation, applicability to electric utilities, and ease of use.

SECTION 6.1

THE APPLICATION OF ENERGY SUPPLY/DEMAND MODELS TO REGIONAL POWER SYSTEM PLANNING

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ABSTRACT

This report investigates that applicability of existing energy supply/demand models to regional power system planning problems. Criteria for evaluating models are established and six models are evaluated. The six models are (1) Brookhaven National Laboratory Energy Optimization Model (BESOM), (2) Wisconsin Regional Energy Model (WISE), (3) Hudson-Jorgenson Energy/Economy Model, (4) SRI National Energy Model, (5) Regionalized Electricity Model, and (6) Bechtel Energy Supply Planning Model. All the models can contribute some useful information to regional planning, but none is specifically designed to study regional power system planning. The need for a hierarchy of consistent planning models is identified.

INTRODUCTION

A year ago, the Electric Energy Systems Division of the U.S. Department of Energy (DOE; at that time ERDA), commissioned a study under the direction of the University of Oklahoma, to investigate the applicability of existing models to the problems of regional planning for electric power systems. Four separate areas of investigations were identified:

1. Supply/Demand Models
2. Generation Planning
3. Transmission Planning
4. Systems and Processes

This report is concerned with the applicability of energy/demand models to regional planning for electric power systems.

Study Objectives and Approach

The general objectives of the project, covering all planning models, not just energy models, are listed below.

- Define problem areas of electric utility expansion planning that logically should be addressed at the regional level.
- Determine state-of-the-art of models available to address these problems, including:

- Sources of data
- Techniques used in addressing these problems

- Determine what, if anything, new is required for regional planning

The primary objective of this study has been to perform a comparative analysis of several energy supply/demand models with respect to their capability to determine information useful to the regional power system planning process. The approach taken has been to examine a variety of different types of models to give the power system planner an overview of the variety of energy models that have been developed and how they relate to power systems.

In general, the questions to be addressed are:

- What are the necessary features of a regional electric utility planning model?
- Are existing models able to address issues relevant to regional planning?

Models Studied

In order to study the nation's complex energy issues, there has been a tremendous surge in the development of energy models - ranging from models of a single primary fuel industry, such as coal or petroleum, to models of the entire economy in which energy is just one sector. In their geographical coverage, the models range from single regions to the entire world. Some are dynamic and some are static. A great variety of methodologies have been used - linear programming, econometrics, engineering process, and system dynamics, to name a few. These models were created to study a variety of problems - ranging from engineering analysis of specific new technologies to the analysis of general U.S. economic energy policy.

For this study six models were selected for evaluation because each is a notable example of a particular type of energy model. Each sheds light on some particular aspect of the energy problem and each has its particular strengths and limitations. The models studied are listed below, along with a brief description of each model, to help the reader place the model within the hierarchy of energy models.

Brookhaven National Laboratory Energy Models (BESOM, DESOM) - National level linear programming models of the U.S. energy system with fixed demand.

Wisconsin Regional Energy Model (WISE) - State level simulation model of energy supply and demand subregions.

Hudson-Jorgenson Model - National level econometric model, relates energy consumption to the general economy, regionalized.

SRI National Energy Model - National level, partial equilibrium model of the U.S. energy system, regionalized.

Regionalized Electric Model (REM) - National level simulation model of the U.S. electric energy sector for electricity, regionalized.

Bechtel Energy Supply Planning Model - National level, energy supply simulation, regionalized.

The major attributes that characterize energy models are listed below. Each of the models studied is described in Appendices A through F.

MODEL CHARACTERISTICS

Purpose and Scope

Methodology

- LP, NLP, DP, I/O Econometric, System Dynamics, Engineering/Process
- Prescriptive, Descriptive

Level of Detail

- Spatial : World, U.S. Region, Single Utility
- Time : Long-Term, Short-Term, Static, Dynamic
- Technical : Entire Economy, Energy Sector, Electric

Supply

- Fuel : Price, Availability, Transportation
- Generation : Types, Expansion, New Technology, Reserve
- Endogenous/Exogenous

Demand

- Endogenous/Exogenous
- End-Use Substitutability
- Classes of Demand
- Energy or Peak Demand
- Variation of Demand (Seasonal, Daily, etc.)

Institutional Factors

- Interties
- Reliability
- Ownership
- Regulations
- Planning

Financial Factors

- Source and Availability of Capital
- Cost of Capital
- Utility Financial Model? Capital Accumulation?

Other Resources (Type, Availability, Cost)

- Labor
- Materials
- Water

Environmental Factors

- Siting
- Effluents
- Health and Safety

Consistency, Limitations

The body of the report is concerned with the application of energy supply/demand models to regional power system planning. In Section II evaluation criteria are developed and discussed. Section III presents an evaluation of the models with respect to the power system applications. Section IV identifies areas that require further research in terms of application to regional planning for power systems.

CRITERIA FOR EVALUATION ENERGY

MODELS WITH RESPECT TO REGIONAL

POWER SYSTEM PLANNING

The major purpose of this study is to evaluate the applicability of energy supply/demand models to regional power system planning. Regional power system planning is a broad topic; before any evaluation can take place, a set of possible applications of energy models must be developed, and criteria relevant to these applications must be established. This section begins with a general characterization of energy models, proceeds to discuss potential uses of energy models for power system planning, and concludes with a discussion of criteria relevant to these applications.

CHARACTERIZATION OF ENERGY MODELS

All models are designed to perform a function - to supply answers to or significant insights into questions of interest to the model designer; yet it is clear that all models, of necessity, are limited both in scope and the level of detail at which they address their subject. It is not a sufficient evaluation of a

model to say it is not perfect, for no model is perfect. Instead a model must be tested against each of its potential applications: if it can give useful information at a reasonable cost, then it is a useful model.

The first and most obvious questions about any model being considered for a particular application are these:

- Is the type of model appropriate to the function?
- Are all the important phenomena and processes included?
- Is the level of detail sufficient for the application?

One of the traditional ways of classifying models is as prescriptive or descriptive. If a model is intended to evaluate the consequences of a specified policy or plan, then it is called descriptive, predictive or positive. If a model is intended to determine optimal plans or policies according to some specified criteria, then it can be classified as a prescriptive, or normative model. In practice, however, this distinction is often rather artificial; the two procedures are equivalent under some circumstances. For example, models that operate on an optimization principle, such as linear programming models, are usually classified as prescriptive, but they may be, and often are, predictive. Also, complex models often have components of both descriptive or prescriptive models.

The degree of aggregation is a key element in the evaluation of models. There are three kinds of aggregation to be considered with respect to energy models: spatial (geographical boundaries), sectional (process/economic boundaries) and temporal. There are two basic questions with respect to aggregation in each of the above categories: at what level of detail does the model represent the dimension? And, does the model extend in this dimension? Thus, with respect to the spatial dimension, the questions are: what area does the model represent? The world, a country, a region, or a state? Secondly, does the model represent its area by a point value, that is, as a single homogeneous region, or does it have subregions? With respect to sectional aggregation, the questions are: is the energy sector just a part of a larger model of the entire economy? Or, does the model represent only the energy sector, or even some particular subsector, such as the electric energy component? With respect to time, the questions are: is the model static (a single point in time) or dynamic? If the model is dynamic, what is the period of study and what is the resolution, i.e., step size?

Structurally, most models identified as "energy" models are a combination of economic and physical relationships. Some of the techniques that have received wide application in

energy modeling are econometrics, linear programming, engineering/process, and system dynamics. Often the supply side and the demand side are formulated differently. Just as the prescriptive/descriptive distinction is often blurred, so it is with structural types - one type blends into the next, and models often combine types.

MODELING REQUIREMENTS FOR ELECTRIC UTILITY SECTOR

Two central factors in the modeling of the generation and use of electricity are load representation and generation mix. Since these two factors are so important to many of the potential uses related to the electric utility sector, they are discussed in general here, without reference to any particular application.

Because electricity cannot be conveniently and economically stored (as yet), the timing of its use is as important as the quantity used. Electric load as a function of time has a number of characteristic cycles as well as substantial random variation. Principally, there are daily, weekly, seasonal and annual cycles, each of which affects the generation requirements of a utility. Any study of electric energy that hopes to address new generation technologies, fuel competition, conservation or load management must model at least the primary time-dependent features of the load.

Load can be specified as a function of time but it is more common to summarize the time dependence of demand in the form of load duration curves. These curves are calculated for any period of interest (day, week, month, year); they specify the fraction of that period that the load exceeds a given level. Thus, the minimum load corresponds to 100 percent of the period, and the maximum load corresponds to zero percent of the period. The level of demand may be expressed in units of power or may be normalized by dividing by the peak power so that the maximum value is unity. The time is most commonly given in hours/period, but is also occasionally normalized. A typical annual load duration curve (LDC) is shown in the top of Figure 1.

The other universal feature of electric energy generation is the generation mix. Because capital costs and operating costs differ for different types of generating units, the economic choice of generating unit varies with operating circumstances. The cost of generation has two components, one proportional to demand (power, kW), the other proportional to energy used (kWh). The demand component is the annualized capital cost which must be paid no matter how much, or how little the unit is used per year. The portion of the generation cost proportional to energy consumed is primarily operating and maintenance expense and fuel cost. Units that have relatively high capital cost and relatively low operating costs are most economical to use in meeting continuous or almost continuous (base load) demand. Such units are

Figure 1. Load Duration Curve and Generation Cost Curve

usually denoted as base load generation units. At the other extreme, units with relatively low capital cost and high operating cost, are more economical to use to meet short duration, intermittent (peak load) demand. Units with intermediate costs meet intermediate demand. The generation cost per unit of power for each type of unit is a linear function of the number of hours per year that it is operated. The bottom half of Figure 1 shows typical generation cost curves for base, intermediate and peak load generators. From the figure, it is clear that the cost breakeven point between two generation units corresponds to the intersection of their cost curves. When these points are projected onto the load duration curve, the generation capacity in each category giving the least total cost is determined.

These two types of data, load duration and generation cost, are the primary determinant of generation mix. It is therefore crucial to electric system planning that they be well modeled. There are many complicating factors, such as geographic variation of fuel costs, and the fact that peaking units are normally used to meet rapidly varying daily peaks even when the total demand is not in the "peak" region of the annual LDC. Nevertheless, this type of "screening curve" analysis is widely used and is a very useful first order approximation.

APPLICABILITY OF ENERGY MODELS TO POWER SYSTEM PLANNING

Most of the problems relevant to regional level planning of power systems are really just power system planning problems considered at the regional level. Topics such as generation expansion, the incorporation of new generation technologies into the system, reserve margin and reliability and utilization of scarce resources are important at every level of system planning, including the regional level.

Energy models can be applied to many problems of interest to regional system planning. Some examples are given below, along with a brief list of factors associated with each application. The list is not exhaustive, but is representative of the type of applications that could be considered.

Economic Factors

Economic factors pervade energy analysis and may be considered on many levels, ranging from an engineering cost analysis to fully integrated energy-economic models which model the economic relationships between the energy system and the general economic system. Perhaps the most fundamental economic aspect of energy system models is the way in which supply and demand are modeled. Some energy models emphasize the supply-side while others emphasize the demand-side. Some model a particular market - such as petroleum - in detail, and some model the total system in an aggregated form.

Some models interact with the general economy and others consider only the energy market.

With respect to electric utilities, some of the more important economic factors at the regional level are:

- The effect of centralized regional planning on reserve requirements
- The price and availability of the various fuels as functions of time
- The capital and operating costs of the generation and supply of electricity as functions of time
- The average and marginal cost of electricity
- The price elasticity of demand for electricity for each end-use demand
- The degree of disaggregation of end-use demand
- The degree of availability of capital, labor and materials to construct the electric energy supply system

Demand Modeling

The modeling of individual end-use demands can be important in regional level analysis. One prominent example would be modeling the use of the electric automobile as a major element of the national transportation system. Such an event would have a major effect on the total electricity demand, the shape of electricity demand curves, as well as a tremendous impact on the regional demand for and price of gasoline.

New Technologies

Factors relating to the adoption of new technologies, either in the production of electricity or in industries that impact on the electric utility industry, are of great interest to planners. Factors that will be of importance in regional planning are:

- When will the technology become competitive?
- How rapidly will it penetrate the market?
- Which old technologies will be displaced?
- What will be the effect on the cost of electricity production?

It is always difficult to model a new technology. The real costs and efficiencies are difficult to estimate accurately until the processes have been actually implemented. Penetration rates are also difficult to estimate

since they obviously cannot be estimated from historical data. If an optimization procedure is used, the new technology will generally be used to its maximum level, or not at all depending upon whether or not it is lower in cost than an existing option. In order to circumvent this difficulty, the maximum penetration rate is often specified; however, this procedure is somewhat arbitrary. It can be at least partially justified on the basis of historical penetration rates of similar (if such exist) new technologies.

If the new technology to be studied is already developed and expected to be competitive in the near future, then it is desirable to model the process in some detail and probably with a predictive model so that detailed comparisons with alternative processes can be made. If, on the other hand, the new technology is only in the first conceptual stages, and a long-term research and development procedure is expected, then a simpler process model is appropriate, with cost and process characteristics specified parametrically, so that the cost-efficiency required for the process to be competitive can be estimated. A prescriptive model may well be most satisfactory for this evaluation.

Fuel Competition

Fuel competition has two aspects: the competition among fuels for energy production roles, and the competition of uses for particular fuels. Among the factors of interest are the following:

- Degree of substitutability
- Effect of specific fuel limitations
- Effect of changes in fuel prices
- Price at which various synthetic fuels become competitive
- How fluctuations of demand in related industries affect the electric utility industry
- Impact of new technologies on fuel demand

In order to model fuel competition, a model must have a mechanism to allow fuels to be substituted for one another. Alternative supplies for end-uses and a means of choosing among them allow the effects of fuel shortages, or changes in price to be studied. Supply functions for the various fuels range from constant price, infinite elasticity to sophisticated econometric relationships. Another important aspect of fuel competition is the effect of demands for other than energy uses of the basic fuels. For example, the steel industry uses much of the coal presently produced in the U.S., hence, perturbations in the steel industry cause a corresponding perturbation in the supply and price of coal.

Coordination of Resource Utilization

Resources other than fuels are also becoming scarce: plant locations, cooling water supplies and so forth. One of the advantages of regional power system planning would be the coordinated use of such scarce resources. This would result in more efficient use of these resources, both because of increased efficiency of facilities, but also because of increased efficiency in the use of facilities.

To study these effects, a model must explicitly consider such factors as available plant locations, available cooling water, and fuel transportation limitation.

Conservation of Scarce Resources

Conservation is being recognized as an important factor in meeting the future energy needs of the U.S. It could be a major factor affecting future electric energy demands, and must therefore be a factor in regional power system planning. In order to evaluate various strategies, their impact on the demand for electricity and other energy forms must be estimated. There are three broad classes of energy conservation:

- Reduction in demand, either voluntary or price induced.
- Increased efficiency in production, transmission and end-use
- Substitution of plentiful resources for scarce ones

In order to model conservation of electricity, a model should allow for the convenient representation and alteration of these three factors. In modeling reduced end use, the timing as well as the magnitude of the reduction is important. It is important that not only the reduction in energy use be calculated, but also the effect on the shape of the load duration curve, so that the impact on generation mix and generation cost can also be estimated.

Load Management

Load management can be defined as any action undertaken for the purpose of influencing the magnitude and timing of the electric load. This includes such diverse procedures as:

- Energy storage devices
- Pricing policies
- Central control of electrical devices such as water heaters or air conditioning units

To evaluate central storage devices, it is sufficient to model system LDC and generation cost. However to evaluate the effect of pricing policy on consumer habits requires a model of consumer response.

Environmental Factors

The evaluation of regional environmental impacts has become in recent years, an important aspect of every substantial project. The effect of alternative energy supply systems on environmental impacts is a key evaluation feature. It is essential to look at:

- Environmental damage functions
- Process pollutants
- The cost of mitigating environmental impacts

Many of the processes involved in energy production have significant regional environmental impacts. Thus, in the evaluation of environmental factors is an important component of energy analysis. There are two aspects of every environmental problem: the kinds of mitigation measures and the degree to which they can be taken to alleviate the environmental impacts. It is very useful to associate costs with each of the aspects so that reasonable cost tradeoffs can be made. The costs of mitigation measures are normally easier to estimate than are environmental damage costs, since it is not easy to anticipate all the potential environmental impacts of a newly developing technology.

With respect to power systems, environmental problems can be subdivided into two broad classifications: those associated with the supply of fuels (such as the strip mining of coal and the disposal of nuclear wastes); and those that are site specific, such as air and water pollution associated with particular generation facilities. In order to evaluate the environmental impacts of generation units of a given type, not only must the kind and degree of direct effect be known (for example, the amounts of specific effluents), but the ambient environmental conditions must also be known, as well as the nature of other sources of pollutants in the same area.

SUMMARY

No model can be expected to serve all applications equally well. It is particularly unfair to expect a model to perform tasks other than the ones it was designed for. Yet the demand for electricity and other energy forms is integrated into our society so pervasively and extensively, that energy questions impact on almost all of society's activities. It is only natural that energy models are often called upon to perform functions other than those for which they were originally created. It is therefore critical to understand the capabilities and limitations of a model with respect to the application at hand before using the model and interpreting the results.

EVALUATION OF MODELS

In this section the six energy models are evaluated with respect to their applicability to

analyses relevant to regional power system planning. The evaluation consists of two parts: a discussion of the models' general capabilities and limitations, followed by a discussion of the models' potential for regional power system applications.

BESOM AND DESOM

BESOM and DESOM are linear programming (LP) models of the U.S. energy system. BESOM is static, it models a single year (1985 or 2000). DESOM is a dynamic version of BESOM, related by a series of additional constraints. Both models were developed as national level models, although they could be made to represent a region if appropriate regional data are used. (In fact, BNL is developing a version of BESOM for the TVA region.)

The models place considerable emphasis on the supply and use of electric energy. There are eleven explicit central generation technologies modeled. Electric energy storage is modeled in the form of pumped hydro and the creation of hydrogen by electrolysis. The use of fossil fuels in fuel cells is considered. Solar energy is allowed for decentralized uses.

One of the fundamental properties of LPs follows from their basic linear character: if one variable is superior to another, the superior variable will be used exclusively instead of the inferior variable, no matter how slight the superiority, unless it is constrained. This makes mathematical sense and also physical sense, if the processes modeled are truly linear. The problem is that the energy supply system is nonlinear.

In BESOM, solutions are controlled by placing constraints on variables so that they are forced to satisfy "reasonable" conditions imposed by the user. Such a procedure places the user in a dilemma, however for the more the model is constrained, the more rigid the model becomes, and the greater the reliance on experienced users. For example, the use of natural gas in the BNL models is constrained for each of its possible end-uses. The constraints are so tight that they are virtually an exogenous allocation of the natural gas supply. Another interesting example is the way in which space heating and air conditioning is met by electricity because there is no effective alternative. The seasonal-peak constraint relations require that at least a specified fraction of space heating needs be met by electricity. This corresponds to reality, so that one might feel that the model has done well, but in fact, the mechanism used in the model bears little relationship to the real reasons why some space heating is done electrically.

Although DESOM is called the "dynamic" version of BESOM, it is dynamic only in a very limited sense. The supplies, demands, and prices are all prespecified. The system optimization is per-

formed over all time simultaneously, so that the optimum solution for the entire time period is obtained. This is not a flaw in the formulation, it is merely a fact that must be recognized. Thus, DESOM cannot be "surprised" by abrupt changes in demands or prices in some future year, it determined the optimal allocation for all years with full knowledge of future prices and demands.

Degree of Aggregation

The fact that BESOM and DESOM are nationally aggregated detracts from their ability to accurately model the electric energy subsystem. There are very substantial differences among regions with respect to the availability and cost of different fuels. The shape of the electric load also varies a great deal from region to region. Some electric utilities have their peak load in the summer and some have their peak load in the winter. Regions with hot summers will experience much greater air conditioning loads than will regions with moderate summers. Some regions, such as the northwest, have a great deal of hydroelectric power which yields low cost electric energy.

As a result of these and other regional differences, the competition among the sources of electric energy as well as the competition between electric energy and other energy sources is quite different in different regions. Because of their national level of aggregation, BESOM and DESOM cannot effectively capture these important regional effects.

Electric Load Model

The total electric load in BESOM and DESOM is modeled as the sum of the electric portions of the individual end-use annual energy consumption. The time dependent nature of the loads is approximated by associating a two-step load duration curve (LDC) with each end-use. This procedure is superior to merely modeling the energy demanded by each end-use, but it is still seriously limited.

The electric load is modeled as a single national load which is, in effect, satisfied by a single group of electric power generation units. But there is no such thing as a total national electric load - there are a large number of individual loads with different daily, weekly, monthly, and yearly characteristics. The sum of these loads will have an LDC that is less peaked than the sum of the corresponding LDCs, since there is considerable diversity among the loads. On the other hand, since the load is modeled as the sum of component LDCs, there is a countervailing tendency toward an LDC that is too peaked. It is impossible to say which of these countervailing influences prevails without making an extensive investigation of electric load characteristics, but it is certain that the models have seriously short-circuited reality.

The concept of keeping the end-use components of the electric load separate is an excellent one.

It makes possible the tradeoffs among end-uses.

Specific Applications

In this section, BESOM and DESOM are analyzed with respect to specific electric utility planning applications. The appropriateness of the models to the application is evaluated and specific strengths and weaknesses are delineated.

New Technology

As the development costs of new technologies and perhaps even more importantly, the competition for R&D funding, have increased over the last two decades, it has become essential to assess the potential value of new technologies. This is one of the applications of models like BESOM and DESOM - to estimate when (or if), a new technology will become competitive, what its penetration rate will be, and which technologies will be replaced.

BESOM and DESOM do provide some information of this type. Because of its static nature, BESOM cannot provide much information on questions of timing, such as penetration rate. It does tell whether or not a technology is competitive at the time of the year being analyzed. Also, if it does not enter the solution, its shadow price provides an estimate of how much its price would have to decrease in order for it to enter the solution. However, the models are limited in this capacity by their lack of regional detail.

Because of its time dimension, DESOM can provide some information on when a new technology will become competitive and how fast it will penetrate the market. However, maximum growth rates are specified for DESOM technologies, so that, once a technology becomes cost competitive, it tends to grow at its maximum allowed rate. For example, in one DESOM run evaluated, the LWR, LMFBR, and coal steam technologies were all growing at their maximum allowable rate. Such scenarios are obviously very dependent on the exogenously specified growth rates, thus, one almost has to have the information sought before the run can be made.

Fuel Competition

BESOM and DESOM are capable of modeling fuel competition at its most fundamental level because the demand for energy is broken out into end-use categories such as space heating, water heating and air conditioning, rather than demand for specific energy forms or fuels, such as electricity or natural gas. This feature allows different energy forms to satisfy the same end-use and is one of the models' best features.

Fuel shortages can be simulated by imposing supply constraints on a selected fuel or process. The most obvious example of this effect in the model is the constraint on the

natural gas supply. At its specified price, natural gas is in great demand and would be used to a much greater extent if it were not constrained. Since the natural gas constraint is limiting, the corresponding shadow price gives an indication of relative values, but must be interpreted cautiously since the economic equilibrium of the model is so artificial. (Supply elasticity infinite, demand elasticity zero.)

The models also can (and do) model synthetic fuel manufacture and supply. As with all processes in the models, the synthetic fuel processes are represented physically by a single efficiency so that the models are not appropriate for doing a comparative analysis of two similar processes, for example two competitive coal gasification processes. However, the models can grossly represent an average synthetic fuel process, so that its integration into the total energy system can be evaluated.

Another important aspect of fuel competition is the competition of non-fuel uses for fuel resources, such as steel production from coal or fertilizer production from natural gas. These competitive demands have an important effect on the price and availability of basic fuels. However, these demands can only be modeled exogenously by BESOM and DESOM.

Conservation

BESOM and DESOM have no built-in mechanism that specifically model conservation, but certain conservation schemes could be simulated, at least partially, by adjusting end-use demands, altering the shape of the electric energy load duration curves, or changing the efficiency of some of the supply processes. Such analyses would supply some information on the sensitivity of the energy supply system to such measures; thus, the cost of the total energy supply could be compared to its value without the conservation measures. For example, the effect of increased insulation in residence could be simulated by increasing the cost of supplying space heat (to account for insulation costs), and reducing the demand correspondingly.

The difficulty is that the relationship between the amount of insulation and the reduction in heating requirement is fundamentally nonlinear. A linear approximation can be made, but the extra insulation will either be cost effective and the maximum amount allowed will be used, or it will be ineffective and none will be used. This difficulty can be partially resolved by modeling the nonlinear relationship by a staircase function, but this procedure requires the introduction of new variables and constraint equations, and hence, cannot be applied without structural modification of the program.

Other types of conservation techniques, such as price increases or tax increases, can be modeled only by exogenous adjustment to total

demand or through an iterative evaluation process in conjunction with an economic model.

Load Management

Management of the electric energy load is very similar to conservation in terms of modeling. Most load management techniques could be simulated by an exogenous adjustment to some or all of the electric load duration curves.

Environmental Effects

BESOM calculates the amount of polluting effluents and certain other adverse effects per unit of intermediate energy form produced by each process. These environmental effects can be divided into two categories: direct and indirect. Direct effects are those such as deaths, injuries, or man-days lost, which are meaningful when aggregated on a national basis. Indirect effects are those such as the amount of SO_2 or CO emitted, which are not meaningful when aggregated over the nation (or even large regions).

The total quantity of each effect is obtained by summing over all of the contributing processes. Each of these quantities can be constrained to be less than, or equal to, some national upper-bound. Whenever a constraint is binding, the corresponding shadow price gives the sensitivity of the total cost to the constraint. Thus, by adjusting the environmental constraints over a range of values, a cost sensitivity function can be developed.

Knowing the total amount of polluting effluents on a national basis tells us virtually nothing about air and water quality. Quantitative air and water quality predictions must be evaluated on a very local basis, and must consider ambient conditions and other sources of pollutants, which of course, BESOM does not, and can not consider.

BESOM could give comparative cost estimates of different environmental control strategies by comparing the total cost of meeting a specified set of environmental constraints utilizing several processes with varying mitigation technologies. For example, a number of SO_2 emission controls could be modeled (each with its characteristics cost). The system response to these controls could then be evaluated for several levels of constraint on total SO_2 . The user must be cautioned that such estimates are very approximate for the reasons discussed above.

DESOM has no environmental constraint equations.

Economic Analysis

In an economic sense, the models presume static equilibrium. They focus on the technical

rather than an economic view of the energy supply system. The supply elasticity is infinite, up to the supply upper-bound, at which point it becomes zero, whereas, the demand elasticity is zero. This is the simplest possible economic model, and as such, it cannot realistically model the energy market. There is no provision to deal with regulations, subsidies, controls or market regulating devices per se, although they can in some measure be simulated by adjustments in supply, demand or price or introduction of additional constraints. Since the electric energy market is highly regulated, it is important that a model be able to deal with this factor.

The larger economic issues - the relationship between GNP and energy, the degree of substitutability between labor and capital, the availability of capital and labor to meet the growing needs of the energy supply system cannot be studied within the context of BESOM and DESOM. To investigate these issues, it is necessary to employ models that deal with the economy as a whole.

Summary

BESOM and DESOM have a fairly extensive electric energy component but their representation of the U.S. as a single homogenous region makes them inappropriate for regional power system planning. The development of regional versions and the incorporation of a more detailed representation of the load duration curve would make these models more relevant to regional applications.

THE WISCONSIN REGIONAL ENERGY MODEL (WISE)

WISE is a simulation model of the supply of and demand for energy within the State of Wisconsin (or any other for which the appropriate data are collected). The collection of submodels which have been developed (and are still being developed) over a period of several years by a large number of individuals are classified into five categories:

- (1) External energy supplies and prices
- (2) Energy conversion and supply models
- (3) Socio-economic activity models
- (4) End-use energy demand models
- (5) Environmental impact models

Categories (1) and (2) comprise the supply side of the energy market; categories (3) and (4) comprise the demand side of the energy market.

Degree of Aggregation

WISE simulates the passage of time in one year steps. The case studies published simulate the 1970-2000 period, although no specific time limitation is mentioned. Presumably, if the necessary exogenous data were available it would be straightforward to extend the time frame.

Spatially, WISE was designed for the State of Wisconsin, which is disaggregated into its 72 counties. Energy consumption in each demand category is apportioned to each county in proportion to its current fraction of the total. For electric energy supply, however, the state is broken down into eight load density regions.

WISE models the entire energy sector but the supply side is essentially exogenous, except for electricity, since Wisconsin has no internal primary fuel supplies other than hydro, solar and wind. The demands are broken down into five major categories: residential, commercial, and government, industrial, agricultural and transportation. Each of these major categories is further disaggregated. Residential energy demand is broken down by residence type and appliance ownership profile. The commercial and government category is separated into a commercial demand and a government demand. In the industrial category the various types of manufacturers are defined according to the Standard Industrial Classification System (SIC). The two-digit level of disaggregation is used in WISE which defines 20 separate industrial classes. In addition, in the SIC categories most important in Wisconsin, three-, four-, and even five-digit data are used.

Primary Inputs and Outputs

The primary inputs to the model are the parameters that define the socio-economic activities: population migration, fertility, and mortality; initial values and trends in the economic activities of the state; time-dependent description of primary fuels, including origin, composition, energy content, price, and availability; and energy intensity of all energy using processes.

The primary outputs are time history of fuel consumption for each fuel plus the time history of the models' other activities.

Demand Submodel

The demand submodel is comprised of the socio-economic activity submodels and the end-use energy demand models. The socio-economic models predict population and level of economic activity for each county in the state. The population model used is the age-, sex- and county-specific model developed by the state demographers office. This projection is independent of other model activities. The levels of economic activity are estimated by exponential growth models. These models have no feedback from price or cross-correlation to other activities. This assumption of the continuation of present trends is certainly questionable. The model is undergoing continuing development and more sophisticated submodels are being developed for many activities.

Another problem with the demand models is that there is no mechanism for substitution of

the use of one energy form for another, even heat and light, rather than electricity and oil. The incorporation of a mechanism to alter the demand ratios as a function of relative price and other relevant factors would add greatly to the models credibility.

Supply Submodel

Since Wisconsin imports virtually all of its fossil and nuclear fuels, the dynamics of the supply of these fuels is not modeled. The model does keep track of quantities of the various fuels imported and models the storage and transportation system required to support the fuels imported.

The electric energy supply industry is modeled in some detail. The model consists of two major components: transmission and distribution, and generation capacity submodels.

The transmission and distribution submodel is described as using "either historical correlation between generation capacity and transmission requirements or hypothetical geometrical load-source patterns to forecast the transmission requirements..." Since no more information is given, it is not known how much detail is involved in the calculation of transmission requirements. Distribution cost has two components, one proportional to the number of new residential customers, and the other proportional to the increased energy density in commercial and industrial sectors.

The generation capacity submodel has three major functions:

- (1) To convert energy demands into capacity requirements,
- (2) To determine the most appropriate plants to satisfy the capacity needs beyond existing capacity
- (3) To calculate the associated, capital, operating and fuel costs.

Energy demand is converted to a capacity demand by dividing by the load factor (the normalized area under the load duration curve). The procedure for selecting capacity additions is based on an arbitrary designation of load categories. For example, the base-loaded capacity is specified as being on-line for a certain number of hours per year. This number of hours is translated through the LDC to define the base-load capacity. This procedure fixes the proportions of the units designated as base-load, intermediate, and peaking units. Furthermore, it takes no account of any relative shifts in generation costs that may occur as the result of changes in capital costs, O&M costs, or fuel costs.

The electricity supply costs are fed into a revenue-pricing model which computes the price of electricity. The details of this submodel are not specified. A mechanism for adjusting demand on the basis of the difference between the price

calculated and the initial price assumed is under development, but no details were given.

Applications

The model has been used to provide long-range forecasts of Wisconsin's energy consumption for a variety of scenarios, analysis of energy conservation in the form of more efficient air conditioners, a shift toward smaller automobiles and improved building insulation. The model has also been employed to analyze the impact of a natural gas shortage in Wisconsin.

WISE also has a number of environmental submodels which allow it to evaluate environmental impacts associated with the energy alternative studied. Environmental impacts are broadly defined to include effects on land, air, water, structures, and living things. Internal health and safety effects on the producers and users of energy are considered in addition to the external effects.

Summary

In its present form, WISE essentially projects the demand for energy assuming that present trends continue throughout the simulation period. Energy consumption and environmental impacts can be estimated for different assumptions about growth rates and usage rates, but the program has very little possibility for economic adjustment, in terms of end-use substitution or reduced demand in response to increased prices.

THE HUDSON-JORGENSEN MODEL

The Hudson-Jorgenson (H-J) model is a large macroeconomic growth model integrated with an input/output model of inter-industry transactions. It is very capable of handling policy issues and measuring their impact on aggregate levels of demand and supply, as well as the allocation among different uses of energy. Potential changes in energy consumption can be expressed in tons of coal, barrels of crude oil, cubic feet of natural gas (pipeline sales and gas utility sales), gallons of refined petroleum and kilowatt-hours of electricity.

The model is a general equilibrium model in the sense that the solutions are constrained to the quantity of goods and services supplied in all markets (through production and imports) with those demanded. For a territory with a wide variety of industries and a relatively low level of imports, the H-J model is a valuable tool. However, a reliability region such as ECAR, MAIN, or the Northeast Central region of the U.S. might not be autonomous in terms of production and consumption. Furthermore, even if a region was wide and deep in industrial and agricultural production, there is no guarantee that data exist on flows of goods and services.

As a policy instrument, the H-J model examines two states of nature. One before the policy in question is enacted, and another after

the policy is in effect. The time to adjustment and the cost incurred to make the adjustments are not considered. In short, the H-J model is in constant economic equilibrium; it models the time history of the equilibrium conditions, but does not model transient departures from the equilibrium. It analyzes the beginning and the end of a chain of events. This does not imply that the H-J model yields incorrect results. However, for purposes of regional planning, transient conditions and transaction costs of adjusting to long run equilibrium can be important.

The introduction of new technologies are assumed to be "neutral" in that the ratio of any two factor inputs remains unchanged as output expands. On a national level of aggregation the assumption might be acceptable. For a regional analysis, the flows of labor, capital, and materials and energy might certainly be affected as for example: (i) nuclear production of electricity replaces fossil, or (ii) production of synthetic natural gas and coal gasification are substituted for pipeline gas. The instance of these technologies in a region might impact the demand for labor and capital, and thus affect the relative wage rate and price of capital services for the entire region. The H-J model can not measure these inputs directly whereas regional planning models for electricity must be sensitive to the total economic effects of new technologies - especially energy technologies.

The H-J model does disaggregate industrial activity such that the production of electric utilities can be examined in physical flows (kWh) and revenues. The H-J model does not look at peak demand for electricity.

In conclusion, the H-J model is a very efficient policy analysis tool. It yields a long run steady state solution for a country or territory that produces and demands goods and services. The level of detail in the energy sector is sufficient for aggregate analysis of energy flows (further development of the H-J model has expanded the inter-industry input/output model to include production functions for fourteen energy flows, up from five in the original specification of the model), but is too broad for application to a region. Further, implementation of the H-J model on a region would require regional data and forecasts on items such as:

- Demands for goods and services by government;
- Amount of exports, net of imports;
- Inflation rate.

The H-J model is not a directly suitable tool for regional planning of electric power systems. However, the results of policy studies performed by the model would certainly be of interest to power system planners, and would influence regional planning.

SRI-GULF ENERGY MODEL

The SRI-Gulf Energy Model is a comprehensive model of the U.S. energy system from energy production, processing, transportation to end-use consumption. The model uses a process/engineering approach. First the linkages between processes in various regions are established by a network structure, then a set of physical flow relations and behavioral relations are formalized relating the energy capacities, prices and secondary materials between the linked processes. The model finally seeks a "generalized equilibrium" that satisfies all these relations over time. The model will be first evaluated with respect to its general characteristics. Its applicability to regional power system planning will then be discussed.

Use of Exogenous Parameters

The model includes a large number of exogenous parameters describing the behavioral relations over 2700 processes, including market share, technological change, behavioral lag, price sensitivity to mass capacity, secondary material cost adjustments, economic rent, and end-use demand elasticity, thermal efficiency, etc. One problem is that determination of most of the parameters is not based on statistical data, similar to the criticism often made of system dynamic simulations. Also many of the exogenous variables may not be able to estimate quantitatively because of the lack of data. For example, the "price" of the process of residential/commercial electricity distribution for space heat or that for non-space heat. The data used for end-use demand, such as demand for water heating/cooking/drying and space heat are generated exogenously, since no data has ever been collected. Only the source of the data for the initial energy balance can be verified.

Level of Detail

The model is claimed to be capable of modeling any level of detail required for analyzing any particular energy problem. However, addition or deletion of processes is very time-consuming in the present network structure. The linkages between newly added processes and every other related process in all regions must be explicitly constructed. All these must be manually and heuristically done, guessing which linkages are important enough to be constructed. It may turn out that many linkages may never be anywhere competitive, yet in order to delete any linkage to reduce computational time, one must return to first phase to re-structure the network. In short, since there is no systematic way of automatically adding or deleting processes and linkages, the model is very cumbersome to use.

Computational Requirements

The SRI-Gulf Energy Model, after the network structure is set up, requires 40 to 90

minutes of IBM 370/168 computing time for a nominal case beginning with fresh initial estimates of prices and quantities. Even for a case with minor changes in some of the parameters from the nominal setting, the model could take up to 40 minutes to run. It also requires 600,000 bytes of core storage. Therefore, the model is very expensive to run, which reduces the flexibility to run to large number of sensitivity cases.

Power System Planning

The rest of the model evaluation will focus on the applicability of the model for regional power system planning. In general, the results of projected future prices and quantities of fuels for different regions may be of aid to power system planners. However, there are features and assumptions in the model that may not accurately and adequately reflect current electric utility industry practices. These are discussed below.

Electrical Demand

The demand for electric energy is modeled in terms of the demand of the end-use of electrical energy in space heating, air conditioning, etc. The pattern of end-use demand is not related to load factors (i.e., capacity factors) of different load categories. However, they are in fact, related. For example, the increase of space heating requirement may increase the off-peak load and therefore change the load factors and the allocation of total electric demand into base load, cycling, or peaking use. The result is that changes in load curve due to changes in end-use demand is not explicitly included.

Electric Generation Planning and Operation

The SRI-Gulf Energy Model does not explicitly consider reserve requirement or reliability. It also does not include other important technological features such as maintenance and forced outage rates. It was suggested that the model can incorporate reserve requirement by adjusting the load factor (which should correctly be called capacity factor) or unit capital cost. In both cases, these would be exogenously set. However, if one plans to study the cost and benefit of regional power system planning, the model can only be used to analyze the effect of decreasing reserve requirements of electric generation on the rest of the energy systems, but not to analyze how the reserve requirement may be changed due to regional planning.

The utilization of different generation technologies is limited to one of the three discrete categories of base load, cycling, or peaking use defined by fixed capacity factors. In reality, a technology may be used with other capacity factors. In the model, this can be done by adding more categories at the expense of complicating the network structure and increasing the computational requirements.

The determination of generation capacity expansion is driven by a market share submodel, as described in Appendix D. The validity of using the particular form of market share equation and the exogenous parameters was never demonstrated.

Transmission and Distribution Expansion

The treatment of transmission and distribution (T&D) equipment is unconventional. In the model, T&D are classified as either industrial electricity distribution, residential/commercial electricity distribution (except space heat), and residential/commercial electricity distribution (for space heat). Regional and industry data are not available in these categories so that the data needed to support the above classification are derived using judgement. This is potentially a significant problem since T&D costs made up 1/2 to 2/3 of total electricity costs.

Transmission and distribution investment have been shown to be closely related to peak load and generating capacities rather than energy output. This model, however, relates T&D costs only to the energy output rather than the capacities of the generation conversion processes.

Electricity Rates

The model determines electricity prices based on the cost of additions of new generation, which is not the current practice. This marginal cost pricing method is different from the conventional revenue requirement or rate base pricing that determine user's charges, according to the revenue required to cover the annual charges of existing generating units. This could be incorporated in the model by reprogramming the pricing submodel.

The modeling of the electricity pricing behavior is, except for minor adjustments, exactly the same as any other profit making industry. This however, does not capture the characteristic that the electric utility industry is regulated.

REGIONALIZED ELECTRICITY MODEL (REM)

REM is an engineering-econometric-financial simulation model of the electric utility industry in the United States. The supply submodel is in the form of an engineering model, the demand submodel is econometric and the two are coupled by the price of electricity which is determined in the financial submodel. The model is spatially disaggregated into nine regions, although many of the calculations are performed at the state level. The model simulates a 50-year time period, from 1947 to 1997 in one-half year steps.

REM is a straight-forward simulation which steps forward through time in half-year steps.

Very little iteration is required (the solution of a transcendental equation to determine the optimal uranium fuelings assay requires interaction, but this is minor), thus the program should be fairly economical to operate. The program also appears to be easy to modify or extend.

Major Inputs and Outputs

The major outputs are the price and consumption of electric energy as a function of time. Other important quantities of interest are the number, type and vintage of generation plants, the demand for and sources of capital as a function of time, and the quantity of raw uranium fuel required, as a function of time.

The major inputs are prices and heat rates of fossil and nuclear fuels as a function of time, capital and operation and maintenance cost data for each of the generation plant alternatives.

Some of the key financial parameters are regulated rate of return on equity, debt ratio limit, investment tax credit rate, interest coverage ratio, interest rate on new debt issue, preferred stock dividend rate, and payout ratio. In addition, there are a number of financial policy variables to be selected. Preferred stock dividends can be expensed, the split between normalized and flow-through accounting can be set, and work-in-construction can be allowed in the rate base.

Supply Submodel

The supply model consists of an engineering/process model of nine generation technologies plus an empirical model of transmission and distribution. The generation technologies are described essentially by their cost curves which are a function of capital costs, O&M costs and fuel costs. In the case of the four fossil fuel technologies these curves are exogenously specified functions of time. There are no detailed process descriptions for fossil fuel generation. In the case of nuclear generation, the fuel supply and reprocessing processes are modeled in considerable detail since the price of fuels and the split between uranium and plutonium depends on the price of raw uranium, reprocessing capacity and a number of other factors. This allows the model to study nuclear fuel processing options with relative ease and fidelity. Hydro capacity is specified as an exogenous function of time, presumably because of its limited availability and because other factors, such as flood control and irrigation figure prominently in decisions regarding hydro.

The transmission and distribution submodel calculates T&D capital and operation and maintenance cost on the basis of empirical regressions. The main independent variables are annual energy consumption, area served, load

density and number and type of customers. This method was used to estimate T&D requirements because of the difficulty in determining T&D requirements on an analytical basis. The problem with empirical relationships of this sort is that they reflect the conditions that existed when the data was acquired. It is impossible to know how well they will reflect the conditions of the future.

Demand Submodel

The demand model is econometrically based. The demands for electricity and fossil fuels are estimated for two categories, industrial and residential and commercial. Fossil fuel prices are specified exogenously while the price of electricity is calculated endogenously. The demands for electricity, oil, natural gas, per capita income, population, population density and temperature extremes. These calculations are performed on a state-by-state basis and then accumulated for each region.

Annual load duration curves (LDC) are represented in the model by piecewise linear curves of 17 segments. This number of segments allows quite an accurate representation of the LDCs. A fixed shape for the LDC is assumed throughout; the LDC is scaled up or down to correspond changing usage factors (load factors). The usage factors for "current" are exogenously specified; those for the "current" planning horizons are forecasted using the simple trend forecasting technique which is used to represent utility practice.

The method of scaling used to adjust the LDC is reasonable but arbitrary. For regional planning purposes it would be very desirable to break down the demand into more categories and to consider their specific impacts on the shape of the LDC.

Financial Submodel

REM has a very detailed utility financial model. Each region is treated as though it were a single utility. The financial submodel completes the regional price of electricity by a process that simulates the regulatory process which actually sets electricity prices. It also keeps track of capital equipment through construction and calculates a number balance sheet and income statement items. It also makes financial decisions.

This submodel allows the user to explore a number of financing options that have been suggested as means to relieve the utilities capital shortage problems. It allows the "state power authority" to meet capital requirements that cannot be met through conventional means. This SPA financing is a measure of capital shortfall that is expected for the scenario being studied.

Applications

Since REM is a regionalized model explicitly designed to study the electric energy sector, it is quite suitable for studying many relevant electric power system problems. It has been used to perform a number of policy studies such as financial alternatives, load management alternatives, capital and fuel cost scenarios, nuclear fuel cost scenarios, the effect of a nuclear moratorium, and alternative demand growth scenarios.

It does not have the capability to analyze environmental impacts, since this would require more geographic detail than is currently modeled. However, the model can determine the impacts of increased capital, fuel and O&M costs which results from environmental control requirements.

The model does not consider any advanced technology options such as pumped hydro storage, fuel cells, or solar power generation. Adding these technologies would not be a trivial task since each of them effectively alters the shape of the LDC, which would have to be explicitly modeled.

Summary

REM is a well-balanced regionalized model of the U.S. electric energy sector. The model is primarily directed toward national electric energy policy analysis but still can provide information of interest at the regional level. The model could be made more useful at the regional level by disaggregating demand into more end-uses and by making the shape of the LDC depend on the specifics of the load components. However, it is recognized that the data to perform such modifications are difficult, if not impossible, to obtain.

THE BECHTEL ENERGY SUPPLY PLANNING MODEL*

The Bechtel Energy Supply Planning Model is designed to determine the resource requirements and scheduling requirements necessary to fulfill a twenty-year scenario of energy mixes (1975-1995). The intention was to develop a model that can be used to explore the feasibility and desirability of energy policies. This model is expressed primarily in physical units; there is no consideration given to overall monetary costs or fuel prices. No explicit optimization is conducted and no predetermined criterion is implemented to compare policies. The avoidance of economic considerations distinguish this system

* This discussion is based solely on the documentation of the model by the Bechtel project team, "the Energy Supply Planning Model," Volumes I and II, Bechtel Corporation, NTIS Report No. PB-245 382, August 1975.

from other established national energy models.

General Approach

The approach used in this model seems credible in the scope of its intended purpose. Assuming proper calibration, this system will readily indicate potential bottlenecks that would probably be neglected in evaluating energy policy objectives using other models or non-model planning strategies. The model outputs explicitly indicate when construction of facilities must be initiated and when these facilities must be on-line to attain the scenario under consideration. At this physical level, this methodology provides a very useful tool for assessing the feasibility of an energy program.

While the system addresses the U.S. at a national level, regional analysis is also accommodated. The disaggregation into regions appears to be plausible from the standpoint of transportation and resource data and is reasonably consistent with the regional disaggregation in other energy models. Further disaggregation to the state level could be accomplished under the existing structure.

Another important feature of this model is its attention to transportation requirements. Given proper initialization by the user, the system will generate the necessary facility and manpower capacities at either a national or regional level. Therefore, transportation is appropriately considered to be an integral part of the energy system for the purposes of policy feasibility.

This modeling system allows the user considerable flexibility in the specification of inputs and generation of outputs. The user can provide a national energy mix and regional coefficients or simply the national energy mix. Default inputs are provided for those parameters the user elects not to specify.* Depending on the level of analysts and degree of input specification, the model will generate: (1) national energy facility requirements and transportation facility requirements, (2) regional energy facility requirements and national transportation facility requirements, or (3) regional energy and transportation facility requirements. Therefore, the model will accommodate a very detailed analysis, but allows the user to avoid a level of detail that would be excessive for more general analyses.

The Bechtel team elected to exclude certain types of facilities from their model,

* No attempt was made to evaluate the default data inputs.

and the model in its current form* may not be immediately appropriate for evaluating the impact of new technologies. However, the model structure appears to be sufficiently adaptable to allow someone familiar with the model to incorporate additional types of facilities. This is particularly important if the time horizon of the model is to be shifted beyond the year 1995.

Application to Power System Planning

The Bechtel model is of some use to electric utilities for planning at the national or regional levels. In addition to considering the scheduling of facility siting and construction, the model indicates requirements for various types of labor and raw materials. Using this system would provide some measure of insurance against ignoring some latent future shortage. Therefore, the model can be a useful tool to the utility industry at the strategic level. However, the model has several deficiencies as a planning tool for electric utilities due to restrictions imposed by the methodology.

This system does not address the economic impacts of attaining an energy mix. The costs of certain resources or construction of certain utilities may not be suitable with respect to the national or a regional economy. In fact, the cost of the overall energy mix may not be consistent at an economic level. Clearly, the energy system planning model was not designed to address these issues. However, for the purpose of analyzing an energy policy, the issues must be addressed by some other model or by another means.

This model also does not account for environmental impacts. Even if one suppresses the economic questions to concentrate on the physical elements, the air and water pollution associated with energy production is an important consideration. In case of environmental impacts, the structure of the model could accommodate the generation of the pollutants associated with energy mix, as well as the impacts on the health and safety of labor and the surrounding environments. However, the exclusion of the economic and demand aspects preclude any endogenous cost-benefit analysis concerning environmental impacts.

Another set of concerns to power system planners that are not handled in this modeling framework are the effects of regulation. In energy policy-making, regulation is the mechanism for controlling the system and therefore regulation schemes (in addition to a targeted fuel mix) must be evaluated. This model does not indicate what regulatory practices are necessary for attaining the required facilities, materials, and labor force. The effects of regulation siting and construction are partic-

* Since this review is based on 1975 documentation, some modifications may have been implemented.

ularly crucial for electric utilities.

The Bechtel model does not account for seasonal variation in the fuel mix, nor does the model consider other features of interest to utilities such as load and reliability. These features are, to some extent, reflected in the inputs and must therefore be analyzed prior to using this model.

This model uses the notion of a "nominal facility" in determining capital, labor, equipment and material requirements. It was recognized that this approach encounters some problems in economies-of-scales, since these requirements will not generally change at a linear rate as the size of the facility increases. Poor choices of a nominal facility could lead to errors of over 30 percent. This approach was probably unavoidable, given the size of the energy system, but the user should be cognizant of this possibility.

In conclusion, the Bechtel Energy Supply Planning Model appears to be useful as one of a set of energy planning models, but has serious deficiencies in serving as the primary planning model. It would seem appropriate to use this model more as a check to planning, rather than a tool to design a national energy plan. For instance, one could design a national plan using some other energy model and then check the feasibility of that plan, using the Bechtel model to determine whether any serious resource or scheduling inconsistencies existed.

CONCLUSIONS AND RECOMMENDATIONS

In this study we have examined six models, each of which represents a different type of model, with respect to their ability to analyze problems relevant to electric power systems, and particularly regional aspects of power system planning. The major characteristics of the models are summarized in Table IV-1.

Each of the models can contribute useful information to regional power system planning. The H-J model can study the interaction between economic activity and energy consumption, the allocation of resources (energy, materials, labor, and capital) among competitive uses, and the changes in production resulting from changes in the prices of factor inputs and final outputs. The BNL models BESOM and DESOM can address such issues as the implications to the energy system of resource limitations and new energy production and/or end-use technologies. The SRI-Gulf model can be used to study synthetic fuel development, fuel and energy prices, and the impacts of a nuclear moratorium on the price and availability of energy. The Regionalized Electricity Model (REM) can be used to perform studies such as financing alternatives for electric utilities and impacts on the electric utility industry of different capital and fuel cost scenarios. The Wisconsin Regional Energy Model (WISE) can be

Table IV-1 Summary of Model Features

Model Characteristics	BESOM DESOM	WISE	H-J	SRI-Gulf	REM	Energy Supply Planning Model
Author(s)	Hoffman	Foell	Hudson and Jorgenson	Cazalet	Baughman and Joskow	Carruso and Gallagher
Affiliation	BNL	University of Wisconsin	DRI Harvard	SRI	MIT	Bechtel
Methodology						
• Overall	LP Optimization	Simulation	Econometric	Process Network	Simulation	Accounting
• Supply	Engineering	Engineering	Econometric	Process	Engineering	Engineering Economics
• Demand	Exogenous	Socioeconomic	Econometric, I/O	Informal Econometric	Econometric	Not applicable
Aggregation						
• Space	National, Homogenous	State, Regionalized	National, Regionalized	National, Regionalized	National, Regionalized	National, Regionalized
• Time	BESOM, Static DESOM, Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
• Sector	Energy	Energy with Electricity Emphasis	Whole Economy With Energy Emphasis	Energy	Electricity	Energy

used to forecast the regional (Wisconsin) demand for energy considering a variety of technical and social factors. WISE can be applied to other regions (and has been) but, of course, the appropriate data for the region must be used. The Bechtel model can calculate the total direct capital, manpower and material resources required to bring on-line and to operate the energy supply and transportation facilities required for any specified future energy mix in the 1975 to 1995 time frame.

It would not be efficient to attempt to design a single model which could at once model the national economy and at the same time analyze the details of the electric power system within a single region. Models that attempt too much, become bogged down in detail; clumsy, inefficient and expensive to execute. It is therefore recommended that a hierarchy of models be selected or developed for use in regional power system planning. The higher level models would only need to be executed infrequently to supply the exogenous variables required by the more detailed regional models(s).

There is a requirement for a model that is specifically designed to study regional power system problems. The models studied (and other similar models) can make valuable contributions to regional power system planning, but there is a gap that none of these models can fill. In particular, none of the models are capable of evaluating the impact of regional planning on electric power systems. What is required is a regional model emphasizing the electric power sector (something like a combination of REM and WISE), but with more than one utility modeled, so that inter-utility effects can be studied.

Issues that could be investigated with such a model include the impact of regional planning on:

- Reserve margin requirements
- Capital requirements
- T&D requirements
- Regional expansion plans
- Regional load forecasts
- Regional load management
- Interties (inter- and intra-regional)

The model should also be capable of analyzing the effect of regional planning on such fuel supply questions as:

- Limitations on supply and capacity
- Fuel substitution
- Fuel transportation alternatives
- Reliability of fuel supply

In addition, the model should be detailed enough to estimate first order environmental effects for the region, so that the environmental impacts of regional planning can also be assessed.

A key consideration in the development of a regional power system model to be used in a hierarchy of models, is that it be consistent with those models. Thus, it is essential that the overall hierarchy be well-defined prior to designing the regional model, particularly if the model is to be integrated with an existing model.

The regional power system model will require additional data in many topic areas. More detailed end-use data are needed to allow the development of refined end-use models. Data are needed to estimate own-price and cross-price elasticities for the fuel alternatives by end-use. Additional data are needed to better define T&D costs; information on the variation of transmission line length, the capacity of transmission substations, distribution line length, distribution substation capacity, line transformer capacity, and number of meters with such factors as customers of various types, load density, area, and energy demand. The sensitivity of T&D and O&M costs to terrain and weather condition needs to be determined.

Regional energy models with an emphasis on the supply and consumption of electric power are situated in between national level energy/economy models and single electric utility models. As such, they must retain much of the generality of the former while incorporating much of detail of the latter. This new breed of model can plug the model gap and become an important tool to aid decision-makers in regional electric power system policy analysis and design.

**FINAL REPORT
ENERGY
SUPPLY/DEMAND
MODELS**

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ENERGY DEMAND SUPPLY MODEL SELECTION CRITERIA

The electric utility sector must constantly assess its long-range planning. In the past, such analysis has been based on simple models. Today, large-scale models and modeling techniques are available tools which contribute to the understanding of electric utility planning decisions.

In this study, five of the largest energy supply/demand models are analyzed and compared in-depth:

- Brookhaven Energy System Optimization Model (BESOM)
- Project Independence Evaluation System Model (PIES)
- Gulf-Stanford Research Institute Energy Model (Gulf-SRI)
- DRI Annual U.S. Energy Model (DRI)
- DRI Service Area Load Forecasting System; Utility Consulting Group (DRI-LFS).

Models were first evaluated with respect to their treatment of 1) the electric utility industry, 2) the full energy and economic system, 3) regional economic and energy differences, 4) energy and economic feedbacks, 5) the energy demand sector, 6) the energy supply sector, and 7) the integration of energy demands and supplies and the determination of prices. The models were then evaluated on an overall level in reference to their applicability and ease of use. Each of these selection criteria will be expanded below.

The electric utility industry must be modeled in detail. Important factors which should be incorporated into the model framework include the fluctuating nature of electricity demands, regulatory constraints, capacity constraints and the lead times associated with the introduction of new capacity, technological change and conversion efficiencies. Because electricity cannot be stored, generating capacity requirements are dictated by the maximum kilowatts required at any one point in time during the year rather than the total level of demand. The fluctuating nature of the demands also defines an optimal generating capacity mix, encompassing a variety of plant types. At the same time, Federal and state regulatory constraints or capacity constraints on both generation equipment and transmission and distribution equipment can significantly affect the feasible generation mix. Modeling efforts must consider these constraints to adequately reflect the utilities operating environment.

Equally as important as the detail within the electric utility sector is the modeling of the full energy and economic environment in which the electric utility is operating. How other energy industries are modeled is a critical consideration because utilities use other energy forms in their generation processes and electricity competes with fuels in satisfying energy end-use demands. Economic activity modeling is of value in projecting the level of energy end-use demand and therefore electricity demand in the service area.

The regional level of a model must be consistent with the scope of the model. The regional area of principal interest in this study is the electric utility service area. But subnational models (regional models encompassing the U.S.) are viewed as a necessary step in the modeling of a particular service area. It is at the subnational level that regional fuel prices, fuel demands, and fuel availabilities are most realistically determined. The sum of the regional fuel availabilities must be consistent with national supplies. Subnational models can force such consistency through the price mechanism or through supply constraints, while regional service area models cannot. This suggests that regional service area models should be linked with subnational models. Fuel prices and availabilities, as determined within a subnational model, would then be supplied as inputs to the regional service area model. The service area model could then focus primarily on the electricity sector.

Hence, both subnational and regional service area models will be open to review. In addition, the regionality criterion will be completely discounted if methodology introduced in a national model could be applied at the service area level as well.

Demand sector relationships which should be considered in energy modeling include the treatment of energy end use versus fuel demands, dynamic versus static demand projections, fuel interdependencies, curtailments and regulatory constraints.

Factors deemed important in the supply sector include modeling the depletable nature of energy resources and the transportation of energy supplies across regions, energy conversion technologies, technological changes, capacity constraints, and behavioral lags.

Both energy demands and energy supplies are dependent upon price and it is this joint dependency that creates the stumbling block in energy demand/supply models. The means by which the models have treated this fixed point problem was a primary consideration in the model selection process.

The applicability criteria refers to the range of problems to which a model can be applied. The consideration here is the ability of the model to answer questions of interest to the electric utility industry.

The final criteria, ease of use, may very well be inversely related to the level of detail and sophistication of the model and its solution technique. The amount of input required by the model in the form of judgmental parameters or historical data observations, the computer time required to forecast with the model, and the ability to access and manipulate the model must also be considered. A trade-off between detail and ease of use may be necessary and at least must be evaluated.

If one were to incorporate all the factors which impact a regional electric power system within a single model framework, a highly unmanageable model would result. It is this researcher's viewpoint that utility long-range planning can be accomplished more effectively through an integrated system of models. For example, a macroeconomic model with general energy-economic relationships could be used to simulate the economy. Economic projections from this model could then be input exogenously into a more detailed subnational, full energy system model. In turn, this model could simulate the energy sector, projecting energy prices, demands and availabilities, all of which could be fed into a regional electric utility model. The electric utility model could then focus on issues pertinent to the utility and its service area. In a system of models, feedback effects must also be considered. If the feedback between models is strong, iterative solution techniques could be used. In summary, a system of models would enable one to view in detail the electric power generation requirements in a particular region and the means by which these requirements can be met while not losing perspective of the national economy and the full energy system.

The models chosen are believed strong in one or more of the aspects outlined above. They vary in scope and would complement each other in an integrated system of models.

The BESOM Model, while national and while its demand and supply sectors are exogenous, was selected because of the techniques it employs in integrating demand and supply and converting energy forms into electricity. These techniques could be applied at the subnational or regional level as well (RESOM).

The PIES Model is an integrated system of models, and it is the integrating model that is its primary strength.

The Gulf-SRI Model is unique in that it attempts to incorporate its demand and supply models within a generalized equilibrium framework rather than a linked system. Here it is interesting to compare the generalized equilibrium solution technique with the integrated model system approach. While these approaches are mutually exclusive in theory, economic and energy demand models have been linked with the Gulf-SRI Model in practice. This is because the economic considerations and therefore the demand sector detail within the framework are weak. To expand these sectors within the model would add more complexity to an already highly complex model.

The DRI Model, another linked system of models, is of interest because of its detailed demand sector modeling, its consideration of economic factors, and its resource supply modeling.

Finally, the DRI-LFS Model was selected because of its detailed electricity demand sector modeling at the service-area level.

Summary Comparison

The BESOM, PIES, and Gulf-SRI Models are considerably detailed with respect to supplying electricity. The models project the generating plant mix and fuel uses of the utilities required to reliably meet electricity demands. The electricity demand projections behind the supply requirements are modeled with less sophistication. The DRI Economic/Energy System and the DRI Load Forecasting System model electricity demands through in-depth economic analyses.

All models, except the Load Forecasting System, model the full energy system. The LFS simulates with economic conditions, regional prices, and supply constraints consistent with the national economic energy picture through its link with the DRI Economic/Energy System.

PIES, Gulf-SRI, and the DRI Energy System are regionalized models of the U.S. BESOM is a national model, but a regionalized version is under development. The LFS models only a particular utility's service area.

BESOM is a linear programming model. The objective of the linear program is to minimize energy system costs subject to energy technologies, end-use demands, and resource supply curves.

PIES is an integrated model system consisting of an econometric demand model, primary resource supply models, an integrating model, and an iterative solution algorithm. The integrating model is also a linear programming model which maximizes the sum of consumers' and producers' surplus subject to energy technologies, existing refinery and utility capacity, and the demand and supply curves obtained from the demand and supply models.

The Gulf-SRI Model is a generalized equilibrium model which maximizes the present discounted value of energy production, processing, and conversion over all future time periods. A special algorithm is employed to generate the market clearing prices for the general equilibrium solution.

The DRI Economic/Energy System is an integrated system of models consisting of a Macroeconomic Model, an econometric Energy Core Model, and a geological-economic Coal Supply Model, and Distribution Model. The models are linked through iterative solution techniques. The demand function specifications in the model are derived from utility maximization and producer cost minimization assumptions. Coal demands, supplies, and prices are derived through cost minimization.

The Load Forecasting System is an econometric demand model with demand functions formulated under assumptions of utility maximization and cost minimization.

Economic factors influence the demand projections in the PIES, Gulf-SRI, DRI Energy System, and DRI-LFS. Operation of the DRI Energy System also considers the feedback effects of energy on the economy.

Both BESOM and the Gulf-SRI Model classify demands according to end use. In BESOM, end-use demands are exogenous to the model framework, and the distributed or energy product forms which satisfy the end-use demands are determined within the BESOM linear program, based on the relative costs of the alternative means. The level of energy product demands projected by the model represent a static, optimal energy product mix. The Gulf-SRI Model has been simulated under two different specifications. Under the first specification, end-use demands are endogenous to the model, modeled as a function of general regional economic activity variables. In the second specification, end-use demands are exogenously input from the DRI Energy System. Under both specifications, energy product demands are derived as functions of the end-use demands, relative energy prices, and relative energy quality characteristics. The demand specifications are dynamic, subject to existing capacity constraints, behavioral lags in adjustment, and technological change.

Both the DRI Energy Model and LFS include analyses of the energy-using capital stocks in determining energy product demands. Demands are also based upon detailed economic analyses, relative energy product prices, and the prices of energy relative to other goods and factors. Demand functions have a dynamic specification, incorporating behavioral lags in adjustment.

PIES models energy product demands in a manner similar to the DRI Energy System. But energy-using capital stocks are not included in the demand functions, nor is the level of economic detail as comprehensive.

Only the primary resource supply curves in the Gulf-SRI Model and the Coal Model of the DRI Energy System incorporate cumulative production into the cost function. The cost functions representing resource supply in BESOM and PIES do not consider depletion explicitly. The supply curves for the major primary energy resources are exogenous inputs to BESOM and the Gulf-SRI Models. Supply models are used to develop the resource supply curves in both the PIES Model and the DRI System.

Energy product prices in the BESOM and PIES Models evolve as the shadow prices of linear programming solutions. In BESOM, the prices which generate the end-use demand projections are not consistent with the shadow prices projected in the solution within the framework of the model. PIES employs an iterative solution algorithm to obtain consistency between the prices which generate demands and the linear programming solution prices.

The prices in the Gulf-SRI Model represent market clearing prices. The consistent set of prices is generated through the use of a special solution algorithm.

Prices in the DRI Energy Model result from a combination of exogenous price and regulatory assumptions, linear programming shadow price solutions, and average cost pricing. The price of imported oil is exogenous to the model. Domestic oil and natural gas prices are linked to imported oil prices and inflation rates through regulatory assumptions. Coal prices are derived as market clearing prices through iterative solutions of the Energy Core Model and the Coal Supply and Distribution Model. Electricity prices are derived as the average generation cost.

Applications of BESOM and the Gulf-SRI Model include analysis of interfuel substitutions, long-term technology assessments, and in BESOM the environmental effects of various technologies. The PIES and the DRI Economic/Energy System are used to analyze national economic scenarios and national or regional energy policies and regulations. The DRI System is also capable of analyzing the impact of the energy sector on the national economy. The Load Forecasting System analyzes the impact of different economic scenarios, government policies, conservation and load management programs on a particular utilities' electricity demands.

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I. THE BROOKHAVEN ENERGY SYSTEM OPTIMIZATION MODEL

The Brookhaven Energy System Optimization Model, BESOM, is a linear programming model that "optimizes" energy flows for the entire energy system subject to a given set of constraints. The optimal energy flow is typically specified as that which minimizes total energy costs, although the problem can be restructured to minimize resource consumption, environmental effects, or other objectives. Resource supplies (step-wise linear supply functions), energy end-use demands, and energy technologies are givens to the system. The constraints on the system require that resource supplies not be exceeded, demands be satisfied, environmental impacts and pollution emissions fall within specified limits, and the flow of energy from resource supply to end-use adhere to the given technologies. Solution of the linear program provides the optimal energy "activity levels" and the dual variables, or "shadow prices," associated with the program constraints.

The structure of BESOM can be summarized algebraically as follows:

Primal Solution:

$$\begin{array}{ll} \text{Minimize} & C'X \\ \text{Subject to} & AX \leq b \\ & X \geq 0 \end{array}$$

where

- C = cost vector
- A = constraint matrix
- b = constraint vector
- X = solution vector of energy flows (energy activity levels)

Dual Solution:

$$\begin{array}{ll} \text{Maximize} & \lambda'b \\ \text{Subject to} & \lambda'A \leq C' \\ & \lambda \geq 0 \end{array}$$

where λ = dual variable or "shadow price" vector.

The cost vector, C, the constraint vector, b, and the constraint matrix, A, are exogenous inputs to the model, while the solution vector, X, and the vector of shadow prices, λ , from the dual solution are the outputs of the model. The solution vector, X, can be interpreted as the equilibrium production level for each of the energy activities while λ is the set of market clearing prices associated with these production levels.

The scope of the BESOM model will first be outlined, followed by a detailed discussion of the model's input requirements, constraint set and objective function.

MODEL SCOPE

The linear programming problem formulated by BESOM is based upon the Koopmans-Hitchcock-Kantorovich "transportation problem." Scarce energy resources are allocated to a variety of energy end-use demands through a network of conversions. Figure 1-1 illustrates the flow of energy through the network. Primary resources enter the network at the bottom of the figure. The resources can be routed along alternate paths in satisfying the end-use demands at the top of the network. Resource supplies are first brought into the system through extraction and then processed into intermediate energy forms. At this point, the intermediate energy form can be directly utilized by an end-use device to satisfy an end-use demand or can be routed to the electric utility sector for electricity and heat generation before being utilized by an end-use device. Figure 1-2 illustrates the detail with respect to generation and transmission in the network. Electricity or heat can be generated by either central station plants or

decentralized plants. Backup electricity generation requirements are associated with the various generating plants. Central station generation is passed through a transmission system on route to end-use devices, while decentralized generation is not. Electricity and heat are then utilized by an end-use device to satisfy an end-use demand, in the same manner as the other intermediate energy forms.

The resource availabilities, the end-use demand requirements, and the technologies or efficiencies associated with the flow of energy through the network are specified in the constraint set of the linear program, while the costs associated with each technology are entered into the objective function. The constraint set and the objective function completely describe the linear program.

BESOM is a static model that solves for the optimal energy flow for some future year. The model can be solved year by year to form a dynamic solution.* The procedure for a year-by-year solution requires: 1) constraining capacity levels in subsequent solutions to be at least as great as capacity brought on line in previous solutions less depreciation, and 2) adjusting the supply curves for each primary energy resource to reflect cumulative productions implied in previous solutions. This technique provides an optimal solution for each year, but not necessarily an optimal solution for the entire forecast interval. DESOM is the dynamic counterpart of BESOM. A DESOM solution differs from a year-by-year solution of BESOM in that the solution provides the optimal energy flows for the entire forecast interval. Its objective function is a multi-period extension of BESOM's objective function where the energy costs associated with each future period are the present discounted value of the energy cost in the future period. The model keeps track of new capacity additions and resource production through time. DESOM assumes perfect foresight when discounting future period costs.

BESOM is a national model. Its regional counterpart is RESOM. RESOM has been developed with regional detail for the nine census regions, but the model is easily adaptable to other regional breakdowns.

The detail in BESOM with respect to energy resources, synthetic fuel plants, electric generating plants, intermediate energy forms, end-use devices, and end-use demands is summarized in Table 1-1. Energy can be supplied directly through extraction or importation or indirectly through synthetic fuel plants or electric power generation. Fourteen forms of domestic energy resources are included in the model along with three imported energy resources. Nine types of synthetic fuel plants are considered in BESOM and 31 classifications of electric generating plants.

Electric generating plants are first divided between central station plants and decentralized devices. Central station plants are further categorized as central station electric (i.e., those generating only electricity) and central station/district heating plants (i.e., those generating both electricity and waste heat). There are 14 types of central station electric plants and seven types of central station/district heating plants. Electricity and waste heat can be generated from 10 types of decentralized devices.

Generation plants are classified as reliable or unreliable, and electricity usage is categorized as either primary or as backup to unreliable generating plants.

The extraction, importation, and/or simple processing of the energy resources, the production of synthetic fuels and the generation of electricity and heat result in a maximum of 14

FIGURE I-1

BROOKHAVEN ENERGY SYSTEM OPTIMIZATION MODEL

FIGURE I-2

TABLE 1-1

Model Detail

I. Resources (RS)

Domestic Crude
 Imported Crude
 Shale Crude
 Domestic Natural Gas
 Underground Coal
 Strip-mined Coal
 Geothermal
 Solar
 Imported Natural Gas
 Hydropower
 Uranium
 Imported Residual
 Wood
 Biomass
 Municipal Solid Waste
 Wind

II. Synthetic Fuel Plants (SP)

Oil Syngas
 High Btu Coal Gas
 Electrolytic Hydrogen
 Coal Methanol
 Coal Hydrogen
 Coal Liquids
 Low Btu Coal Gas
 Anerobic Digester
 Refuse-derived Fuel

III. Electric Generating Plants (EL)

A. Central Station Electric (CS)

Coal Steam
 Coal Combined Cycle
 Coal FBC
 Oil Steam
 Oil-coal Steam
 Oil Combined Cycle
 Gas Turbine
 Gas Steam
 LWR
 LMFBR
 Hydroelectric
 Geothermal Electric
 Solar Electric
 Pumped Storage

B. Central Station/District Heating Plants (DH)

Coal Steam/DH
 Coal Combined Cycle/DH
 Oil Steam/DH
 Oil Combined Cycle/DH
 Gas Turbine/DH
 Gas Steam/DH
 Coal FBC/DH

C. Decentralized Devices (DD)

Total Energy System
 Fuel Cell
 Steam Topping Cycle
 Gas Turbine Topping Cycle
 Auxiliary Generator 1
 Auxiliary Generator 2
 Battery Storage
 12 KW Wind System
 70 KW Wind System
 Photovoltaic

IV. Intermediate Energy Forms (IEF)

Electricity
 Oil
 Gas
 Coal
 Heat
 Methanol
 Hydrogen
 Solar
 Geothermal
 Nuclear
 Low Btu Gas
 Wood
 Hydropower
 Wind

V. End-Use Devices (D)

Heat Pump
 Combined Space/Water Heat
 Conventional Technology
 FBC
 Steam Topping System
 Gas Topping System

VI. End-Use Demands (DM)

Miscellaneous Base Load Electric
 Miscellaneous Intermediate Load Electric
 Peak Load Electric
 Pumped Storage and Electrolysis
 Battery Storage
 Thermal Low Temperature
 Process Heat Medium Temperature
 Thermal High Temperature
 Iron Ore Reduction
 Petrochemical
 Space Heat
 Air Conditioning
 Water Heat
 Air Transport
 Truck, Bus, Ship
 Rail
 Auto
 Decentralized Electric Back-Up
 Central Station Electric Back-Up

VII. Environmental Detail

A. Environmental Effects (POL)

Particulates
 Nitrogen Oxide
 Sulfur Dioxide
 Hydrocarbons
 Carbon Monoxide
 Aldehydes
 Carbon Dioxide
 Acids
 Bases
 Phosphates
 Nitrates
 Other Dissolved Solids
 Suspended Solids
 Nondegradable Organics
 BOD
 COD
 Thermal
 Solid Wastes
 Land Use
 Deaths
 Injuries
 Man-Days Lost

B. Radioactive Emissions

POP-Exposure
 KR-85
 Tritium
 High Level Waste
 Heat

different energy forms for any solution of BESOM. Intermediate energy forms can be converted to end use through six different types of end-use devices.

Nineteen categories of end-use demand are considered in the model. Six of these 19 categories can only be satisfied by the intermediate energy form, electricity. Three of the 19 demand categories are endogenously determined by the model. All three are demands which can only be satisfied by electricity. The remaining 16 end-use demands are exogenous to the model.

The load duration characteristics of the end-use demands are specified in the model. Electricity generated to meet demands is split between the base or intermediate portion of the demand and the contribution of the demand to the peak, based upon the load duration characteristics of the demand.

End-use demands are further classified as daily on- or off-peak demands. In addition, the air conditioning end-use demand is classified as a seasonal on-peak demand and space heat demand is classified as a seasonal off-peak demand.

A total of 22 environmental effects and five radioactive emissions are associated with 42 emission sources. The emission sources are the activities of energy system such as resource extraction or importation, the simple processing of resources, synthetic fuel production, electric and heat generation and end-use conversion.

Although not discussed in this review, BESOM also provides an option to disaggregate the cement industry from the process heat sector. A variety of processes are considered in this option to manufacture cement. They provide energy conservation alternatives and innovation displacements for process plants.

MODEL INPUTS

The input requirements to BESOM can be divided into five general categories: 1) resource supplies, 2) demands and demand characteristics, 3) technologies (efficiencies and costs), 4) environmental impact factors, and 5) market penetrations.

1. Resource Supplies

Resource supply curves for the 16 primary resources included in BESOM are exogenous to the model. (See Table I-1.) Supply curves are estimated outside the BESOM model framework. A nine-step piecewise linear approximation is then made to the supply curve. For each primary resource, the cost in dollars per million Btu at each step of the linear approximation, the upper limit in quadrillion Btus of each step and the total limit on the resource use are input to the model.

2. Demands

End-use energy demands for 19 categories are specified in the model. The demands are listed in Table I-2, along with the numbers which correspond to their identification in the BESOM model. A disaggregation by the residential/commercial, industrial, and transportation sectors is also implied by the demand categories, since each category (except peak load electric) is particular to just one of the three sectors. This correspondence is specified in Column 1 of Table I-2. Six of the end-use categories specify electricity demands directly, since the end-use demands can only be satisfied by electricity. These six demands are identified in Column 2 as nonsubstitutable demands.

The demand levels in quadrillion Btus are exogenous inputs to BESOM for 16 of the 19 end-use demand categories. (See Column 3.) The exogenous demand specification implies that these end-use demands will not change under alternative

simulations of the linear program. In particular, these end-use energy demands will not respond to changes in the price of energy relative to the price of other goods or factors. The three endogenous demands vary with the use of the intermediate energy form, electricity, in satisfying the other end-use demands. The constraint equations which determine these demand levels are discussed in Appendix A.

Several characteristics of each end-use demand category must also be inputted to the model. They include the peak type, the load factors (primary and back-up) and the peak fractions (primary and backup) associated with each demand.

Demand peak type refers to daily on-peak, daily off-peak, seasonal on-peak, and seasonal off-peak. In Column 4 of Table I-2, the daily peak classification is listed for each demand which could be satisfied by electricity. The space heat and air conditioning demands have been further classified as seasonal off-peak and seasonal on-peak demands, respectively. This distinction among demand peak types is important in the model because the amount of on-peak demand satisfied by electricity determines the electricity generation capacity requirements. In addition, the amount of off-peak demand which can be satisfied by electricity is limited by the capacity generated from the on-peak demands. (See Appendix A.)

Primary and backup load factors (Columns 5 and 6 of Table I-2) must be specified for each daily on-peak demand and for each seasonal demand. The load factors represent the demand duration. The primary load factor is defined as the ratio of the average rate of demand met by the primary generation source over a given period to the peak rate occurring in the period. Similarly, the load factor for backup electricity for each demand is defined in terms of demands met by the backup generation source. The daily and the seasonal primary load factors for air conditioning are assumed to be the same. A daily load factor for space heat is not required by the model, since space heat is a daily off-peak demand. The load factor specified for this demand is the seasonal load factor.

A peak fraction must be assigned to each daily on-peak demand category (except category 3, peak load electric) for both primary and backup electricity generation. The peak fraction for primary (backup) generation is defined as the fraction of electricity generated by the primary (backup) generation source for use by a demand category at the primary (backup) load factor. The following example explains the above definition for peak fraction.

Let E_i = electricity delivered from the primary (backup) generation source to satisfy end-use demand, D_i .

X_i = the intermediate or base load portion of the electricity delivery (i.e., off-peak portion of electricity delivery E_i).

Y_i = electricity delivered to satisfy end-use demand D_i by the primary (backup) generation source which must be generated coincidentally with the electrical system peak (i.e., peak portion of electricity delivery, E_i).

Then $E_i = X_i + Y_i$

$$F_i = \frac{Y_i}{X_i + Y_i}$$

F_i = fraction of the generation which must be supplied coincidentally with the electrical system peak demand.

TABLE I-2
END-USE DEMANDS

Category	Sector	Energy Require- ment	Variable Type	Demand Peak Type	Load Factor (Primary)	Load Factor (Backup)	Peak Fraction (Primary)	Peak Fraction (Backup)
1. Miscellaneous Base Load Elec.	R/C	N.S.E.	exog.	daily on-peak	1.00	same	.05	same
2. Misc. Intermediate Load Electric	R/C	N.S.E.	exog.	daily on-peak	.50	as	.10	as
3. Peak Load Electric		N.S.E.	endog.	daily on-peak	.10	primary		primary
4. Pumped Storage & Electrolysis	IND	N.S.E.	exog.	daily on-peak				
5.								
6.								
7. Battery Storage	IND	N.S.E.	exog.	daily off-peak				
8. Thermal Low Temperature	R/C		exog.	daily on-peak	.75		.05	
9. Process Heat Medium Temp.	IND		exog.	daily on-peak	.75		.05	
10. Thermal High Temperature	IND		exog.	daily on-peak	.75		.05	
11. Iron Ore Reduction	IND		exog.	daily on-peak	1.00		.05	
12. Petrochemicals	IND		exog.	daily on-peak	1.00		.05	
13.								
14. Space Heat	R/C		exog.	daily off-peak seasonal off-peak	(.44)			
15.								
16. Air Conditioning	R/C		exog.	daily on-peak seasonal on-peak	.25		.20	
17. Water Heat	R/C		exog.	daily off-peak				
18.								
19. Air Transport	TRAN		exog.					
20. Truck, Bus, Ship	TRAN		exog.					
21. Rail	TRAN		exog.	daily on-peak	.50		.10	
22. Auto	TRAN		exog.	daily off-peak				
23. Decentralized Electric Back-up	IND	N.S.E.	endog.					
24. Central Station Electric Back-up	IND	N.S.E.	endog.					

R/C = residential/commercial sector
 IND = industrial sector
 TRAN = transportation sector
 N.S.E. = non-substitutable electric energy demand
 exog. = exogenous variable to the model
 endog. = endogenous variable

Note: Load factors for off-peak demands are assumed implicitly to have unit values which implies peak fraction values of zero.

and solving for Y_i

$$Y_i = \frac{F_i}{(1-F_i)} X_i = g_i X_i$$

where g_i , which relates the peak generation to the off-peak generation, is the peak fraction defined above for the primary (backup) generation source.

Peak fractions must be specified for all end-use demand categories classified as daily on-peak demands except the endogenous peak load electric category. The peak fractions are used to generate the demand level for peak load electric. (See Appendix A)

3. Technologies

The technologies associated with the stages of processing of energy from primary resource to end-use form are described by efficiency factors and costs. Both the efficiency factors and the costs are exogenous inputs to the model. The technologies in BESOM include:

- a. extraction and importation of natural resources,
- b. synthetic fuel production
- c. fuel transportation and simple processing,
- d. electricity and heat generation,
- e. electricity and heat transmission and distribution, and
- f. end use conversion by utilizing devices.

The efficiency factor for each technology relates the Btu content of the process input to the Btu content of process output. The cost for each technology includes fuel delivery costs (transportation costs, taxes, or tariffs), labor costs, and annualized capital costs. Each efficiency factor is discussed in Appendix A as it enters the constraint equations, while costs, which are elements in the objective function, are discussed as they enter the objective function. The required technological coefficients are listed in Table I-3.

4. Environmental Impact Factors

Environmental impacts are associated with the flow of energy as it passes from supply source to intermediate energy form, to converted energy form, and finally to end use. The impact factors for 42 kinds of emission sources and for 22 pollution types are inputs to the model. Table I-1 lists the environmental impact factors considered in BESOM.

5. Market Penetrations

An optional group of inputs to BESOM includes specified limits on various activity levels. For example, an upper limit can be imposed on a fuel used in electricity generation, a limit can be specified for the amount of synthetic fuel which can be produced, or the amount of an intermediate energy form used by an end-use device can be limited.

MODEL OUTPUTS

Solution of the linear program provides: 1) the optimum energy flows, that is, the activity levels for the intermediate energy forms associated with the conversion of energy from resource supply forms to end-use demand forms, 2) the total resource use, 3) the electricity generating capacity by plant type and the plant load factors, 4) the environmental impacts and pollution emissions implied by the optimal energy flow, 5)

the total system cost associated with the optimal solution, and 6) the dual variables, or "shadow prices," associated with the constraints.

THE CONSTRAINT SET

The constraint set will be discussed in an order which follows the flow of energy through the system as pictured in Figure I-1 above. The equations in the constraint set can be grouped and summarized as follows:

1. Supply constraints—impose limits on resource supply.
2. Simple processing constraints—reflect the technology behind the cleaning, transportation, and simple processing of the resources into intermediate energy forms and the production of synthetic fuels.
3. Demand constraints—require that the given levels of end use demand be satisfied. The efficiencies of the end-use devices used in conjunction with intermediate energy forms to satisfy the end-use demands are also accounted for in the demand constraints.
4. Environmental constraints—impose limits on environmental effects and pollution emissions.
5. Market penetration constraints (optional)—impose limits on various activity levels.
6. The electricity sector constraints—the constraint equations which model the electricity sector have been further categorized as follows:
 - a. Fuel to electricity conversion constraints
 - b. Fuel to waste heat conversion constraints
 - c. Electricity and waste heat transmission constraints
 - d. Storage conversion constraints
 - e. Electricity delivery constraints, primary versus backup
 - f. Electricity demand constraints, peak versus off-peak
 - g. Generating capacity requirement constraints
 - h. Off-peak generation constraints

With the constraint equations in the electricity sector of BESOM, the model determines

- electricity demands,
- peak electricity demands,
- backup electricity demands,
- optimal generating capacity,
- energy input requirements of utilities,
- waste heat generation, and
- limitations on daily and seasonal off-peak generation.

Functional notations adopted from the BESOM documentation, with only slight modifications, have been included with the constraint equation descriptions for clarity in Appendix A. An explanation of the mnemonic structure is included in this appendix.

TABLE I-3

Exogenous Technological Coefficients

$q_{(EL)}$	the proportion of the electricity demand to be met by the back-up for the unreliable generating plant (EL)
$CE_{(IEF)(EL)}$	efficiency factor for converting intermediate energy form (IEF) to electricity in generating plant (EL)
CEBS	efficiency factor for converting electricity to battery storage
CEPS	efficiency factor for converting electricity to pumped storage
$EUE_{(IEF)(D)(DM)}$	end-use efficiency factor for converting intermediate energy form (IEF) to satisfy end-use demand (DM) using end-use device (D)
$LG(RS_i)$	length of step i in resource (RS) supply curve for $i = 1, \dots, 9$ and for 19 resources
PEE	efficiency factor for the electrolytic process
$PF_{(EL)}$	plant factor for generating plant (EL) defined as the ratio of usable plant capacity to installed capacity
$SPE_{(RS),(IEF)}$	simple process efficiency factor for converting resource (RS) into intermediate energy form (IEF)
$TE_{(CD)}$	transmission efficiency factor for central station plant (CD)
$TWE_{(DH)}$	transmission efficiency factor for district heating plant (DH)
$WCE_{(IEF)(DH)}, WCE_{(IEF)(DD)}$	efficiency factor for converting the intermediate energy form (IEF) to waste heat in central station/district heating plant (DH), decentralized devices

NOTE: The efficiency factors and the costs of energy resource extraction and importation are reflected in the resource supply curves.

OBJECTIVE FUNCTION

Nine alternative objective functions can be specified in BESOM. They include:

1. Total annual system cost
2. Unannualized capital cost without end-use costs
3. Annualized system cost without end-use cost
4. Total refined oil, natural gas, and low-Btu gas
5. Total domestic oil and natural gas
6. Total oil extraction and importation
7. Total renewable resources usage
8. Total resources usage
9. A weighted index of the environmental effluents

Since the model is most often simulated to minimize total annual system cost, this alternative will be discussed further. Total annual system cost includes extraction cost, fuel delivery costs, processing costs, end-use device cost, capital recovery costs for each power plant, and the operating and maintenance cost for the plant. The objective function entries for this alternative are detailed in Appendix A, using notation consistent with the constraint set.

MODEL STRENGTHS

BESOM contains considerable electricity sector detail addressing planning problems arising because of the fluctuating nature of electricity demands, the variation in system reliability and backup requirements, the competition between electricity and fuels in satisfying end-use demands, the alternative means of

generating electricity and the environmental impacts associated with electricity generation. Through analysis of these problems, the model determines the optimal generating mix for the utilities. In the current version of BESOM under review, the generating mix is not constrained by existing capacity. Additional constraints could be entered into the linear program such that the generating mix implied by the solution accounts for existing capacity.

In the PIES and the Gulf-SRI Model discussions which follow, modeling techniques are introduced which project equilibrium versus optimal generating requirements. The generating capacity mix projected by these models takes into account the fixed nature of existing plant (PIES and Gulf-SRI) and behavioral lags in adjusting to the desired mix (Gulf-SRI).

It will also be shown in the following discussions that these two models improve upon the manner in which BESOM limits various activity levels. Rather than arbitrary constraints on the activity levels (market penetration constraints), the PIES model attempts to limit particular activities by imposing limits on the non-energy resources which are associated with operating the activities. The Gulf-SRI model introduces secondary material constraints which increase or decrease the material costs associated with each activity under rapid or low activity level growth.

Resource supply and end-use demand projections are exogenous to BESOM, but the model can be linked with detailed supply or demand models through an iterative solution technique.

Any regional disaggregation of the U.S. energy system could be modeled by altering BESOM's regional counterpart RESOM. The static nature of the model could be eliminated by simulating the model year by year and incorporating the appropriate intertemporal links. A year by year simulation of BESOM may be preferred to a simulation of DESOM because of the perfect foresight assumption embodied in the DESOM model.

II. PROJECT INDEPENDENCE EVALUATION SYSTEM

The Project Independence Evaluation System (PIES) is an integrated system of models which reflects the production, transportation, processing, conversion, distribution and consumption of energy, regionally, for the full energy system. The model system is composed of an econometric demand model, a set of supply models, an integrating or linear programming model and an iterative solution algorithm. Figure II-1 illustrates the interrelations between the models. The figure emphasizes that the level of energy supply and energy demand are functions of energy prices. The integrating model and the iterative solution algorithm combine approximations to the demand and supply curves generated by the demand model and the set of supply models to estimate market clearing prices, supplies and demands.

The PIES integrating model is a linear programming model that determines the equilibrium flow of energy from primary resource supply form in each resource supply region to distributed energy demand in each demand region. The shadow prices associated with the linear programming solution represent equilibrium energy prices. Figure II-2 illustrates the energy network defined by the linear program. Within the network, primary resources brought under production (or imported) are either transported directly from the resource supply region to the demand region or are transported to refinery or utility regions for processing or electricity generation respectively. Refinery products are then transported from refinery to demand regions. Utility regions are coincident with the demand regions they serve. Hence electricity is transmitted within the region in which it is generated.

The linear program finds the equilibrium energy flow by maximizing consumers' and producers' surplus subject to the constraints on the system. The constraints incorporate the stepwise linear resource supply curves generated by the supply models and stepwise linear approximations to the demand curves generated by the demand model. The constraints require that energy supplies not be exceeded, distributed energy demands be met and that the production, conversion, processing and transportation of primary resources and/or energy products adhere to the specified technologies and limitations of the system. Limitations such as existing plant capacity and non-resource use constrain producers from seeking minimum cost production means.

The demand curve approximations fed to the linear program are generated based upon an initial set of prices. The linear programming solution generates a set of shadow prices which may differ from the initial set. The iterative solution algorithm is therefore employed to find a set of prices which is consistent with both models. The algorithm continually refines the demand curve approximations which enter the linear program based upon the shadow prices of each previous linear programming solution, and thereby refines the equilibrium point generated in the solution.

The demand model of PIES is specified dynamically while the supply models and the integrating model are static. Cumulative production and depletion are not considered in the supply models. Solution of the model system is for one year at a time. Generally, the model is solved for the years 1980, 1985 and 1990. Although intertemporal links are not modeled explicitly into the system, model projections can be linked across the forecast years by making the existing capacity assumptions in each successive year consistent with previous year solutions.

The framework of the PIES model can be viewed as an extension and a complement to the Brookhaven Model (BESOM).

1. Stepwise linear approximations to supply curves are derived outside BESOM's framework. PIES includes models which generate these step functions for input into the linear program.
 2. Energy demands are categorized according to end uses and specified exogenously in BESOM. The distributed energy demands which satisfy these end-use demands are determined endogenously within BESOM based upon the relative costs of the energy forms. Hence interfuel substitution is modeled in BESOM while overall energy demands are not. This implies that the end-use demands upon which the solution is based are not necessarily consistent with the shadow prices generated by solution of the linear program (i.e., these demands were not necessarily determined under the same price assumptions).
- PIES models distributed energy demands in its demand model to respond to both relative energy prices and economic activity. Both interfuel substitution and intergood or interfactor substitution are accounted for within the model framework. In addition, the iterative solution algorithm employed in PIES determines a set of equilibrium prices which is consistent both with the demand projections and the linear programming solution.
3. BESOM is a national model while PIES is regional. Transportation networks link the supply, refinery and utility demand regions of the PIES model.
 4. The electricity sector detail of PIES and BESOM are complementary. Each models aspects of the industry not covered by the other. The electric utility sector of PIES is an engineering representation of the optimal expansion of the existing electricity supply system. Within the linear program, electricity demands are divided between base, intermediate and peak demand, and the optimal means of generating the electricity is determined subject to constraints on existing capacity and non-energy resource use.

A more detailed discussion of the PIES model is divided into three parts. The discussion will focus on:

1. The econometric demand model which generates distributed energy demand curves.
2. The integrating model and the iterative solution technique which determine the set of equilibrium prices, supplies and demands.
3. The detail within the integrating model with respect to the electric utility sector.

THE ECONOMETRIC DEMAND MODEL

The Econometric Demand Model of PIES models distributed energy demands in the 10 FEA consumption regions. Distributed energy demands are differentiated within each region as to consuming sector and fuel type. The sectoral breakdown consists of the household and commercial sector, the industrial sector (industrial fuel and power users), raw material users and the transportation sector. Fuel demands by the electric utility sector are determined within the integrating model rather than in the demand model. The major fuel types considered in the demand model are electricity, natural gas,

FIGURE II-1
Project Independence Evaluation System

Integrating Model Framework

Source: 1976 National Energy Outlook, Federal Energy Administration

FIGURE II-2

Project Independence Evaluation System

Flow of Materials

Source: 1976 National Energy Outlook, Federal Energy Administration

coal, and petroleum. A complete list of the fuel type detail included in the PIES model is contained in Table II-1.

Inputs to the demand model include energy prices and macroeconomic projections for the forecast period. Subject to these inputs, the model projects energy demand and price elasticities of demand for each sectoral energy demand type within each demand region.

The energy demand equations which compose the demand model were estimated econometrically using covariance analysis. Data was pooled regionally for each sectoral energy demand type. The technique constrains slope parameters in the equations to be the same across all regions while the constant term is allowed to vary by region.

Energy sectoral demand equations by fuel type were developed in a two-stage process. First, total sectoral energy demand in each region was estimated as a function of a deflated fuel price index, measures of the sector's activity level and the lagged value of energy demand. In the household and commercial sector, personal income and population reflect the sector's activity level while industrial sector activity is proxied by value added in the manufacturing industries. The lagged dependent variable in the regression gives the demand equations a dynamic specification. This specification reflects behavioral lags or the fixed nature of the energy capital stock and leads to less than full adjustment in demands when dependent variables change.

These equations model shifts in the demand for energy between other consumption goods or factors of production based upon their relative prices as well as the income or output effect on energy demand.

The second stage in the development of the energy demand equations was to model the proportion of the total sectoral energy demand met by each fuel type. For each fuel type, this portion was modeled as a function of the individual fuel price relative to the total energy price index and the lagged dependent variable. These equations model interfuel substitution with a dynamic specification.

To illustrate the demand equation formulations, the equations used to derive the industrial demand for electricity in a region will be illustrated.

First, regional total energy demand DTE_{it} (region i , in time period t) is modeled with the relation

$$\ln(DTE_{it}) = \alpha_i + B_1 * \ln\left(\frac{PTE_{it}}{P_{it}}\right) + B_2 * \ln(VA_{it}) + B_3 * \ln(DTE_{i,t-1})$$

where

PTE_{it} = total energy price index in region i in period t

P_{it} = general price deflator in region i in period t

VA_{it} = value added in manufacturing in region i in period t

$DTE_{i,t-1}$ = total demand for energy in region i in period $t-1$

and α_i is the estimated regional constant, B_1, B_2, B_3 are the estimated slope parameters.

Second, the regional demand for electricity in the industrial sector ($DELIND_{it}$) is modeled relative to total energy demand as follows

$$\ln\left(\frac{DELIND_{it}}{DTE_{it}}\right) = \gamma_i + C_1 * \ln\left(\frac{PELC_{it}}{PTE_{it}}\right) + C_2 * \ln\left(\frac{DELIND_{i,t-1}}{DTE_{i,t-1}}\right)$$

where $PELC_{it}$ = electricity price index in region i in period t

and γ_i is the estimated regional constant, C_1, C_2 are the estimated slope parameters.

THE INTEGRATING MODEL AND SOLUTION ALGORITHM

The integrating model is a linear programming model and is therefore defined by its objective function and constraint set. Demand and supply curve approximations from the demand and supply models are input to the integrating model in the same manner that the stepwise linear supply functions are input to BESOM's linear program. Given the demand and supply curve approximations, the linear program finds an equilibrium set of prices which equate supplies and demands. The equilibrium solution is found by maximizing the sum of consumers' and producers' surplus subject to the constraints of the system. This sum corresponds to the shaded area between the supply and demand curves illustrated in Figure II-3. The system constraints require that supplies not be exceeded, demands be met and the production, conversion, processing and transportation activities adhere to the specified technologies.

Both the supply and the demand curves are approximated as step functions for input to the integrating model in order to be compatible with the linear programming formation. A second approximation is made to the demand curves generated in the demand model.

In the demand model, demands for the various energy forms are modeled as functions of their own prices and the prices of all competing energy forms. The demand curve approximations fed to the integrating model express demands only as functions of their own prices. Assumptions regarding the prices of the other energy forms are embedded in the demand curve approximations. A change in the price assumptions would in general lead to shifts in the demand curves, up or down in their own price/quantity plane. The linear program uses the demand curve approximations to find an equilibrium set of prices. But the solution prices may not necessarily be consistent with the set of prices upon which the demand curves were formulated. If prices generated in the linear program are significantly different, the demand curve approximations must be changed and the linear program resolved for a new set of equilibrium prices.

The problem being defined is a fixed point problem. PIES employs an iterative solution algorithm in order to converge upon a set of equilibrium prices which bring consistency to the demand and integrating model.

The iterative algorithm is as follows:

- Step 1. Determine initial estimates of the equilibrium energy prices.
- Step 2. Using the most current estimates of the equilibrium prices compute, using the demand model, the demands corresponding to the prices and the own price elasticities of the demands.
- Step 3. Formulate step-wise linear demand function approximations which express demands as functions of own price using the price/quantity relation and own price elasticity determined in Step 2.

Table II-1

Distributed Energy Demands

Fuel Type	Sectors					
	Resi- dential	Commer- cial	Indus- trial	Transpor- tation	Raw Material	Feed- stock
Electricity	X	X	X	X		
Natural Gas	X	X	X	X		
Distillate Fuel	X	X	X	X		
Liquid Gas	X	X	X	X	X	X
Residual Fuel		X	X	X		
Gasoline				X		
Jet Fuel				X		
Oil					X	
Petroleum Coke			X			
Asphalt		X				
Coal	X	X	X	X		
Metallurgical Coal			X			

FIGURE II-3

Project Independence Evaluation System

Approximation of Supply and Demand Curves

APPROXIMATION OF SUPPLY AND DEMAND CURVES

Source: The Integrating Model of the Project Independence Evaluation System, Logistics Management Institute, September 1977.

- Step 4. Solve the linear program with the most recent demand curve approximation for a new estimate of equilibrium prices.
- Step 5. Compare the new equilibrium set of prices with the previous set of prices. If the prices are within prespecified limits, the iteration process is terminated. If not, the new prices are averaged with the old and the algorithm returns to Step 2.

With respect to electricity prices, an additional adjustment is made to prices when iterating between the demand and integrating models. The electricity prices generated by the linear program are marginal prices. The linear program models electricity supply. The relevant price to a utility in choosing its generating plant configuration and operating mix is the marginal generation cost. The relevant price to the consumer in the demand model is the average generation cost. The algorithm calculates the average generation cost as the sum of all fuel costs and capital charges relative to the level of electricity demand and returns this calculation to the demand model.

Within the integrating model, the cost correction is included as a transportation cost for electricity transmitted between the utility regions and their coincident demand regions. The objective function is altered to simulate a situation where utilities and consumers respond to different prices.

ELECTRIC UTILITY SECTOR

Electricity generation is modeled within the integrating model of PIES. The electric utility section is an engineering representation of the optimal expansion of the existing electricity supply system. It models the technology of electricity generation, the load duration curve of electricity demand, the building or conversion of facilities, and the operation of generating plants to meet electricity demands. The model considers three modes of electricity generation—base, intermediate, and peak—and 17 electricity-generation plant types. The generation and operating mix are determined for the forecast period through cost minimization. The chosen mix reflects the fluctuating nature of electricity demand, conversion technologies, and existing plant constraints.

Given to the electric utility sector of the integrating model include:

- electricity demands, by region
- electricity transmission loss efficiency factor
- load duration factors, by region
- technological efficiency factors for electricity-generation plant type, by age of plant
- technological conversion factors for conversions of generating plants to alternative plant types
- existing, committed, and deferred generating plant facilities
- transmission and distribution equipment
- transmission and distribution equipment requirements per unit of electricity generation
- operating costs per unit of operating generating equipment
- amortized capital costs.

The linear program models three aspects of the electricity industry: (1) the load duration curve which is used to produce a disaggregation of generating requirements by load category; (2) the technology behind converting energy forms into

electricity; and (3) the generation and operating mix behind the electricity generation, and the transmission and distribution system. The manner in which each aspect is modeled is discussed below.

The utility model generates a discrete approximation to 1... regional annual load duration curve, given the level of average electricity demand by region from the demand model. Average demands are first converted into electricity generation requirements based upon an exogenously specified transmission loss proportion. Regional base, intermediate and peak load generation requirements are then approximated by applying exogenous percentage shares to the total regional generation requirements. Hence, electricity generation requirements are disaggregated by the load type, or generating mode. This distinction is the key to determining the amount and type of generating capacity the system should have.

The conversions of energy forms into electricity are modeled by linear technologies which relate the Btu content of the fuel input to the Btu content of the electricity output. The relation is defined by exogenous heat rate factors. Heat rate factors vary by plant type and by age of the plant, with new plants associated with lower heat rate factors than existing plants.

Generating plant types considered in the model are listed in Table II-2 along with their associated fuels. The major fuel types are coal, residual, distillate, natural gas, and nuclear. Coal is differentiated by sulfur content and classified as bituminous, sub-bituminous, and lignite. Coal plants are differentiated into five categories corresponding to the coal type which fires the plant. The plants may be equipped either with or without scrubbers. The model allows a certain group of coal plants which do not contain scrubbers (coal acceptable) to burn high sulfur coal while constraining the remaining unequipped plants to burn low sulfur coal.

Also considered is whether plants have the structural ability to convert to alternative fuels. Plant conversions include oil or gas to coal, gas to oil, oil to gas, distillate to gas, and gas turbine to distillate.

Generating plants are classified by plant status as new plants or existing plants. Existing plants by type are considered by the model, as well as plants already committed or deferred, when determining the operating mix of the utilities.

Table II-2

Generating Plant Types and Fuel Uses in the PIES Utility Model

<u>Plant Type</u>	<u>Fuel Uses</u>
Coal	
Coal with SO ₂ scrubbers	Coal—all sulfur levels
Coal without scrubbers	Coal—low sulfur
Committed	
Deferred	
Sub-bituminous	Sub-bituminous
Committed	
Deferred	
Lignite	Lignite
Committed	
Deferred	
Coal Acceptable	Coal—high sulfur
Oil	
Oil Fed Steam	Residual
Simple Cycle	Distillate
Combined Cycle	Distillate

Table II-2 (Continued)

Natural Gas	Natural Gas
Gas Fed Steam	Natural Gas
Gas Turbine	--
Hydro	Nuclear Fuel
Nuclear	--
Wind	--
Solar Thermal	--
Photoelectric	--
Geothermal	--
Fuel Gas	--

Cost entries in the objective function associated with the alternative generating plants differ by plant status. For existing plants, only fuel, operation, and maintenance costs are associated with the use of the plant. Capital costs are treated as sunk costs for existing plants and do not influence the operating decision for these plants. Capital costs, on the other hand, are a factor in determining the mix for newly constructed plants. Hence, capital costs are an entry in the objective function for these plants. The capital cost entry for newly constructed plants varies according to the status of the plants in the initial period of the solution.

Plants already committed prior to solution are treated as existing plants. It is assumed no further capital costs will be incurred for these plants, and their associated capital costs entry is zero. Capital costs are relevant cost entries for the two remaining new plant classifications. For deferred plants, the capital cost entry is reduced 10% below the cost for completely new constructs. This assumes a fraction of the cost has already been incurred for deferred plants and assures that deferred plants are brought into the solution before completely new plants of the same type.

The cost entries in the objective function of the linear program and the capacity equations in the constraint set model the economics behind the operation and construction of generating plants. The linear programming problem determines the cost minimizing mix of generating facilities for the different modes of generation -- base, intermediate, and peak -- subject to existing capacity constraints.

The capacity requirements in each load category are derived by dividing the generation within each load by its associated load factor. The load factors corresponding to base, intermediate and peak load generation are set exogenously at .758, .217, and .26, respectively.

MODEL STRENGTHS

The contributions of the PIES Model to this analysis are its development of demand and supply models, its use of an iterative solution algorithm for integrating between demand and supply, and its linear programming model of electrical conversion and refining which compliment the Brookhaven linear program. In particular, when determining the generation mix in future periods, the model considers the status of existing facilities as well as facilities committed or deferred at the beginning of the solution period.

The load factor adjustments assure that the amount of capacity in the system is responsive to the duration of electricity demand. Capacity per unit of generated electricity will be greater the larger the proportion of electricity allocated to the intermediate generation mode versus base mode, or to peak versus intermediate. Cost minimization results in a generation mix that reflects the duration of demand, as per unit capital costs are balanced against per unit fuel and operation and maintenance expenses. As discussed above, the capital costs relevant to the producer reflect the status of the generating plant facilities (existing, committed, or deferred) at the beginning of the solution interval.

III. GULF-STANFORD RESEARCH INSTITUTE ENERGY MODEL

The Gulf-SRI model is a generalized equilibrium model containing a network of detailed process models which represent the full energy system. Process models simulate the production of primary energy resources, conversion of energy into other energy forms, transportation of energy across regions, transmission and distribution of energy within regions, and end-use demand. A solution of the model produces equilibrium activity levels for each process, prices for the process products and the capacity and secondary material requirements of the processes. In particular, the model projects electricity demands and prices and the generating mix supplying the electricity. The major inputs required by the model include primary resource supply curves (resource supply as a function of cumulative, committed production, and resource price), national and regional economic projections, process technologies, and miscellaneous assumptions regarding technological change, market structures, behavioral lags, and electricity demand load factors. Alternative simulations of the Gulf-SRI model have taken both macroeconomic projections and end-use demand projections (derived through a translator program) as given from the DRI Energy/Economic Model System.

The model is structured as a simultaneous system. For each product, demand is specified as a function of price, production is equated to demand and price is specified as a function of production. (Price is equated to an approximation of short run marginal cost where marginal cost is typically an increasing function of production.) A special network algorithm is employed to find the general equilibrium solution to the simultaneous model system.

The model is dynamic, spanning a range of 50 years at three-year intervals. The equilibrium solution in each period is a short run equilibrium situation. Producers are operating on their short run supply curves and producers' and consumers' demands reflect behavioral lags. Decisions are made for all periods simultaneously, based upon perfect knowledge of all future prices.

Energy demand and supply are modeled for the United States on a regional basis. The disaggregation includes 15 supply regions, six refinery regions, and 11 demand regions. Inter-regional transportation networks allow for transportation of products between regions without implying actual utilization of each link.

The fluctuating nature of electricity demand and the impact of these fluctuations on the generating mix are addressed in the model.

MODEL SCOPE

The network of process models which comprise the Gulf-SRI model follow the conversion and transportation of energy from primary resource form to end-use demand. Figure III-1 represents a section of the model network. The flow of energy in the network is from bottom to top. The circles in the figure represent energy products, boxes correspond to conversion processes and triangles represent transportation or transmission and distribution processes. The figure illustrates:

1. the production of a primary resource and its conversion into an intermediate energy product within the resource supply region;
2. the transportation of the energy product to a refinery region and the refinery conversion;

3. the transportation of the refined intermediate energy product to a demand region for conversion into electricity and;
4. the transmission and distribution of electricity for end use.

Energy need not pass through all the phases indicated in the figure. For example, the energy flow may bypass the refinery process or the electricity conversion process, flowing directly from a resource supply region to a demand region for end-use conversion. Alternatively, an energy product may pass through a series of conversions before reaching the end-use demand market.

The primary resources entering the network are listed in Table III-1 along with the energy end-use demands which are being satisfied (at the end of the network) and the intermediate energy products used in electricity generation.

Table III-1

Energy Supplies and Demands

Primary Resource Supplies

Coal
Domestic Crude Oil
Domestic Natural Gas
Nuclear Fuel
Shale Oil
Hydropower
Imported Oil
Imported Gas
Geothermal
Biomass
Sunshine

End-Use Demands

Residential/Commercial Sector

Electromechanical
Air Conditioning
Space Heat
Miscellaneous Heat (water heating, cooking, drying, etc.)
Rural Heat

Industrial Sector

Electromechanical
Indirect Heat
Direct Heat
Coal Feedstock
Gas Feedstock
Naphtha Feedstock
LPG Feedstock

Transportation Sector

Auto Transport
Truck/Bus Transport
Rail/Transport
Marine Transport
Aircraft Transport

Intermediate Products for Electric Power Generation

Nuclear Fuel
High Btu Gas
Distillate
Residual Fuel Oil

Eastern Coal
Western Coal
Solvent Refined Coal
Methanol
Residue from Coal
Hydropower
Geothermal
Biomass
Solar Power

Within the model network, energy products are transported between resource supply, refinery, and demand regions. The regional detail is listed in Table III-2. Primary resource supply in the U.S. is disaggregated regionally for coal, oil and natural gas. The model considers four sources of coal and nine sources of oil and natural gas. One source of oil shale is considered and points of origin for imported fossil fuels, Canadian gas and nuclear fuels are defined. The supply region for geothermal, biomass, and hydropower is coincident with the demand region.

Intermediate energy products can be transported to one of six locations for refining or to 11 end-use demand regions for electricity conversion. The demand regions include the nine census regions, one U.S. metallurgical coal demand region and one coal exporting demand region.

Table III-2

Demand, Refinery, and Resource Regions

Demand Regions

New England
Middle Atlantic
South Atlantic
East South Central
East North Central
West South Central
West North Central
Pacific
Mountain
Location of U.S. Metallurgical Coal Demand
Location of Coal Export Demand

Refinery Regions

Philadelphia
Gulf Coast Port
West Coast Port
Chicago
South East Port
West North Central

Resource Regions

Great Plains Coal
Interior Coal
Appalachia Coal, Oil, and Gas
South Alaska Oil and Gas
Midcontinent Oil and Gas
Pacific Coast Oil and Gas
Atlantic Offshore Oil and Gas
West Texas/S.E. New Mexico Oil and Gas
North Alaska Oil and Gas
Rocky Mountains Coal, Oil, Oil Shale, and Gas
Gulf Coast Oil and Gas
Point of origin for Imported fossil fuels
Point of origin for Canadian gas
Point of origin for nuclear fuels

1. Primary resource process—models the depletion and pricing of primary energy resources.
2. Simple conversion process—models the technology of converting one energy product into another and the pricing of the converted energy form.
3. Transportation process—models the technology of transporting an energy product across regions and the pricing of the transported energy form.
4. Allocation process—models the allocation of an energy demand among the competing sources of energy supply.
5. End-use demand process—models the demand for end-uses of energy.
6. Secondary industry process—models the impact on the prices of secondary materials due to changes in demand for secondary materials.
7. Complex conversion process—models the technology and economics of a) electric power generation, b) refining, c) auxiliary input conversion or d) joint product processing.

Electricity conversion is modeled differently from other energy product conversions because of the fluctuating nature of its demand and the impacts these fluctuations have on generating capacity requirements. The electricity conversion process combines an electric power load disaggregation process with an allocation process and a simple conversion process. The load disaggregation provides a discrete approximation of the load duration curve. Electricity demand is split into base, intermediate and peak demand. Each category of demand is allocated across the competing sources of electric power generation based upon the load duration characteristic of the demand and the relative costs and capability factors of the alternative means of generation. The electric power conversion processes included in the model are listed in Table III-3.

Table III-3

Electric Power Conversion Processes

Base load hydropower
Intermediate load hydropower
Peak load hydropower
Base load nuclear
Intermediate load nuclear
Base load advanced nuclear
Intermediate load advanced nuclear
Low sulfur/low Btu coal power
High sulfur/high Btu coal power
High Btu gas boiler power
Low sulfur residual power
SRC power
Gas turbine, high Btu gas
Gas turbine, distillate
Gas turbine, methanol
Combined cycle, low sulfur/low Btu coal
Combined cycle, high sulfur/high Btu coal
Combined cycle, methanol
Combined cycle, high Btu gas
Combined cycle, distillate
Shale oil power
Biomass power
Solar base load
Solar non-base load
Geothermal power

The process models which form the Gulf-SRI model can be grouped into seven basic types. The groupings are summarized as follows:

FIGURE III-I
GULF-SRI MODEL
ENERGY NETWORK HIERARCHY

Source: A Western Regional Energy Development Study: Economics,
Volume II - SRI Energy Model Data Base, November 1976.

Each process in the network is modeled by a set of relations which define a simultaneous model system. That is, the relations which model a demand process specify demand as a function of price. Production relations equate production to demand and price relations specify price as a function of production. Because of this simultaneous structure, a special network algorithm was employed. The algorithm requires that the relations describing each process be divided between physical and behavioral relations. Quantities are calculated by the physical relations while prices are calculated by the behavioral relations. The algorithm begins with initial estimates for all prices and quantities in the model for all periods and iterates up and down the model network introduced in Figure III-1 above. An upward iteration (pass) begins with the primary resource processes and a downward pass begins with the end-use demand processes. On an upward pass, prices are calculated using the behavioral relations, the initial estimates for quantities or estimates from the previous downward pass, and solving backward in time. On a downward pass, quantities are calculated using the physical relations of the process, the prices from the previous upward pass, and solving forward in time. The algorithm successively adjusts prices and quantities until all relations embedded in the process models are satisfied.

This process requires that the inputs to a physical relation be:

1. calculated higher in the network algorithm,
2. calculated on an upward pass by a behavioral relation,
3. calculated in a previous time period,
4. exogenous to the model.

Alternatively, inputs to a behavioral relation must be:

1. calculated lower in the network,
2. calculated on a downward pass by a physical relation,
3. calculated in a future time period,
4. exogenous to the model.

Because the classifications of the relations are important to the algorithm, the process discussions identify process relations as physical or behavioral and the inputs to the relations with reference to their origin.

Alternative simulations of the Gulf-SRI Model have treated end-use energy demands exogenously rather than determining these demands within the general equilibrium framework. End-use demands were derived using the DRI Energy/Economic Model System and a translator program. The translator program adjusts the projections from the DRI model system to be consistent with the efficiency, the conservation assumptions and the categories used in the Gulf-SRI model. The procedure replaces the end-use demand process model and the exogenous projections for regional population and GNP with a national/regional economic and energy demand forecasting system. With this adjustment, the Gulf-SRI model becomes a partial equilibrium model within a model system. Iterative solution techniques can be employed to produce consistent solutions between the models in the system.

PROCESS MODEL DETAIL

The processes which model the flow of energy from primary resource form to end-use demand form, combined with the network algorithm completely describe the Gulf-SRI model. The processes which will be discussed in detail are:

1. Simple Conversion Process
2. Primary Resource
3. Transportation Process
4. Allocation Process
5. End-Use Demand Process
6. Secondary Materials Process
7. Complex Conversion Process-Electrical Generation

The complex conversion process for electrical generation is composed of three process types. The first is a load disaggregation process which is unique to the electrical conversion process. The second and third processes are modifications of the simple conversion and the allocation processes.

Processes 1 through 6 are discussed in detail in Appendix C. The complex conversion process, which builds upon the above processes, is discussed below. For an in-depth description of the electrical generation process, the reader should refer to the Appendix in combination with the following.

Complex Conversion Process—Electrical Generation

The complex conversion process for electrical generation determines a dynamic generating mix and the price of electricity given total electricity demand, the load characteristics of the demand, intermediate energy product prices, technology, and behavioral lag and market structure assumptions. The primary resource or simple conversion processes which determine the prices of the intermediate energy forms used in electricity generation are modeled lower in the network. The feedstock prices are inputs to the complex conversion on an upward pass of the solution algorithm. The total electricity demand is determined in an allocation process higher in the network based on the quality adjusted price of electricity relative to competing fuels, the market structure and behavioral lags. The electricity demand is an input to the complex conversion process on a downward pass of the model.

The electrical generation complex conversion process consists of three types of processes:

1. Electric power load disaggregation process
2. Electric power allocation process
3. Electric power conversion process

Each is defined by sets of physical and behavioral relations and is assigned a network location within the complex conversion process. The load disaggregation process is highest in the network, followed by the allocation process and then the conversion process. The two latter processes are modeled similarly to their simple process counterparts. Only the modifications made to the processes will be discussed in this section. (Detailed discussions of the simple conversion process and the allocation process are contained in Appendix C.) The discussion of the process will begin with the load disaggregation process highest in the network, and will work down the network.

Electric Power Load Disaggregation

The physical relations of the process disaggregate electricity demand into three demand load categories—base, intermediate, and peak—while the behavioral relations calculate the price of electricity.

Inputs to the physical relations are:

1. the total electricity demand calculated higher in the network, $q(t)$,
2. exogenous fractions which represent the proportions of total electricity demand classified as base, intermediate and peak load demand, $a_i(t)$, where i = base, intermediate, or peak

Electricity demand in each load category $q_i(t)$, is calculated by multiplying total demand by the corresponding exogenous load fraction, as follows:

$$q_i(t) = a_i(t) * q(t) \quad i = \text{base, intermediate, peak}$$

The inputs to the behavioral relations of the process are:

1. the prices of base, intermediate and peak demand electricity calculated by the electric power allocation process lower in the network, $P_i(t)$, and
2. the exogenous fractions which segment demand into load categories, $a_i(t)$.

The electricity price $P(t)$ is calculated as a demand weighted average of the demand load prices

$$P(t) = \sum_{\text{all } i} a_i(t) * P_i(t) \quad i = \text{base, intermediate, peak}$$

Electric Power Allocation Process

The allocation process allocates the electricity demand for each load category across the competing means of electricity generation based upon the marginal cost of electricity from each means. The electric power allocation process is analogous to the (simple) allocation process. The demand allocations modeled in the process are dynamic. They are based upon both the price and the quality characteristics of the various generating means and they reflect an exogenously specified price sensitivity response and a behavioral lag response. Only two modifications have been made for allocating electricity load demand. First, a demand allocation from peak load demand cannot be made to nuclear generated electricity, and second, all demand allocations to hydropowered electricity generation are exogenously determined.

Electric Power Conversion Process

The electric power conversion process models the technology and economics behind electric power generation. The process is a modification of the simple conversion process. The capacity requirements behind electricity demands are determined in a different manner than the requirements behind other forms of intermediate energy demands. In the electric power conversion process, the generating capacity reflects the fluctuating nature of the demand it is serving. This demand characteristic is not as important a factor for capacity in other energy industries because the industries are able to store their production during periods of off-peak demand and sell from inventories during peak demand periods. The electric power conversion process has also been modified to incorporate the reliability characteristic of the generating facility into the capital cost calculation.

The physical relation for capacity is modified as follows. The capacity requirement, $C(t)$, behind total electricity demand, $q(t)$, is determined by the sum of base, intermediate and peak demands, $q_i(t)$, divided by their associated load factors, $LF_i(t)$. The load factors are exogenously determined.

$$C(t) = \sum_{\text{all } i} \frac{q_i(t)}{LF_i(t)} \quad i = \text{base, intermediate, peak}$$

A corresponding adjustment is made in the behavioral relations which determine the product price for base, intermediate and peak generation. The capital charge component of the price is increased by the reciprocal of the associated load factor. In

addition, the capital cost, $k(t)$, is adjusted by capability ratios. The ratios are derived exogenously, based upon Gerber's method of calculating effective load carrying capacity.

This last adjustment to the capital cost incorporates reliability or availability into the selection of generating facilities by increasing the price being fed to the electric power allocation process.

Model Strengths

The Gulf-SRI model is of particular interest because of the algorithm it employs in order to integrate the energy demand sectors and supply sectors within a single model framework. This contrasts with PIES linked system of models. The supply sectors—energy production, processing, conversion and transportation—of the model are highly detailed. And the solution reflects a dynamic, short-run equilibrium position of the energy sector. The key features leading to this characterization are:

1. The modeling of depletion and economic rent
2. The integration of supply and demand using optimization techniques combined with behavioral lag adjustments and capacity constraints
3. The inclusion of technological change and secondary material industry effects

Shortcomings of the model are being resolved in current model development. One shortcoming of the model is that the demand sector modeling is weak. Recent efforts have linked the Gulf-SRI model with the DRI energy/economic system to expand upon its demand sector coverage.

A second shortcoming of the model is that it assumes perfect foresight of all prices in all future periods as the basis for investment decisions. But again, current model development is aimed at incorporating expected versus actual future prices into investment decision making processes.

IV. THE DATA RESOURCES, INC. ECONOMIC/ENERGY MODELING SYSTEM

The Data Resources, Inc. (DRI) Energy Modeling System consists of a core energy demand model—the DRI Annual U.S. Energy Model and full supply models—the DRI/Zimmerman Coal Model and a refinery linear program (the latter not yet released). The models are linked through iterative solution techniques. The Energy Model System as a whole is similarly linked with the DRI Macroeconomic Model to form a full economic/energy system. The system is illustrated in Figure IV-1. The Energy Model system will first be discussed giving major emphasis to electricity pricing and demand determination, followed by a discussion of the interaction between energy and the economy in the full economic/energy system.

The DRI Annual U.S. Energy Model is an econometric model which can simulate and forecast both regional and sectoral demands for energy in the U.S. under constraints imposed by government policies and restrictions on fuel availabilities. The regions projected in the model cover the nine census regions as defined by the U.S. Bureau of the Census and the five Petroleum Administration for Defense Districts. The model includes over 400 econometric equations which simulate prices, demands, supplies, and movements of energy. In addition to the econometric equations, the model includes over 1,000 identities. Model simulations are based upon forecasts of over 50 economic variables provided by the DRI Macroeconomic Model and regional coal prices determined in the coal model as well as forecasts of approximately 200 exogenous variables.

The degree of exogenous input to the DRI Energy Model characterizes it as a partial equilibrium model. A partial equilibrium model was formulated because of the regulatory bias inherent in energy markets. Government regulation, it was felt, precludes a "free market" general equilibrium solution. To approximate a "regulated" general equilibrium solution, a partial equilibrium model was developed accompanied by presolution calculations, post-solution checks and resolution if necessary. An example of exogenous inputs to the model which are subject to regulatory bias are electric utility capacities. Electric utility capacities enter the model exogenously and contribute approximately half of the electricity price increases over time. A post solution check is made on capacity adequacy by calculating reserve margins. If reserve margins are judged inadequate, capacities are increased. In this case, an adequacy judgement depends upon the modeler's assumptions regarding such regulatory actions as time of day pricing or nationwide power pooling. Both would significantly alter the required reserve margins.

The DRI/Zimmerman Coal Model is a supply and distribution model in which geological, engineering, and economic concepts are integrated to generate forecasts for coal production, prices, and shipments, by quality of coal. The model consists of three basic parts: 1) the exogenous parameters, including regional coal demands from the core energy model, 2) the supply model, and 3) the optimization model. The 18 major bituminous coal producing states are grouped into six supply regions. A transportation network distributes the regional coal supplies to the 13 demand regions of the core energy model.

The DRI Energy Model System was designed as a tool for energy policy analysis and forecasting. Its strengths are in the following areas. First, the system enables one to examine U.S. energy requirements under alternative economic scenarios such as projected by the DRI Macroeconomic Model. Second, the system can simulate the effects on U.S. energy requirements of alternative energy policies. Third, the simultaneous effects of energy policy on both the U.S. economy and energy requirements can be simulated. Fourth, the relative inflexibility in energy usage which results from the slow change in capital goods (homes, factories, and equipment) is reflected.

Fifth, the regional variations in energy usage that result from climatic differences, variations in fuel availabilities, movements in population, location of new industry, regional variations in energy costs, and regulation are taken into account.

MODEL STRUCTURE

The DRI core energy model was implemented so that the users could simulate energy demands by PAD (Petroleum Administration for Defense) or census regions. To achieve this flexibility the states were grouped into 13 regions which completely encompass both regional definition systems. Table IV-1 describes the regional scheme.

Within each region, energy users were segregated into five categories: residential, commercial, industrial, transportation, and utilities. As the model is presently implemented some regional detail has been omitted. Specifically, regional data on the use of petroleum in the commercial, industrial, and residential sectors has been omitted. Similarly, regional demands for coal in these sectors are omitted. These omissions have resulted from problems of data clarity uncovered in the estimation of the model. Efforts to remedy them are currently underway. Table IV-2 summarizes the forecast detail as it is projected regionally or nationally.

The equations of the model have been estimated using data from the following sources: Bureau of Mines, American Gas Association, Edison Electric Institute, Department of Energy, Department of Transportation, U.S. Geological Survey, and data from some of the large coal producing states. The sources used for each fuel and sector are listed in Table IV-3.

The core energy model can be viewed in five parts:

1. Exogenous inputs—national economic and regional demographic projections are exogenous to the model, as are certain price and production forecasts.
2. Regional disaggregation—national economic projections of income, housing starts, employment, auto stocks and other variables are distributed regionally in the regional economic block of the energy model. Industrial productions by two-digit standard industrial classifications (SIC) for manufacturing are distributed regionally in the industrial block of the model.
3. Prices—regional projections of electricity, natural gas, and gasoline prices are developed in the price blocks using a combination of econometric, accounting, and markup approaches.
4. Consumption—unconstrained estimates of the demands for the various energy sources are determined by sector and by region in the consumption block using the economic projections and calculated prices.
5. Balances—1) unconstrained demands for natural gas are balanced against available supplies. In the event of shortages, alternative fuels and electricity demands are affected. 2) Coal demands, supplies, and prices are made consistent through iterative solutions of the energy core and coal models. 3) Electric utilities' generating capacities are checked for adequacy.

FIGURE IV-1

DRI ENERGY/ECONOMIC MODELING SYSTEM

TABLE IV-1

<u>Regional Definitions Used in DRI Energy Model</u>		
<u>Region</u>	<u>Abbreviation</u>	<u>States</u>
New England	NENG	MA, ME, VT, RI, NH, CT
Middle Atlantic	MATL	PA, NJ, NY
South Atlantic	SATL	DE, MD, DC, VA, WV, GA, FL, SC, NC
East North Central	ENC	OH, WI, IN, MI, IL
West North Central	WNC	KS, NB, ND, SD, MN, IA, MO
East South Central I	ESC1	KY, TN
East South Central II	ESC2	AL, MS
West South Central I	WSC1	OK
West South Central II	WSC2	TX, AR, LA
Mountain I	MTN1	NM
Mountain II	MTN2	MT, CO, WY, ID, UT
Mountain III	MTN3	NV, AZ
Pacific	PAC	CA, OR, WA, AK, HI
<u>Petroleum Administration for Defense (PAD) Districts</u>		
<u>Districts</u>	<u>Regions</u>	
PAD I	NENG, MATL, SATL	
PAD II	ENC, WNC, ESC1, WSC1	
PAD III	ESC2, WSC2, MTN1	
PAD IV	MTN2	
PAD V	MTN3, PAC	

TABLE IV-2

Endogenous Variables Forecasted by DRI Energy Model

<u>Fuel</u>	<u>Electricity</u>	<u>Coal</u>	<u>Petroleum</u>	<u>Natural Gas</u>	<u>Nuclear Power</u>	<u>Hydro Power</u>
<u>Sector</u>						
Residential	R			R		
Commercial	R			R		
Household & Commercial		N	N			
Industrial	R	N	N	R		
Transportation	R		N*			
Electric Utilities		R	R	R	R	R
N = National Basis						
R = Regional Basis						
* Except for gasoline, which is regional						

TABLE IV 3

Sources of Data Used in DRI Energy Model						
	Residential	Commercial	Household and Commercial	Industrial	Transportation	Electric Utilities
Electricity	EEI	EEI		EEI	EEI	
Coal				BOM		FPC
Natural Gas	AGA	AGA		AGA		FPC
Nuclear Power						FPC
Hydropower						FPC
Petroleum Products						FPC
Distillate			BOM	BOM	BOM	
Residual			BOM	BOM	BOM	
Kerosene			BOM	BOM		
Liquified Gases			BOM	BOM		
Jet Fuel					BOM	
Gasoline					BOM	
Other			BOM	BOM	DOT	
AGA: American Gas Association BOM: Bureau of Mines DOT: Department of Transportation EEI: Edison Electric Institute FPC: Federal Power Commission						

A flow chart of the DRI Energy Model is included in Figure IV-2.

Exogenous Inputs

The DRI Energy Model forecast is based upon economic projections obtained from simulations of the DRI Macroeconomic Model, regional population estimates derived from 1974 projections of the Bureau of Economic Analysis with revisions based on more recent studies, and a variety of fuel price and fuel supply assumptions. A summary of the model assumptions is contained in Appendix C. Alternative assumptions may be specified and the model resimulated to analyze the impact of these assumptions on energy prices, demands, and supplies.

Regional Disaggregation

National economic projections for income, commercial employment, housing stock, and motor vehicle registrations are distributed regionally in the regional economic block of the Energy Model. The equations which distribute these national forecasts were estimated using temporal cross-section data (time series data for the years 1961 to 1976 pooled for the 13 demand regions) and an error components model. This regression technique explicitly assumes a different intercept for each region with slope parameters common to all regions. The regional effects are treated as random disturbances. This differs from covariance analysis where the regional effects are assumed to be fixed constants, and from ordinary least squares where the regional effects are ignored. The dependent variables in the error component models are expressed as logit shares. This formulation determines projections for each region in a manner which assures that the sums of the regional projections are consistent with the national forecasts.

Regional population projections are exogenous to the model. The regional shares of national disposable income are modeled as functions of regional population shares. Stock adjustment

equations are used to model the regional housing stock shares. "Optimal" regional housing stock shares are expressed as functions of the regions' per capita income and per capita taxes relative to the U.S. averages. Inclusion of the lagged dependent variables in the housing stock share equations reflects the fixed nature of the housing stock with a dynamic adjustment toward "optimal" shares. Regional vehicle registration shares and commercial employment shares are modeled similarly. Each are functions of regional per capita income relative to U.S. per capita income and their lagged value.

An experimental version of the model includes equations for the regional shares of value added by two-digit SIC manufacturing industries. Regional value added shares are modeled as functions of relative wage rates, tax rates, and fuel prices. In this version, total value added rather than population is the leading variable in the determination of the regional disaggregations. Regional population shares are derived endogenously based upon value added shares and their lagged shares. Regional incomes are driven by value added rather than by population.

PRICES

Oil and natural gas prices are determined from the exogenous assumptions regarding imported oil prices and government pricing policies (see Appendix C), nuclear fuel costs are projected exogenously, and coal and electricity prices are determined within the Energy Model System.

Coal Prices

Coal prices are projected within the Energy Model System through iterative solutions of the energy core model and the coal model. Coal demands are determined in the energy core model as functions of coal prices, prices of other fuels, and policy assumptions. The demands are fed into the coal supply and distribution model which generates a set of delivered prices. Iterating between the demand projections of the energy core model and the price projections of the coal model produces a set of equilibrium prices which accounts for interfuel substitutions.

The coal supply model generates cumulative marginal cost functions which are estimated using an geologically-based model of mining. Investment costs for new mines, labor costs,

1. NERLOVE, M., "Pooling Cross Section and Time Series Data in the Estimation of a Dynamic Model: The Demand for Natural Gas," *Econometrica*, 1966, pages 585-612.

FIGURE IV-2

SCHEMATIC DIAGRAM OF DRI
ENERGY MODEL

equipment expenditures, reclamation costs, and federal and state taxes are identified in the model and influence the shape of the supply curve. The costs of coal production are also related to the remaining coal reserves so that the marginal costs of production increase as the remaining reserves decrease.

The production costs along with the regional coal demand projections (from the core model) and exogenous assumptions for transportation costs, scrubbing costs, and regional sulfur emission standards are fed into the optimization model. Based on these inputs, the optimization model distributes coal in a least cost manner to the 13 demand regions.

Electricity Prices

Electricity prices to residential, commercial, and industrial customers are forecast regionally. Each price is derived from an accounting identity which sets the price in each period equal to its price in the previous period plus the increases in the rate base, the non-fuel and maintenance expenses and the fuel costs relative to demand.

The rate base component of the electricity price is based upon the net total utility plant (in current dollars) and an exogenously specified real rate of return on the plant. Net total utility plant includes production, transmission, and distribution equipment. Its value in each period is determined from the previous period's plant, adjusted for depreciation, and the cost of new additions. Nuclear, hydropower, coal, oil, and natural gas generating plant additions in megawatts are projected exogenously. The model calculates the current dollar costs of these additions using the 1976 plant costs per megawatt and inflation rates for electric generating plants.

Non-fuel costs and maintenance expenditures are projected as the product of the number of employees for operation and maintenance of the utility plant and the average wage paid. The number of employees is a function of net total utility plant, while utility wages are forecast to move with wage projections from the macro model. The fuel cost component is set equal to the price of each fuel times the electric utilities' fuel usage. The determination of fuel prices was discussed above, and electric utility fuel demands are discussed below in the consumption sector.

CONSUMPTION SECTOR

Energy demands by the residential, commercial, industrial, and transportation sectors for the energy forms electricity, natural gas, oil, and coal are modeled in the consumption sector. Also modeled are the fuel requirements of the electric utilities. Electricity demands, utility fuel requirements, and electricity prices are modeled simultaneously. A simultaneous model structure is used because of the dependency of price upon fuel cost. Electricity demands are functions of their price, prices are functions of fuel costs, and utility fuel requirements and costs are a result of the generation or demand levels. As demand increases, inefficient plants and higher cost fuels are used, working to increase electricity prices. The higher customer base over which fixed costs are distributed tends to offset the price increases only partially. The price equations were discussed above. The electricity demand equations in all sectors and the utility fuel demand equations are detailed in this section. The treatment of natural gas demands, natural gas availabilities, shortages, and the impact of these shortages on electricity demands are also discussed.

The regional fuel demand equations for electricity and for natural gas were estimated using the error component technique referenced above in the regional disaggregation section. Time series data for the 13 regions were pooled for each demand. With this technique, the estimated equation used to project a particular fuel demand in a particular region was constrained to have the same slope parameters (i.e. price

elasticities, income elasticities, etc.) as in the other regions. Only the constant terms in the equations differ across regions.

Electricity demand equations were estimated regionally for the three major customer groups, residential, commercial, or industrial. Other demands, including railroad and interdepartmental, are forecast exogenously.

Residential and Commercial Electricity and Natural Gas

Residential electricity demands have been modeled to reflect both the residential stocks of electric energy using capital and the household's decision to utilize this stock. The factors in the demand equations which influence utilization are the marginal price of electricity in the 100 kwh to 250 kwh block to residential customers relative to the consumer price index and real disposable income per capita. Electric energy using capital stocks are estimated regionally from projections of the housing stock times the saturation rates for individual electric energy using capital. The saturation rate projections were obtained from a study conducted by DRI for the Electric Power Research Institute, EPRI.²

The study coordinated data from the Census of Housing for the years 1960 and 1970, and from the FPC publication Typical Electrical Bills for Electrically Heated Homes, and Merchandising Week reports. For a list of the residential energy using capital stocks included in the Energy Model, see Appendix C.

The electric energy using capital stock approximations are then multiplied by an associated kwh usage factor, summed and entered in the residential electricity demand equations with the utilization factors.

Residential natural gas demands are modeled similarly. An approximation of the natural gas energy using capital stock in each region is derived from the EPRI/DRI study and is an independent variable in the demand equation along with corresponding price and income variables.

Commercial electricity demands are a function of the average price of electricity to the commercial customer relative to the consumer price index, real disposable income per capita and commercial employment.

Unconstrained demands for natural gas in the commercial sector are modeled in a similar manner. Demands are then checked against supplies to determine curtailments and actual consumption. (See Balances Section below.)

Several improvements have been incorporated into the residential and commercial demand equations in an experimental version of the DRI model. First, all the residential and commercial demands for electricity and natural gas have been estimated as functions of marginal rather than average prices. These marginal prices and associated fixed charges have been developed by aggregating data on individual utility rate schedules to the state level. The resulting demand equations show the demand response to the costs of using additional energy rather than simply the expost relationship between consumption and average revenue.

Second, commercial demand was specified as a function of the square footage of commercial floor space in addition to the price variables. The series on state commercial floor space were developed from F.W. Dodge data on new commercial building under contract. U.S. Treasury data for commercial

2. The Residential Demand for Energy; Estimates of Residential Stocks of Energy Using Capital.

structures in 1970 were used to benchmark the series on new space, resulting in estimates of the stock of commercial floor space in each state for the 1963-75 period.

And third, a natural gas availability variable has been included in the electricity as well as natural gas demand equations. This variable measures the percentage of a state's population that lives in a community serviced by a gas pipeline. With this variable, it is possible to differentiate energy consumers who can substitute natural gas for electricity from those who cannot.

Industrial Sector

Industrial electricity and natural gas demands by region, and coal and oil demands nationally are determined in a three-step process. First, a potential demand for each fuel in each region is determined based on a static relationship between energy demands, industrial output, and relative energy prices. Second, unconstrained fuel demands are derived in a dynamic framework based on the potential demand projections. Third, unconstrained industrial natural gas demands are balanced against natural gas availabilities after higher priority demands have been satisfied. Demands are adjusted in the event of curtailments.

The potential demand equations serve to 1) distribute national production by two-digit SIC manufacturing industries regionally, 2) translate the index of industrial production into an electricity, natural gas, oil, or coal requirement, and 3) reflect interfuel substitutions due to changes in relative fuel prices.

The potential fuel demand variables are used to drive actual industrial fuel demands. Unconstrained demands are modeled using a dynamic stock adjustment specification because of rigidities in adjusting to potential demands. In the short run, actual energy demands adjust only partially to changes in potential demands. Long run elasticities on the potential demands have been constrained to one so demands will ultimately reflect the full changes in the potential demands. The industrial demands for electricity and natural gas are projected regionally using the error component technique. Regional data was pooled for the years 1961 to 1976 to estimate the regional electricity demand equations. Data was pooled only for the years 1961 to 1969 in estimating the equations for the unconstrained demands for natural gas, since natural gas prices were not market-clearing after 1969. Coal and oil demands are projected only nationally and in a residual fashion; that is, the total demand for energy is determined, and once the natural gas and electricity demands are derived, the residual is allocated to coal and oil. Total fuel demand is modeled dynamically. Demand adjusts to a weighted sum of the potential fuel demands (where the weights reflect relative end-use fuel efficiencies) and to the price of energy relative to the prices of the other factors of production. The relative price term captures the substitution between energy and capital and labor in industrial production. The split between coal and oil is based on the potential demands for coal and oil in a dynamic framework.

Utility Demand for Fuels

Electric utility generation requirements in each region depend upon the total electricity demand projections discussed above and exogenous assumptions regarding the generation-to-demand relations in each region. The generation-to-demand relations in each region are forecasted based on historical transmission efficiency factors and interregional electricity supply/demand activities. Utility fossil fuel requirements are determined as the difference between generation requirements and the amount of electricity generated from nuclear and hydro sources. Nuclear and hydro generation are determined from plant capacity projections obtained from utility surveys and exogenous assumptions regarding the utilization of the plants.

The mix of fossil fuels used by electric utilities is largely determined by the mix of the fossil fuel generating capacities and by energy policy assumptions. The amount of natural gas demanded by utilities for peaking is exogenous to the model. Natural gas demands for nonpeaking purposes depend upon gas availabilities (after residential, peaking, raw material, and commercial demands have been satisfied) and the modeler's assumptions regarding the proportion of the availability which is to be allocated to electric utilities. Fossil fuel demands not met by natural gas are satisfied by oil and coal.

The proportion satisfied by coal is linked directly to the coal capacity. The utilization of the coal capacity (coal plant factor), which defines the actual coal consumption, varies (up to a specified maximum plant factor) in response to relative coal/oil prices, implied oil plant factors and the proportion of the electricity generation met by nuclear generation. A decline in coal prices relative to oil increases the utilization of the coal plants in the model as does an increase in the implied oil plant factors. A higher proportion of nuclear generation, on the other hand, reduces the utilization of the coal plants. Since both nuclear and coal plants are typically used for base load generation, more nuclear generation reduces the need for coal in base load generation and hence the demand for coal. The utility fuel demand sector of the model is illustrated in Figure IV-3.

BALANCES

The natural gas and electricity generation balance are discussed in this section. Coal price and demand balances were discussed previously in the coal price section.

The structure of the Energy Model recognizes that regulated natural gas prices, below market-clearing prices, can result in natural gas demands that exceed supplies. An allocation scheme is built into the structure which assigns priorities to the various natural gas users. Low-priority users in each region receive their full unconstrained natural gas demands only if the availability of gas in the region, after all demands by higher-priority users have been met, is sufficient to meet their demands. If availabilities are not sufficient, actual consumption is set equal to the remaining availability, falling short of unconstrained demands.

The natural gas users, listed in order of their priorities, are:

1. The residential sector
2. Electric utilities - peaking purposes
3. The industrial sector - raw material uses
4. The commercial sector
5. Electric utilities - non-peaking purposes
6. The industrial sector - fuel and power uses

The available natural gas is first allocated to the residential sector, to electric utilities for peaking purposes, and to the industrial sector for raw material uses. Natural gas is then allocated to the commercial sector. At this point, the model checks unconstrained demands in the commercial sector against the remaining supplies. If supplies are insufficient in a region, commercial demands are constrained. Actual consumption of natural gas by the commercial sector in each region is set equal to the lesser of the remaining availability and the unconstrained demand.

If natural gas is still available after satisfying all of the above demands in the region, a portion of the remaining availability is allocated to the electric utility sector for non-peaking purposes. The remaining proportion can then be allocated to the industrial sector for fuel and power uses. As with commercial natural gas demands, the unconstrained industrial demand may exceed this remaining supply. Actual industrial consumption is set equal to the unconstrained demand if supply is sufficient, otherwise to the remaining supply. Curtailments are defined as the difference between unconstrained and constrained demands.

FIGURE IV-3

ELECTRICITY SUB-MODEL

Expected natural gas curtailments in the industrial sector are calculated from prior period differences between unconstrained and constrained natural gas demands using an adaptive expectations approach. Potential natural gas demands are reduced by the expected curtailment measure while the other potential energy demands are increased by a proportion of expected curtailments. The proportions of the expected curtailments allocated to electricity, oil and coal are specified exogenously. Actual energy demands are affected by the adjustments to the potential demands. In the short run, the impact on actual demand is only partial, while in the long run, actual demand is altered by the full amount of the adjustment.

The electricity generating facilities in a region are exogenous inputs to the model and therefore are not influenced within the model framework by the electricity demands projected in the model. To assure consistency between electricity demand projections and the facilities which generate this electricity, post-solution checks are made. These checks also bring consistency to the electricity demand and price projections, since prices reflect the rate base. The post solution checks involve the calculation of reserve margins for each region based upon the regions electricity generation requirements and regional load factor. If reserve margins fall well above or below target levels, the exogenous capacity projections are reevaluated. Capacity projections can be increased by the modeler, taking lead times for the various facilities into consideration, if reserve margins are judged too low. Alternatively, if reserve margins are judged to be high, the modeler may be able to reduce capacity if new additions could be postponed or cancelled. After making capacity adjustments, the model must be restimulated and reserve margins and capacity evaluated again.

MACROECONOMIC LINK

Energy demands are influenced by the economic environment while at the same time the costs associated with these demands significantly impact the economic environment. In DRI's modeling efforts this simultaneity between energy and the economy is dealt with through iterative solutions of the DRI Energy and Macroeconomic Models, to insure the energy projections are consistent the Macroeconomic Model and the macro projections are consistent with the Energy Model.

The economic factors simulated in the Macroeconomic Model and inputted to the Energy Model will first be summarized, followed by a discussion of the feedback effect which energy has on the Macroeconomic Model. (Note: National economic projections are obtained from the Macroeconomic Model and distributed regionally in the Energy Model. The distribution process was explained above.)

The macroeconomic variables which influence energy demands, particularly electricity demands, are

1. Production indexes (by two-digit SIC manufacturing industries)
2. Income
3. Housing stock/starts
4. Employment
5. Price and wage indexes

Production indexes play a principal role in the determination of industrial energy demands. Income and housing projections drive residential energy demands, while commercial employment is important in deriving commercial energy demands. The overall price level and the wage rate are important in evaluating the real cost of energy.

Projections from the Energy Model in turn are significant in determining the above economic forecasts. In the Macroeconomic Model, a change in energy prices shifts relative prices as well as affecting the overall inflation rate. Energy price and oil import changes alter final demands with simultaneous changes in production, income, wage rates and the factor proportions used in production. Energy supply is important for the calculation of potential GNP made outside the model. The exogenous projection for potential GNP is the benchmark for all long-term aggregate demand forecasts.

ENERGY PRICE CHANGES

The wage-price sector of the Macroeconomic Model contains 11 behavioral equations for wholesale prices, behavioral equations for wages and total compensation, one equation for productivity, 19 equations for GNP deflators for the various components of final demand and three equations for components of the consumer price index. Prices are modeled using a stage of processing approach. At each stage of processing, the prices from the previous stage provide an estimate of material costs. Labor costs adjusted for productivity gains are added to the material costs in each successive stage to form the cost component of the price. The rate of inflation in turn feeds back into wages.

Energy costs affect prices beginning in the first stages of processing. Changes in energy prices alter both the overall inflation rate and relative prices.

Inflation is modeled to have a real effect on the economy. It impacts consumer attitudes. This is reflected in the model by a consumer sentiment index which enters into the final demand equations. Interest rates are also responsive to the inflation rate. A rise in interest rates has a negative effect on housing and further influences on some of the final demand categories.

Final demand prices change relative to one another when fuel prices rise as a result of the different fuel intensities of their production processes. The DRI macro model captures the relative price changes due to differences in the production mix through the use of a fixed-coefficient Leontief-matrix of industry production. The elements of the matrix are used to weight the factor prices in each output price equation. Factor prices are included for 12 wholesale price indexes, including the wholesale price index for fuel, wage rates, and capital costs.

The changes in the relative prices of the final demands affect the demands for goods and services. The impact on demands depends not only on the amount the various prices change but also on the price elasticities of the demands. Econometrically estimated demand equations which model final demands as functions of relative prices estimate the price elasticities which define the direct price effect on demands. (Demands are also functions of income and foreign production indexes along with other determinants particular to the demands.) Simulation of the model with alternative prices reveals the total price effect and shows price elasticities to vary considerably across the demand categories. Of particular interest are the price effects in the factor demand equations for capital and energy. The factor demand equations for capital in the Macro Model and energy in the Energy Model capture shifts between energy, capital and labor as the relative prices of these factors of production change.

Also of major importance is the income effect on demands. Higher energy prices increase inflation. As noted earlier, inflation reduces real economic activity and the reduction in demands directly affects the income side of the account. The multiplier effect is introduced through the simultaneous interaction of the demand, production and income sectors as lower incomes further impact demands. Table IV-3 illustrates the effects of a 10% incremented increase in the wholesale price for fuel and power in 1979 on various prices, demand categories, unemployment and other economic indicators.

Oil Import Changes

A change in the oil import assumption in the Macroeconomic Model affects the trade balance. Increasing oil imports for an extended period of time without a corresponding increase in exports or reduction in other import categories has a significant impact on the economy. Table IV-4 shows the effect on the trade balance, real GNP, industrial production, unemployment, and profits due to a 1 million barrel per day use in petroleum imports sustained over the 1979 to 1983 period as simulated by the Macro Model.

TABLE IV.4

Simulation of the Macroeconomic Model
Higher Energy Prices

	1979	1980	1981	1982	1983
Fuel Index					
Control	3.718	4.247	4.674	5.068	5.488
Higher Energy Prices	4.089	4.653	5.123	5.550	6.000
% Difference	10	9.6	9.6	9.5	9.3
Real GNP (billion \$)					
Control	1445.2	1513.5	1571.3	1620.9	1690.7
Higher Energy Prices	1442.2	1505.7	1562.7	1612.5	1683.5
% Difference	-.2	-.5	-.5	-.5	-.4
Industrial Production Index					
Control	1.502	1.591	1.657	1.715	1.816
Higher Energy Prices	1.493	1.573	1.638	1.696	1.800
% Difference	-.6	-1.1	-1.2	-1.1	-.9
Unemployment Rate					
Control	6.0	5.7	5.4	5.5	5.2
Higher Energy Prices	6.1	5.8	5.6	5.7	5.3
% Difference	.8	3.3	4.0	3.9	3.4

TABLE IV.5

Simulation of the Macroeconomic Model
Higher Fuel Imports

	1979	1980	1981	1982	1983
Real Fuel Imports (billion \$)					
Control	48.8	54.0	60.2	66.7	73.9
Higher Fuel Imports	55.2	61.4	68.3	75.4	83.1
% Difference	13.1	13.6	13.3	13.0	12.6
Real GNP (billion \$)					
Control	1445.1	1513.5	1517.3	1620.9	1690.7
Higher Fuel Imports	1441.8	1508.6	1566.4	1617.5	1688.2
% Difference	-.2	-.3	-.3	-.2	-.1
Industrial Production Index					
Control	1.502	1.591	1.657	1.715	1.816
Higher Fuel Imports	1.496	1.581	1.649	1.709	1.813
% Difference	-.4	-.6	-.5	-.3	-.1
Unemployment Rate					
Control	6.0	5.7	5.4	5.5	5.2
Higher Fuel Imports	6.1	5.8	5.5	5.6	5.2
% Difference	1.0	2.2	2.4	1.8	1.3

V. DRI LOAD FORECASTING SYSTEM

A. MODEL SCOPE

The DRI Load Forecasting System (DRI/LFS) is a generalized framework utilized jointly by DRI and its utility clients to develop a load forecasting system for each utility's particular service area.* The system uses DRI's Macroeconomic Model and Energy Model System in combination with customized modeling to develop a series of models capable of projecting an individual utility's:

- Service area economic outlook
- MWH consumption
- MW demand
- 24-hour load profile

The models are used to test the impact of different economic scenarios, government policies, conservation and load management programs on service area consumption and demand.

A general schematic of the forecasting system is provided by Figure V-1. There are three major components to the system. The first is a set of DRI services that provide a link to the national economy and energy market. The second component consists of a service area economic model, measures of weather conditions, energy prices and supplies and technological parameters that together define the underlying determinants of local electricity requirements. The last component is a set of utility specific models. Each of these components is briefly described below:

1. Model Links

The Load Forecasting System obtains projections from both the DRI Macroeconomic Model and the Energy Model System discussed in the previous section. Macroeconomic projections range from GNP and its components to detailed industrial concepts, providing forecasts of production, investment, and employment by major manufacturing category. The projections are fed through the service area economic model to measure their impact on the utility's local economy. The Energy Model System is used within the load forecasting system to provide information about energy prices and supply constraints in the census region within which the utility operates.

2. Underlying Determinants

As noted in Figure V-1, there are three major categories of information that feed the consumption and demand models of the Load Forecasting System. The service area economic model provides the first category of information, an outlook of the major economic parameters of the local area. The data base utilized in its development follows the utility company's service area geographical boundaries as close as published data allows. The model is designed to support a detailed forecast of energy and demand requirements; its outputs include projections of two-digit SIC production and employment for the industrial sector, detail about nonmanufacturing employment and retail sales, population (by age group), and personal income, as well as other pertinent economic indicators.

The impact of weather conditions on load is measured within the model. In the forecast, weather conditions are exogenously entered and provide the second category of information. While normal conditions are usually assumed for base case forecasts, the impact of alternate weather patterns on requirements can be tested within the system.

Energy prices, supply constraints and technological advancements are exogenously input to the system, providing the third major category of information. Projections from the DRI Energy System, as mentioned above, provide an assessment of the energy outlook for the census area encompassing the utility service area. The regional assessment is derived from a national perspective, in the DRI Energy System.

3. Utility Specific Models

The utility specific models used in the load forecasting system forecast a) MWH consumption, b) MW demand, and c) 24-hour load profiles at a monthly, quarterly, seasonal, and/or annual frequency. The frequency used by an individual utility varies depending on the available data and forecast requirements of the individual utility. DRI, in its application of LFS, utilizes data at either a monthly or quarterly frequency to assure the most reliable statistical results.

The MWH consumption models are developed by class of service, namely, residential, commercial, industrial, agricultural, wholesale, street lighting, and whatever other sector rounds out total consumption for the utilities. The forecasts of each sector are developed by analyzing the major subsectors of each group. For example, in forecasting industrial sales, the MWH consumption of each two-digit SIC industry is analyzed.

The MW demand model projects system peak at either a seasonal or monthly frequency. In arriving at a peak forecast, the sector contributions to the system peak are explicitly modeled.

Finally, the load shape model provides a forecast of average weekday 24-hour load profile at a seasonal or monthly frequency. The model output includes an assessment of the contribution of each class (or subclass) to the system load shape.

The design and detail of the peak and load shape models vary widely across utilities, depending upon the availability of load data. The lack of sufficient load data and the importance of the sector breakdown to forecasting the system peak and load shape have led to the flow of the models described in Figure V-1. That is, while optimally one would like the flow to be from hourly loads, to peak demand and finally MWH consumption, most utilities have only limited information on sectorial loads at an hourly frequency. Yet the impact of the underlying determinants described in the previous sections is known to vary significantly across sectors. In order to properly account for the impact of these factors, the linkage must be made at a disaggregate level. The linkage is made with sectorial sales data. This information, in combination with load research data and the underlying determinants described above (for example: hourly weather conditions), is then used to determine the system peak and shape. The analysis uses the MWH detail and statistical inference to arrive at a breakdown of the consuming sector's contribution to the hourly system load.

B. MODEL DETAIL

This section will review the model detail of the service area economic model and the utility specific models developed within LFS. In doing so, 1) a typical output of each will be given, 2) the major inputs and interactions will be discussed, and 3) the major strengths and weaknesses of the models will be reviewed.

* The Load Forecasting System was developed by the Utility Consulting Group at Data Resources, Inc. (UCG/DRI).

FIGURE V-1
FORECASTING SYSTEM SCHEMATIC DIAGRAM

1. Service Area Economic Model

The role of this model within the system is to provide an assessment of economic and demographic growth potential of the area served. As such, the data base utilized follows the geographical definitions of the utility's service area as closely as possible. For most utilities, this requires the collection of county and labor market area data from state and federal sources. In some cases this component is of two parts; first, a model covering a larger geographical area within which the service area lies, and second, a model of the utility's service area. This latter approach is utilized when the utility's service area is too small to capture the economic activity within an econometric framework. In this case, the larger geographic model is linked to the DRI Macro Model and the service area economic model to this. With this two step process LFS is assured of properly accounting for economic causes and interactions while satisfying geographical exactness.

A typical output of the service area economic model is provided in Table V-1. Output A highlights the detail that is pursued when an entire state or greater geographical area is modeled; Output B refers to the output provided by most substate efforts. The difference is a function of data availability.

The service area economic model consists of four major sectors: 1) employment, 2) wages and prices, 3) income, and 4) demographics. Figure V-2 provides a simple schematic of the interaction of these sectors. The state models, while providing more detail, are designed along the lines of this basic framework.

The employment sector consists of manufacturing and non-manufacturing subsectors. The manufacturing employment equations provide the major linkage between the U.S. economy and the service area. Manufacturing employment for each SIC manufacturing industry in the service area is modeled as a function of the corresponding industrial production index for the industry and locational parameters. These parameters include: a) local industrial mix, b) relative wages c) relative energy costs and d) relative corporate tax rates. The employment forecasts, in combination with the productivity measures by industry from the DRI Macro Model, provide the basis for local production forecasts.

The nonmanufacturing employment equations are developed by considering a) the overall growth in the service industries, and b) the local growth in population and income in the service area. In the contract construction employment equations, additional consideration is given to the local housing and nonresidential construction activity.

The wage and price sector provides forecasts of the local CPI and average hourly earnings for the manufacturing sector. The local CPI is tied econometrically to national movements in prices provided from the DRI Macro Model, and to relative cost factors of the area to the nation, such as energy and wage costs. The wage equation, similarly, is linked to national wage movements, differentiating between the two by including a measure of the cost of living (CPI's) and labor market tightness in the area relative to the U.S.

The personal income sector projects per capita personal income, and when the data permits, a breakdown in income into its components; wages, rents, proprietor's income, transfer payments, etc. Wage and salary disbursements are modeled as a function of local employment and average hourly earnings provided through the wage and price sector. The other components of income are for the most part based upon corresponding per capita projections from the DRI Macro Model.

The demographic sector analyzes the growth in population by analyzing birth, deaths, and immigration. Births and deaths are obtained by making an exogenous assessment of birth and

death rates and applying these to the population figures. Migration is forecasted through an econometric equation which relates net migration into the area to employment opportunities and wages in the area relative to the nation. In addition to total population, age breakdowns of the population are forecasted based on survival rates of the different age groups and the historical mix of migration across age breakdowns.

2. MWH Consumption Models

The MWH consumption models are the heart of LFS. Currently, sales data provide an individual utility with the most continuous data set on their customers. A sample of the model output provided in Table V-2 illustrates the detail available and utilized in this portion of the System. The final breakdown of sales depends upon data availability and the stability of the estimates. The three major consuming sectors: residential, industrial, and commercial, are analyzed below, followed by a brief review of the other models.

Residential

The residential model consists of three major components:

- customers,
- major residential appliances, and
- usage per customer.

The customer component determines the total volume of customers and the split of these customers across the different residential rates. For example, customer forecasts are broken down into all-electric, water heating, and general service categories. The total customer equations are developed by linking the volume to population and household wealth, both long-term determinants of household formation. The population of the 21 and over age group is utilized, as it represents the population of house-owning age. A stock-adjustment model is utilized when at all possible in order to better capture the dynamics of the local housing market. The data available for this kind of analysis varies significantly across utilities, with some keeping track of monthly new dwelling units by dwelling type and others having only a record of total customers. Thus, the detail and statistical properties of these models differ significantly across models developed within this framework. Given the number of new customers, the split among the different rate groups is estimated as a function of relative fuel costs and utility promotional activity.

The appliance component consists of a set of equations designed to forecast the long-term saturation rate of major residential appliances. The database of appliance stock is developed for the utility's service area based on a combination of the individual utility's residential saturation surveys and census statistics. A logit formulation is used to constrain the estimates within saturation bounds. The growth in saturation is related to per capita income, price of appliances, number of new households, average number of people per household, and other relevant demographic and economic parameters. In the case of appliances with alternative fuel sources, the relative price of fuels is considered. When subclasses of customers are to be analyzed, relative saturation rates across customer types are analyzed.

The final component, residential usage per customer, contains equations for each of the customer breakdowns provided in the customer component. The growth in usage per customer is addressed by including both short-term and long-term determinants of consumption. The growth in the stock of energy using appliances provides the long-term indicator. A weighted appliance index is developed from saturation rates of the major appliances. Each is weighted by its average annual usage. Short term indicators reflect the utilization of the energy using appliance. They include the real price of electricity, per capita income, household characteristics, when available, and weather conditions. The weather terms are weighted by the number of weather sensitive end-use units to

Service Area Economic Model Output

State Model

Output A

1. Business Activity

- . Gross state product
- . Value-added manufacturing

2. Wages and Prices

- . Average hourly earnings
- . Consumer price index

3. Personal Income

- . Wage and salary disbursements
- . Other labor income
- . Property income
- . Proprietors income
- . Transfer payments
- . Contributions to social security

4. Consumption and Investment

- . Retail sales
- . Housing permits
- . Production manufacturing (by 2-digit SIC)

5. Employment

- . Manufacturing (by 2-digit SIC)
- . Non-manufacturing (by service categories)

6. Financial

- . Deposits - F.R.B. Banks
- . Loans and discounts - F.R.B. Banks

7. Fiscal

- . State government receipts
- . State government expenditures

8. Demographics

- . Total population
- . Age breakdown (0-20, 20-64, 65+)
- . Labor force
- . Rate of unemployment

Substate Model

Output B

1. Manufacturing

- . Production activity (by SIC)
- . Employment (by SIC)
- . Wage rate

2. Nonmanufacturing

- . Employment (by SIC)
- . Retail sales

3. Prices

- . Consumer price index

4. Personal Income

- . Total
- . Major component

5. Demographic

- . Total population
- . Age groups
- . Births and deaths
- . Migration
- . Labor force

FIGURE V-2
SCHEMATIC DIAGRAM OF
SERVICE AREA ECONOMIC MODEL

Table V-2

DRI Load Forecasting System

MWH ENERGY MODEL

OUTPUT

1. RESIDENTIAL

- Customers (by type)
- Stock of appliances
- Usage per customer (by type)
- MWH sales

2. INDUSTRIAL

- MWH sales—by major SIC or rate classification
- Customers

3. COMMERCIAL

- MWH sales—by major SIC or rate classification
- Saturation of electric heat

4. WHOLESALE

- MWH sales by class of service

5. STREETLIGHTING

- Number of lamps
- Wattage/lamp
- MWH sales

6. COMPANY USE AND LOSSES

- MWH

allow for the changing impact of weather. Residential sales is then obtained by multiplying the customer forecast by the usage projections and summing across residential customer types. The models are estimated with either monthly or quarterly data. The monthly data is preferred so that the impact of weather can be sufficiently measured.

The residential sector of the system is the most detailed and end-use oriented. As such, it provides the most flexibility in analyzing the impact of load management and conservation programs.

Industrial Models

The industrial models forecast electricity sales to each of the major manufacturing groups within a particular service area. The classification of groups is based on a utility's available industrial data. To the extent possible, the breakdown is done at the two-digit SIC level with three- and four-digit groupings used for large sectors when the data is available (e.g., for chemicals). The difference between total industrial sales and the two-digit detail is modeled as an aggregate. Not all two-digit industries are modeled separately, since the size of some are too small to allow confidence in the estimated parameters. An aggregate approach to these small groups has been found to lead to better statistical results and forecasting accuracy.

In developing the industrial models, the LFS considers four major factors:

- production activity,
- factor substitution,

- technological change, and
- conservation.

A measure of production activity is projected for each of the major manufacturing groups in the geographic service area. The models are developed based on an expected proportional relationship between industrial production and electrical sales. The remaining factors and a minimum level of usage are included in the analysis to account for the deviation in that relationship.

The substitution of alternative energy sources for electricity or labor for electricity in the industrial sector is considered. Substitution is included by measuring the response to relative price changes. However, prior to the inclusion of these relative prices in any individual utility's model, two issues are addressed: 1) the technological feasibility of substitution for the industry group being considered, and 2) the availability of alternative fuels within the service area once they are considered technologically feasible.

Technological change is defined to include voluntary advancements as well as government safety and health standards which require additional/less usage per unit of output produced. In undertaking any historical analysis of sales, each industrial group is reviewed for explicit changes in technology. In the forecast mode, known changes in technology are factored into the forecast.

In addition to this customer specific analysis, the general trend in capital deepening is captured through cost of capital and other similar variables.

Conservation is considered to arise for two reasons: 1) to minimize the dependence on foreign energy supplies, and 2) to minimize the impact of rising energy costs. In order to account for the first, an effort is made to obtain information of the major programs undertaken in the different industrial groups. Where explicit information is available, it is used; otherwise a conservation pattern is depicted over the interval, allowing the statistics to measure the impact. To account for the second, the real price of electricity is included. The price term is developed from the individual utility's rate schedules.

One final consideration given, in developing these models, is self-generation. To the extent possible, information on self-generation is collected when it accounts for a significant portion of total use.

In addition to the specification outlined above, a methodology is being developed to forecast total energy requirements for the industrial sector within a given service area. This approach, which is highly sensitive to data availability, is expected to improve the model's ability to address substitution and supply constraint issues.

Commercial Models

The commercial models developed within LFS differ substantially in their detail because of the wide variation in available information for this sector across utility companies.

Several breakdowns have been developed within this subsector of the LFS:

- sales by one-digit SIC (e.g., retail trade), and
- general service and all-electric.

The breakdowns are dependent upon the historical billing breakdown of the individual utility. In all cases the following issues are considered:

- sector growth,

- energy substitution, and
- conservation.

The service area economic models provide, through their detailed nonmanufacturing employment sector, an indication of sector growth. When several nonmanufacturing categories are modeled, the employment in each category is weighted by the average kwh use per employer and this weighted average is entered in the equation. Though no explicit account is taken of technological change in the model due to data limitations, the kwh use per employee weights are adjusted to reflect any explicit assumption of technological change.

Energy substitution is handled in one of two ways. When saturation data is available for the major commercial uses, the saturation rates are modeled as functions of the price of electricity relative to alternative fuels and the individual utility's promotional efforts. The saturation rates are then used to drive MWH sales in the model. When saturation data is not available or only partially available, the price of electricity relative to alternative fuels is entered directly into the MWH sales equations.

The impact of conservation is handled in this sector in the same way as it is handled in the industrial sector, described above. A conservation pattern, which represent the efforts to minimize foreign oil imports, and the real price of electricity to the commercial sector are included.

Other Models

In addition to the three major sectors, LFS contains models of the remaining sectors necessary to arrive at total sales. The models are in part econometric and in part identities driven by exogenous assumptions. The sectors considered include wholesale, street lighting and company use and losses. Their relative importance differs from utility to utility, with the wholesale sector being a large percentage of total load in the southern utilities and of minor importance in most utilities modeled in the northeast. The breadth of the models developed tends to vary with their percentage contribution to the system load. The methodology of each is briefly reviewed below.

The wholesale sector is composed of sales to cooperatives and municipalities. The problem is broken down into: 1) determining the energy requirements of the co-ops and municipalities being served, independent of who provides the power, and 2) given their total requirements, what percent of that load will be supplied by the generating utility. The first issue is addressed by forecasting the co-ops' and municipalities' residential, industrial, and commercial sales. A modified form of the methodologies reviewed above is utilized. The percent of that load to be served by the generating utility is an exogenous assumption to the model. The assumption is usually based on historical percentage and expected contractual arrangements.

Street lighting sales have been modeled in formats as simple as relating sales to overall economic or demographic measures of service area growth and urbanization, to models which forecast the number of lamps by type (incandescent, mercury vapor, high powder sodium), and the average watts per lamp type. The number of lamps are related to measures of service area growth, the wattage figures are provided exogenously.

Company use and losses are exogenously included, for the most part being made a constant percentage of recorded sales.

3. MW Demand Models

The MW demand models forecast hourly demand at the "dominant hour". The dominant hour is defined as the hour at which the maximum number of system peaks occurs for the period (e.g., season) being studied. This forecast is then

combined with the output of the 24-hour load profile model (see below) to determine the system peak.

The MW demand model is developed by first determining the average hourly loads for each of these major sectors and sector breakdowns:

- (1) Residential (by appliance when available)
 - base
 - weather sensitive
- (2) Commercial
 - by sector (when available) and/or
 - base
 - weather sensitive
- (3) Industrial
 - by SIC groupings (based on similarity of load shapes)
- (4) Wholesale
 - same groupings as (1) - (3)
- (5) Street Lighting, Company Use & Losses
 - totals

Load research studies are utilized to determine the relative contribution at the dominant hour to the average hourly usage for the sector breakdowns. These studies are usually available for a subset of the above sector breakdowns. The information they provide is utilized to aggregate some of the sector breakdowns to reduce the number of parameters to be estimated. For those sector breakdowns for which load research studies are not available, their relative contributions are inferred from the estimation results.

The approach provides the user with several points for analysis. First, the contribution of the major subsectors to MW demand is included. Second, the model incorporates load research studies which can be updated when new studies become available. Third, it attempts to endogenize the changing contribution of the sectors to MW demand. Even when endogenizing is not possible, the modelers are able to exogenously affect a change.

4. 24-Load Profile Model

The load profile model is designed to project the average weekday 24-hour load shape for the winter and summer seasons. The methodology utilized in developing these models builds from the work utilized in the MW demand model. An estimate of average hourly load for each of the subsectors is utilized as the basis for the estimation. Spline functions are employed to measure the contribution of each subsector at each of the 24-hours relative to the average hourly contribution. These contributions are not considered fixed but rather a function of hourly weather conditions as well as economic and demographic characteristics.

The equations are estimated in linear form over weekday hourly data within the season being studied over a 10- to 17-year history.

The 24-Load Profile Model provides a forecast of the load shape. Combining this forecast with the forecasts of the dominant hour MW demand model provides the necessary information to forecast the peak demand and the height of the load curve at each hour of the day.

CONCLUSION

Regional power system planners need to project the electricity demands within their service areas, the load characteristics of their demands, the constraints — capacity, technological, regulatory, financial, etc. — under which they will be operating and the minimum cost means of reliably satisfying their demands subject to their constraints. These projections will be influenced by a wide range of factors. The region's economic activity, the national economy, the price of electricity, and the prices of competing fuels are key factors. Electricity prices, in turn, will depend upon the price of fuels, capital costs, and energy technologies, while fuel prices will depend upon future resource supply technologies and production factor costs.

In the introduction of this study, an integrated system of models was suggested as a means of modeling the interrelationships between these factors and obtaining the projections required by regional power system planners. The models reviewed in the chapters which followed were developed to analyze various aspects of energy and electricity. They vary in scope and would complement each other in an integrated system of models.

- The DRI Energy System, the PIES Model, and Gulf-SRI Model were designed to give consistent regional projections for energy prices, supplies and demands.
- The DRI models contain detailed demand sectors which base demands projections upon regional and national economic factors.
- The BESOM, PIES and Gulf-SRI Models are detailed supply models which incorporate the technologies

behind the conversion of energy from a primary resource to an end use demand in an optimization or equilibrium framework.

The DRI Energy System, the PIES and Gulf-SRI Models contain geologically and engineering based resource supply models.

The role of each model in an integrated model system and its particular strengths are discussed in each chapter. When developing an integrated model system for regional power system planning, one should build upon these strengths. The appropriate level of detail should be defined for each model in the system and consistency between models should be maintained.

A three-tier system of models is suggested. The first tier consists of a macroeconomic model with general energy-economic relationships such as the DRI model. The model is required to simulate the economy and to provide the economic projections for the energy models in the system. The second tier includes a subnational, full energy system model which is used to obtain regional energy prices, demands and fuel availabilities which are consistent from a national perspective. The subnational model should try to incorporate the demand sector detail in the DRI Annual U.S. Energy Model, the primary models or techniques of the Gulf-SRI, the PIES, and the BESOM models. The third tier contains electricity models which model electricity demand and supply for the regional power systems service area. Demand modeling can build upon the DRI Load Forecasting System, while BESOM and the electricity supply sectors of the Gulf-SRI and the PIES models could provide a basis for service area supply models.

ELECTRIC POWER SYSTEM PLANNING: THE VALUE OF ENERGY SYSTEM MODELS

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Effective electric power system planning requires knowledge of factors that are external to the electricity sector; the price of fuel and the substitution behavior of consumers are two examples. Mathematical models that are used in the system planning process typically consider such factors to be exogeneous inputs. This treatment often ignores important simultaneities between the electricity sector and the rest of the energy system. This disadvantage might be overcome if existing energy system models, heretofore used for analyzing policy issues, were applied in the power system planning process.

The research reported here is aimed at assessing the potential usefulness of a number of energy-system models to regional planning of electric utilities. While general features of the models are considered, the focus is on the detail and accuracy of the models' representation of technical, economic, financial, regulatory, and environmental aspects of the electricity sector at the regional level of aggregation. However, since any modeling effort involves trade-offs between scope and detail, another assessment scheme is required. A set of utility-related questions that an "ideal" energy system model might help answer is posed; each model is then tested for its usefulness in addressing the questions.

The following models are considered:

Project Independence Evaluation System
SRI-Gulf model
ICF National Coal model
Baughman-Joskow Regionalized Electricity Model
Battelle Model
Bechtel Regional Energy System for the Planning and Optimization of National Scenarios

I. INTRODUCTION

As a class, energy system models fall between macroeconomic and power system models in scope and detail. They represent both the physical processes of the energy system and the behavioral processes

of a host of decision-makers who influence the state of the energy system. Energy system models contain much more structural and technical detail in the energy sectors than macroeconomic models but as a rule are less detailed than the transmission or capacity expansion models of individual utilities. On the behavioral side, they vary widely in their representation of the interaction among the decisions of producers, consumers, planners, and regulators. For example, some models contain endogeneous approximations to supply curves for energy resources and demand curves for energy products; others treat resource prices and energy demand as exogeneous parameters to be provided by the user. Many energy system models assume cost minimization behavior by producers while others recognize additional influences on their behavior. In spite of this variation, they tend to focus on behavioral relationships in a less aggregated fashion than macroeconomic models and in greater detail than power system models.

These characteristics suggest that energy system models can contribute to the overall planning capability of utilities, as well as regional and national government planners and regulators, because they deal with the complex interaction of decision-makers with different interests and the physical aspects of energy systems. Thus, it is appropriate to assess these models in some detail for their applicability in the area of power systems planning.

In this report six energy system models are described and assessed. Several criteria were used in the selection of models for detailed review. Specifically, a model should possess an identifiable electric utility sector, contain supply and demand components, and be regionally articulated. Although these requirements eliminated a number of well-known energy system models (for example, the Hudson-Jorgenson[24], Brookhaven[20,23], and Stanford PILOT[22] models), it was felt that they were necessary for a regional analysis. The following models satisfied all three of the requirements and were consequently chosen for the assessment:

The Project Independence Evaluation System (PIES) - a detailed energy system equilibrium model developed by the FEA to assist in preparing the Project Independence Report[1-7].

- The SRI-Gulf model, also known as the SRI National Energy Model (NEM) - a detailed energy system equilibrium model originally developed by the Stanford Research Institute to analyze synthetic fuels strategy for Gulf Oil Corporation [8,9].
- The ICF National Coal Model (NCM) - energy system model with detail in coal and electricity sectors developed by ICF, Inc. Updated version called ICF Coal and Electric Utilities Model[10].
- The Baughman-Joskow Regionalized Electricity Model (REM) - energy system model with detail in electricity and nuclear fuel cycle sector[11-14].
- The Battelle Model - energy system model with detail in electricity and nuclear sectors developed by Battelle Pacific Northwest Laboratories (BNWL) to assist in the preparation of their Regional Analysis of the U.S. Electric Power Industry[15-17].
- The Bechtel Regional Energy System for the Planning and Optimization of National Scenarios (RESPONS) - energy system model with detail in coal sector developed by Bechtel Corporation[18].

One of the major considerations in this research was to develop a suitable set of assessment criteria for the six models that were selected. Since most of the models were developed to analyze national energy policies, they do not contain the type of detail in the utility sector that is found in power system models. The function

of the utility sector in these models is to approximate the power industry's generation, capacity expansion and pricing, given factors such as fuel costs, operating costs, capital costs, regulator technology availability, and demand configuration.. For general energy policy questions that do not directly involve electricity this treatment is adequate (if the approximation is reasonable) and the model will fall or stand on the basis of its overall representation of the energy system. For questions that focus on the electricity sector, the criteria become more stringent. However, as we shall see, the type of detail that is required in the electricity sector of a model depends greatly upon the particular question that is addressed. Thus, an assessment based only upon the detail and accuracy of the models is inadequate. Therefore, after discussing the general features and the utility sector representations in the models, we present a set of questions that involve power systems and analyze the capability of the models to answer them. Since the questions were developed to span a wide range of regional concerns, they provide a vehicle for assessing the models in a meaningful manner that will be of use to a cross-section of planners.

II. GENERAL FEATURES OF ENERGY SYSTEM MODELS

As we have mentioned, the usefulness of any energy system model for power system analysis depends to some extent on its representation of the entire energy system. Since space considerations preclude us from describing the general features of these models in any detail, we will give only a brief overview summary here. Table II-1 characterizes each of the models from a

Table II.1: GENERAL CHARACTERISTICS OF ENERGY SYSTEM MODELS

MODEL	SCOPE/FOCUS	TIME FRAME	METHODOLOGY	REGIONS	TRANSPORTATION	SUPPLY TREATMENT	DEMAND TREATMENT
PIES	Entire U.S. energy system	Static-1 period	Iterations between LP and demand model yield equilibrium	9 Demand 12 Coal 7 Refinery 14 Oil and Gas	Endogeneous	Supply curves for major resources by region.	Demand curves for major fuel and electricity by region.
NEM	Entire U.S. energy system	Dynamic-17 periods 1975-2025	Generalized equilibrium modeling	8 Demand 11 Resource 3 Import 6 Refinery	Endogeneous	Supply curves for major resources by region.	Demand curves for major end-uses by region.
NCM	U. S. Coal and Electricity sectors	Static	Linear programming	30 Supply 35 Demand	Endogeneous for coal	Supply curves for coal by region. Other prices are exogeneous.	Demand is exogeneous by region.
REM	U.S. Electricity Sector	Dynamic-101 periods 1947-1997	Deterministic simulation	9 Demand	Price markups for fuels by region	Fuel prices are exogeneous by region.	Demand curves for electricity by region.
BNWL	U.S. nuclear fuel and electricity sectors	Dynamic (time frame is a user option)	Linear programming	9 Demand	Endogeneous	Supply curves for uranium and coal.	Demand is exogeneous by region.
RESPONS	U.S. coal and electricity sectors	Static	Linear programming	User option	Endogeneous for coal	Fuel prices are exogeneous by region.	Demand is exogeneous by region.

number of aspects. A few brief remarks about these aspects, which are listed across the top of Table II-1, are in order.

The scope of a model is the part of the system that is endogeneously represented by the model; the rest of the world influences the model through exogenous inputs set by the user. The focus of a model is that part of the system that is modeled in the most detail. For all practical purposes, the scope of each of these models corresponds to its focus, and thus we list the two characteristics together. The time frame of a model can be thought of as its temporal scope. Half of the models are static; that is, they represent only one period in time. Information from previous years and assumptions about succeeding years must be exogeneously provided. The other three are dynamic because they represent a number of successive periods and internally link the interdependences among the time periods.

In the context of energy system modeling the methodology of the model is the mathematical structure that is used to represent the system and the mathematical solution technique used to predict or suggest the behavior of the system. Linear programming is a popular methodology, and well represented among the set of models of Table II-1.

In order to recognize spatial diversity of electricity demand and energy resources, while at the same time keeping the model a reasonable size, energy system models divide the nation into a discrete number of regions and treat supply and demand homogeneously within each region. The regions column in Table II-1 gives an impression of the degree of regional articulation in each model. Transportation links between supply and demand regions are endogeneously represented in all but one of the models.

It is well known that the price of a resource is not independent of its level of supply; nor is the demand for electricity independent of its price. Whether this fact is implicitly considered by the model is indicated in the supply and demand treatment columns.

III. UTILITY SECTORS OF ENERGY SYSTEM MODELS

Although the models differ greatly in the number and types of generation technologies they include, the manner in which they represent transmission and distribution, and their assumptions about electricity pricing, they have some important similarities. All of the models assume that the utilities in each region act as one regional utility; all capacity of a particular type in a region is aggregated without regard to location. For each generation type, the conversion process is represented by an equation similar to:

$$\text{ENERGY} = \text{FUEL INPUT} \cdot \text{HEAT CONTENT} \cdot \text{HEAT RATE}$$

The heat rate is an average for all the plants in a region and reflects whatever assumptions are made about the mix of plant sizes and efficiencies.

In most of these models, energy and capacity is related through an equation equivalent to:

$$\text{ENERGY} = \text{CAPACITY} \cdot 8760 \cdot \text{CAPACITY FACTOR}$$

where the capacity factor is set to account for planned outage, forced outage, and demand considerations. Several of the models divide the capacity of a particular conversion technology into categories according to whether the capacity will be used to meet peak, intermediate or base load, and assign to each category a different capacity factor. Since all of the models operate existing or build and operate new capacity according to some cost criteria, the above equations provide the technical link for comparing generation technologies on the basis of fuel costs and capital costs. The first equation provides the amount of fuel needed by a particular technology to produce a KWH of electricity; the second equation provides the capacity requirement.

For all of the models annualized capital costs are exogeneously provided for each technology (NEM breaks down capital requirements by factor input and has a representation of energy factor markets). Operating and maintenance costs are also exogeneously specified. Fuel costs may be either endogeneously or exogeneously provided depending on the model and fuel. All but one of the models assume cost minimization behavior in technology choice. This assumption, inherent in LP methodologies, can cause some instability in the solution, i.e., small changes in relative fuel prices or capital costs can cause large changes in the predicted technology split. NEM, on the other hand, also recognizes market shares and non-economic factors in technology choice.

Four of the models recognize the variability in power demand (only RESPON and BNWL treat merely energy demand). REM uses a more or less continuous approximation to the load duration curve. The other models divide demand into several blocks according to power level. Figure III-1

Figure III.1
Load Duration Curve Approximation

illustrates the manner in which these blocks are calculated. Each of these blocks of energy must then be met by capacity assigned to it. The differing capacity factors assigned to different models of generation reflect the duration of the demand in each of the blocks.

Pricing assumptions differ somewhat among the models. Since NCM, RESPON, and BNWL require that electricity demand be exogenously provided, price is not a factor. PIES approximates average cost pricing while NEM assumes marginal (long-run) cost pricing. REM contains a detailed financial-regulatory submodel that calculates electricity price.

Reliability is considered only through the inclusion of reserve margins and capacity factors; none of the models calculates loss of load probabilities. Several of the models permit interregional baseload transmission. The only environmental considerations that are included in any of the models are limitations on the sulfur content of coal that plants without scrubbers can burn. Tables III-1 and III-2 summarize the above discussion and other important electricity sector features of the six models.

IV. THE APPLICABILITY OF ENERGY SYSTEM MODELS TO SELECTED ELECTRICITY RELATED ISSUES

In this section we present a set of six questions of concern to power system planners. For each of these questions we discuss the features that are required of a model for it to provide useful analysis and point out the models that possess the requirements. The set of questions and assessments are then reviewed to determine the areas in which the current capabilities of energy system modeling are deficient and where more research and development are needed.

It should be noted that although this assessment provides a guide for matching models with issues, the final decision to use a model should be made only after the analyst has reviewed the model in detail to determine if it meets his requirements.

Q1. What are the impacts, prospects, and economics of non-transportable energy sources that have different potentials in different regions, e.g., geothermal, solar, or in-situ methods?

Obviously, for any model to address this question the primary requirement is that it must recognize the technology of interest and include certain broad technical and economic parameters such as heat rates, operating costs, energy and power capacities, and capital costs. The models vary widely in the types of technologies they recognize and in the detail they provide. PIES and NEM model a number of specified geothermal and solar technologies; a recent version of REM models wind-powered and geothermal generation. The other models include only conventional fuels.

Exotic technologies and technologies that are still in the development stage pose a particular problem for the modeler since the technical and economic parameters are generally not known for given years in the future. Typically, the year of commercial availability and the parameters are estimated using expert opinion; sensitivity analysis can be performed on technologies that seem particularly promising. NEM includes learning curves that specify the changes in heat rates and capital costs as a function of time (both before and after commercial availability) for each technology. Although this treatment does not solve the problem of uncertainties it does provide an endogenous representation of the influence of technical change.

Regardless of technical feasibility, the success of any technology depends on its economic competitiveness with more conventional fuels. Thus, the model should have a representation of the costs of both conventional and unconventional fuels and a method for measuring the economics of fuel choice. Since we are focusing on regional technologies here, transportation costs for bringing conventional fuels into the region must be provided. All of the models include transportation costs and some mechanism for fuel choice. All of the models that use LP techniques, as well as REM, assume cost minimization behavior in the operating and building of power generation capacity. NEM assumes that behavioral lags and market shares interact with cost minimization to influence technology choice.

For some technologies the shape of the load duration curve is important in assessing the competitiveness and contribution of regional technologies. This is particularly true of solar power, whether locally or centrally generated, because of its non-constant availability. An analysis assessing the impact of residential solar units on the generation patterns and capital expenditures of utilities would most likely start by estimating their effect on utility load duration curves. PIES, ICF, and NEM divide load into several (typically, three) categories; REM contains a more refined representation of the load duration curve.

Hydro-electric power, although a very conventional power source, is of particular regional interest. While all of the models recognize hydro-electric power, in most cases the treatment is limited to specifying hydro-capacities. Since hydro-electric plants are highly site-limited and none of the models consider siting within regions, it is doubtful that any of them would be useful in a detailed hydro-electric analysis.

NEM and PIES are the most likely candidates for analyses involving regional technologies because of the breadth of technologies they model. NEM has some especially attractive features for analyzing unconventional technologies: 1) it is dynamic and thus the introduction rates of these technologies can be measured, 2) it has internally stored learning curves for important parameters,

Table III.1: UTILITY SECTOR CHARACTERISTICS OF ENERGY SYSTEM MODELS (Generation Representation)

MODEL	TECHNOLOGIES REPRESENTED	CONVERSION POSSIBILITIES	ENVIRONMENTAL CONSTRAINTS	CAPACITY FACTOR TREATMENT
PIES	Low sulfur coal, high sulfur coal (w or w/o scrubbers), fuel gas, ng.st., ng.tur., res.oil, dis.oc, dis.cc., hydro, nuclear, geothermal, solar	Scrubbers added to coal, oil to ng., ng. to oil, dis. to ng., ng. to coal, oil to coal.	SO ₂ limits on coal	Prespecified for base intermediate and peaking plants.
NEM	Coal st., coal cc., methanol, gassified coal, ng.st., ng.cc., res.st., res.tur., dis.oc., dis.cc., hydro, solar, geothermal, biomass HTGR, GCFBR, LWR, LMFBR	NONE	NONE	"
NCM	Coal, nuclear, oil, ng., hydro	Scrubbers added to coal plants.	SO ₂ limits on coal	"
REM	Coal st., fluidized bed coal, ng.oc., ng.cc., oil st., LWR, LMFBR, Molten carbonate fuel cell, naptha fuel cell, advanced battery, geothermal, hydro, pumped storage, IC and gas peaking.	NONE	Capital cost markups on coal by region	Forced and planned outage represented separately
BNWL	Coal, oil, 18 nuclear types	NONE	NONE	Capacity factors are a function of plant age.
RESPONS	Conventional coal (w or w/o scrubbers) advanced coal, oil, ng., nuclear, hydro.	NONE	SO ₂ limits on coal	Prespecified for base and peaking plants.

Abbreviations: tur.- turbine cc.- combined cycle dis.- distillate oil
st.- steam oc.- open cycle res.- residual oil ng.- natural gas

Table III.2: UTILITY SECTOR CHARACTERISTICS OF ENERGY SYSTEM MODELS (System and Economic Representation)

MODEL	LOAD CURVE REPRESENTATION	PRICING AND REGULATION	RELIABILITY	FUEL COSTS	CAPITAL COSTS	INTER-REGIONAL T & D	INTRA-REGIONAL T & D
PIES	3 load categories	Average cost pricing	Not considered	Endogeneous	Exogeneous	NONE	9% T&D loss. T&D operating cost, proportional to generation. New T&D cost proportional to new capital.
NEM	3 load categories	Long-run marginal cost pricing	Not considered	Endogeneous	Endogeneous	Base load only	Not modeled
NCM	4 load categories	Not applicable, demands are exogeneous	Not considered.	Endogeneous for coal only	Exogeneous	Base load only	about 9% T&D loss according to region
REM	Continuous approximation	Detailed financial/regulatory submodel	20% reserve margin (installed capacity/peak demand = 1.2)	Exogeneous	Exogeneous	NONE	Econometrically estimated equations based on land area, no. & nature of customers, load density, and total KWH sales provide estimates of regional T&D requirements.
BNWL	NONE (over-all energy)	Not applicable, demands are exogeneous	Not considered	Endogeneous for coal and nuclear only	Exogeneous	Yes	Not clear from documentation
RESPONS	NONE (over-all energy)	Not applicable, demands are exogeneous	Not considered	Endogeneous for coal only	Exogeneous	Yes	Not modeled

and 3) its market share and behavioral lag assumptions are appropriate for new technologies. RESPON, BNWL, and ICF focus on coal or nuclear and thus are not particularly suited for this type of question. REM has the advantages of having multiple time periods and detailed load duration curves but does not currently contain any solar representation.

Q2. What will be the usage pattern among regions of conventional and transportable fuels?

This rather general question can be broken down into a whole class of more specific questions such as: Given transportation costs and regionalized supply and demand curves, what will fuel costs be? How sensitive will utilities' plans and the price of electricity be to fuel costs? What will be the overall demand on regional transportation links and what new transportation or transmission capability is required? What will be the effect on electricity supply interruptions due to bottlenecks or allocation?

These types of questions demand broad scope in a model. Supply curves by production or import region should be included for all major fuels and transportation links (with costs and capacities) between supply and demand regions should be endogeneously modeled. These features are necessary because fuel choice is a function of both supply prices and transportation costs. Demand curves for energy products are needed also in order to recognize the price-sensitive substitution behavior of consumers between electricity and other fuels. Finally, base-load electrical transmission capability between regions should be modeled, particularly for long-term studies, because it is a viable alternative to transporting feedstocks.

None of the models discussed here exactly meets all of these requirements; however, two of them, PIES and NEM, would meet them all with only very minor adjustments. Both models have regionalized supply curves (and/or detailed modeling of production activity), detailed transportation links, and demand curves for energy products. Although they use somewhat different methodologies, both derive equilibrium solutions of quantities and prices for the entire energy economy. NEM provides for inter-regional base-load electricity transmission; PIES does not but it could be added within the LP framework of the model. Neither model places capacities on transportation links. Again minor modifications would yield versions of the models that recognize capacities.

NEM, with its network structure of individual processes, has the advantage that it is somewhat more flexible than PIES. The dynamic nature of its representation of the energy system through time is also appealing. On the other hand, the PIES data base has, by all indications, been developed, critiqued, and distributed more intensively than its counterpart in NEM. Because of the experience that DOE has with PIES, it would be the choice for its in-house studies in the area. This experience and the PIES computer programs do not appear to be readily transferable to other

installations and thus NEM is recommended for other analysts.

Q3. What is the relationship between capital availability and future economy and reliability?

To finance new facilities, utilities must compete in capital markets. The rate of return allowed utilities influences their competitiveness and the price for electricity to consumers. If this rate is too low, dependence on fuel intensive generation technologies or under-expansion may result and consumers may pay in interruptions or higher fuel costs. On the other hand, a high rate of return would lead to higher than necessary costs of service.

All of the models evaluated here include capital costs for new capacity. Within an LP framework, limits on total capital expenditures by utilities can be modeled. The LP solution techniques would indicate a building program that balances fuel costs and capital costs within the budget constraint. Thus, any of the four models that employ LP techniques could conceivably be used in this type of analysis. However, an external analysis would be necessary to relate capital availability to rate of return. Further, such a treatment would probably require changing the LP structure rather than merely the input data. Unfortunately PIES, NCM, and RESPON are static models and capacity expansion is assumed to occur somewhere between the present and the target year. Given the complicating effects of different lead-times and unstable fuel costs, this aggregation in time precludes all but cursory analysis of this question. BNWL is dynamically specified and with its detailed modeling of nuclear plants may be useful in testing the effects of capital availability on expansion of the nuclear industry.

NEM treats capital costs somewhat differently than the others. Each unit of capacity that is built for a plant type is assumed to require secondary factor inputs in fixed proportions. Process submodels keep track of overall demand for these secondary inputs and provide prices for the inputs (based on demand level) to the utility sector. Presumably, limits could be placed on capital expenditures by utilities within the utility submodels. How this would effect the solution technique that NEM employs is unclear.

REM has a fairly detailed financial-regulatory submodel that simulates rate setting as a function of regulated rates of return and financing based upon cash flows internal to the industry and rules of prudent financial management. REM seems to treat capital demand in a manner superior to the other models; what it does not contain is a supply of capital relationship. Thus the model does not equilibrate the market for capital for the electric utility sector. The model is designed simply to report capital shortages given a regulated rate of return, not simulate a compensating behavior of the industry to such a shortage. Therefore, additions to the model will be needed before it can rigorously deal

with this question. On the other hand, ad hoc procedures (such as placing capacity limits on expensive new plants) are just as applicable to EM as to the other models.

- Q4. What will be the effect on utility generation and expansion plans of various pricing schemes, e.g., marginal cost pricing, peak load pricing, or changes in the industrial-residential differential?

Whether the demand side of the system is endogeneously or exogeneously specified, this type of analysis will begin with estimating the effects of pricing schemes on the regional system load duration curves. Thus internal representation of approximate load duration curves is a necessity - this requirement immediately rules out BNWL and RESPONS since they recognize only total yearly energy demand. The remaining models probably have enough detail in their representation of system load to approximate the effect of different load patterns on the capacity and generation configuration of the utilities. The feedback of capacity and generation costs, and the resulting price schedules, to the load duration curve is more problematic. The demand sectors of PIES, NEM, and REM already contain internal pricing assumptions, and it is not clear what range of analysis could be performed without altering the structure of the models; NCM, of course, does not model electricity demand endogeneously. Further research, on a model specific basis, is needed to determine exactly how these models can be used in rate studies. At this point, it can be said that PIES, NEM, REM, and NCM hold promise.

- Q5. What are the long-term effects of the price of electricity on regional industry and commerce?

In the long-term, electricity price differentials among regions may result in industrial and population shifts with the ensuing effect on regional economies (and demand for electricity). Long-run elasticities embedded in the econometrically-estimated industrial demand equations in PIES, NEM, or REM might reflect the effect of price on electricity demand well enough for utility demand projections. However, they are not sufficient for measuring the effect of price on the regional economies because it is not clear if long-term elasticities in demand are due to migration or factor substitution behavior by regional industry or population. Clearly, some structural representation of the production functions of regional industries is required to accurately measure the effect of electricity price on the competition among regions for various industries. None of the models discussed here recognize any of the relationships between the electricity sector and regional industry, and are therefore unlikely to help in addressing this question.

- Q6. What will be the effects of various plant emission, stripmine reclamation, and mine safety standards on the usage of coal by utilities?

A rigorous analysis of this question requires the recognition of the interplay between coal production costs by region (which will reflect mine safety and reclamation standards), sulfur and BTU content, transportation costs, and emissions standards and heat rates at coal-fired generation plants. The two models focusing on coal, NCM and RESPONS, model this interplay well. They contain supply functions for different types of coal (sulfur and BTU content) by supply region. The models keep the coal types separate during the transportation from supply regions to demand regions. Consequently, coal arriving at generation facilities is identified by sulfur and BTU content, where emission standards are applied to high-sulfur coal in the form of scrubber requirements. The BTU content of coal arriving at the generation facilities provides a disaggregated measure of fuel cost per KWH for a given plant.

Although several of the other models include emissions controls, none of them model the interplay among production, transportation, and usage as accurately as NCM or RESPONS. PIES, for example, keeps some accounting of sulfur content and imposes some constraints on emissions in the form of scrubbers. However, the larger scope of these other models in no way makes up for the greater detail in NCM and RESPONS. Thus, for this particular question they cannot be recommended.

V. SUMMARY

Clearly this brief list of questions does not exhaust those of concern to electric utility planners and energy regulators. A study of this sort cannot be definitive for this reason. On the other hand the list is selectively oriented to issues of electric power planning and regulation and covers a broad range of policy and planning problems. Our purpose from the outset has been to assess the models for their applicability to power systems planning, recognizing that both public and private entities are engaged in the activity. Based upon our review of the models and their potential for analysis of aspects of the questions raised, we summarize with the following observations.

1. To the extent that power systems planning is defined as what type of plant, of what size, should be built when and where, none of the models reviewed herein are of use. The models sacrifice essential detail necessary to address this specific planning problem. The models generally assume constant returns to scale, treat issues of reliability in only a cursory fashion if at all, lack the detailed geographic characteristics for the region, the intra or inter-regional generation and transmission possibilities, and have no detailed plant-by-plant production simulation capability.
2. To the extent that power systems planning can be described as the more classical economic notion of discovering and removing inefficiencies in supply and pricing of electrical

service, none of the above models apply. The energy system models generally assume cost minimizing behavior by the producers of electricity, assume away the economies of scale in production, neglect completely the problems of joint costs, and make no attempt to quantify externalities.

3. To the extent that power systems planning can be defined as planning joint production and transmission facilities in and among regions, none of the models apply. The models are too gross in geographical detail, they do not capture the properties of dynamism and diversity of load, and again treat reliability in much too cursory a fashion.
4. To the extent that regional power systems planning can be defined as estimating a priori a region's electricity sector response to changes in costs of factor inputs, such as fuel or capital, or changes in emission standards, then several of the models potentially apply. However, none of the models discussed is superior to all others for application to all questions of regional interest. Each model's strengths and weaknesses are summarized in Table V.1.

Table V-1: CHECK LIST FOR APPLICABILITY OF MODELS TO SELECTED QUESTIONS¹

Model	Non-Trans-portable Source	Trans-portable Sources	Capital	Pricing	Regional Industry	Environmental
PIES	YES	YES			NO	NO
NEM	YES	YES			NO	NO
NCM	NO	NO			NO	YES
REM		NO	YES		NO	NO
BNWL	NO	NO		NO	NO	NO
RESPONS	NO	NO		NO	NO	YES

¹Unfilled boxes indicate potential applicability to certain aspects of the question - see text for details-

The models examined were all developed for the purpose of energy policy planning and analysis. They have been applied to analysis of a variety of public policies affecting the supply and demand of energy. All contain a regionalized articulation of the electric utility sector. In spite of this, the models have found little regional application. This is partly the case for lack of identifiable users. More importantly, we suspect that the aggregation and treatment of behavior of the utility sector within a regional aggregate of these national models is far too gross to be persuasive in any regional forum.

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state-of-the-art of regional power systems planning. The general contractor for this project was the University of Oklahoma. The authors accept full responsibility for the contents of this paper.

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- [7] Soyster, Allen, Virginia Polytechnic Institute, Representation of Load Duration Curves in PIES, paper presented at ORSA/TIMS Meeting, November 1977, Atlanta Georgia.

[2] and [3] summarize the findings of the Federal Energy Administration in their Project Independence study. PIES is described in a very sketchy fashion in the appendices of [2] and [3]; the electricity sector is hardly mentioned at all. [5] is the first volume of a 15 volume documentation of the model. Chapter Nine covers the electricity sector in some detail if with little clarity. [7] is a clear exposition of the way load duration curves are handled within the LP methodology of PIES. [1], [4], and [6] are independent reviews of the Project Independence Report and to some extent PIES. Except for some brief comments about the accuracy of input parameters, [1] does not discuss the electricity sector of PIES. Its reservations with the PIES model in general focus on its lack of resource constraints, insufficient disaggregation, and its static nature. [4] and [6] discuss the electricity sector of PIES

and report overall satisfaction with several reservations. The authors of both reports object to the prespecified capacity factors and the lack of financial constraints in the model. They feel that these factors cause PIES to overstate future coal, and particularly nuclear, capacity.

The SRI National Energy Model

- [8] Cazalet, et al., Generalized Equilibrium Modeling: The Methodology of the SRI-GULF Energy Model, Draft report prepared for Federal Energy Administration, March, 1977.
- [9] Stanford Research Institute, A Comparative Analysis of Methodologies Used in Large Scale Energy Modeling, Draft report to National Science Foundation, Contract NSFC-915.

[8] is an 81 page draft documentation of the methodology of the SRI-Gulf model (now called the SRI National Energy model). It describes the form of the equations that are used to represent energy processes, the solution techniques for solving the equations and related computational requirements. It does not contain a specification of the complete network nor does it provide the values or derivation of the parameters that are used in the various equations. Pages 43-46 focus on the electricity sector.

[9] is a comparative discussion of the methodologies of a number of energy system models. A good overview description of the NEM appears in Section III.

The ICF National Coal Model

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This is the documentation for the current version of what was originally the ICF National Coal model. The description is well-written and quite complete; it provides a good overview as well as the derivation of the data and documentation of the computer program.

The Baughman-Joskow Regional Electricity Model

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[11] is a book length conceptual description of REM; [13] is the documentation for the computer program. [12] addresses the effects of aggregation in the model and anticipates future improvements. A fairly detailed critique of REM is contained in [14].

The Battelle Northwest Laboratory's Electricity Model

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These four volumes document the electricity sector of the model; the other volumes cover non-electricity sectors such as coal supply.

The Bechtel RESPONS

- [18] Nagavala, R. J., Ferrell, G. C., and Olver, L. A., Regional Energy System for the Planning and Optimization of National Scenarios (RESPONS), Report to U.S. Energy Research and Development Administration, Bechtel Corporation, San Francisco, June 1976.

Volume 1 of [18] describes the model, required data, and computational considerations. Pages 113-127 cover electric power generation. Volume 2 describes the scenarios and provides a user's manual for the computer program. See also: [19] under "Other Models" heading.

Other Models

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[19] describes another model developed by Bechtel Corporation that models the U.S. energy supply system but did not meet all of the requirements for this assessment. [20] and [23] discuss the Brookhaven energy models. [22] and [24] discuss the Stanford PILOT and Hudson-Jorgenson models respectively. [21] is an overview assessment of a number of energy system models and provides a good general introduction to energy system modeling.

SECTION 6.4

REVIEW OF ENERGY SYSTEMS MODELS APPLICATIONS TO REGIONAL ELECTRIC UTILITY PLANNING

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ABSTRACT

A review is made of various energy systems modeling techniques, and their applicability to regional electric utility planning is discussed. Eight energy systems models representing a wide range of techniques, sophistication, and comprehensiveness are described.

Baughman-Joskow Regional Energy Model
Brookhaven National Laboratory Energy Model
Dartmouth COAL Model
Jones Electric Utility Model
Oregon State Simulation Model
Project Independence Evaluation System
Stanford Research Institute Energy Model
Wisconsin Energy Model

Also, areas where research is needed to improve the usefulness of energy systems models for regional electric utility planning are discussed.

INTRODUCTION

During the period beginning after World War II and extending until the early 1970's, the United States energy system, in general, and the electricity component, in particular, experienced relatively smooth trends. Middle- and long-range planning needed only to deal with what appeared to be a reasonably certain future. Considerably different conditions are evident this decade as the energy system moves from a period of inexpensive, abundant energy and stable economic growth to a period of expensive, scarce energy and economic uncertainty. As a result, the electric utility industry's operating environment has changed from favorable conditions with decreasing costs and smooth load growth to relatively adverse conditions with increasing costs and uncertain load changes. It is the function of electric utility planners and other planning agencies to maintain a reliable and economic electricity supply under these conditions.

This report describes the results of a review conducted to assess the applicability of energy systems modeling as a tool to aid in regional electric utility planning. This review

is one part of a larger study to assess the current state-of-the-art, applications, and limitations of various types of models in regional electric utility planning.

The study is limited to regional planning and consequently deals mainly with planning by utility groups of state and federal government agencies. The purpose of planning at this level is essentially the same as for an individual utility; however, some new considerations are added, such as joint cost and risk sharing between utilities or regulatory policies by government agencies. Also, the reliability and economics of a considerable larger system are now under consideration. Regional planning must also consider the reluctance of individual utilities to consent to plans which will benefit the regional system, but will be detrimental to the individual utility.

For the purpose of this review, energy systems models are defined as those models which address the energy system as a group of interacting components rather than considering each aspect of the energy system in isolation. A model need not to consider all aspects of the energy supply/demand system to be considered a systems model but it must consider the relationship of each part to the system as a whole. No particular modeling technique is implied by the systems model designation. The models reviewed incorporate most of the standard modeling techniques.

The objectives of this review are 1) to determine the usefulness of existing models and established modeling techniques for regional electric utility planning and 2) to determine research needed to improve the value of such models for regional electric utility planning.

APPLICATIONS OF SYSTEMS MODELS TO PLANNING

The utility planning function can be divided into two interrelated parts; 1) projecting the environment for future operation (economic, social, political, etc.) and 2) designing a power system which provides an economical and reliable supply of electricity. Historically, most efforts at utility planning have been directed at the second part of the planning function. Detailed generation expansion and transmission models have been developed to aid in

devising and assessing the economics and reliability of various expansion plans. This emphasis is understandable in view of the relatively stable trends which have occurred in the past. However, the second planning function is dependent upon accurate projections from the first function. The less stable trends seen in the energy system in recent years make the projection function more difficult and increasingly more important. In the opinion of the author, there are four areas where accurate projections are essential for effective utility planning:

1. Demands for electricity.
2. Price and availability of generation of fuels.
3. Capital cost and technological developments.
4. Environmental, social and political constraints.

It is in the role of projecting these factors that energy systems models have the most potential for use in regional electric utility planning. Some of these factors cannot be projected but rather are included in the function of some planning agencies. These are generally policy questions; and energy systems models may be useful in assessing many of these policies.

In view of this discussion, several areas where energy systems models may be useful have been identified.

Load Forecasting

Accurate load forecasting is probably the most essential element of sound electric utility planning. The degree of uncertainty which planners perceive in their load forecasts has increased markedly in the past ten years. Whereas planners may have questioned whether loads would grow at annual rates of five percent or six percent in the past, today they question whether load growth rates will return to previous trends, will level off to zero, or will be negative. This high degree of uncertainty is especially difficult to handle. Planning based on load projections which are too low will have serious consequences in terms of system reliability while planning based on load projections which are too high will adversely affect economic operation.

Energy systems models certainly cannot remove all of this uncertainty, but they may be of some assistance. The demand for electricity depends not only on growth of current uses but may be altered significantly by substitutions between electricity and other fuels. Both of these are sensitive to electricity prices and the prices of competing fuels. The broader perspective provided by systems models should assist in projecting future conditions by considering these interrelationships.

There are several additional potential applications related to load forecasting. These applications deal with inter-regional shifts in demand for electricity, shifts in load characteristics, and fluctuations in electricity demand. The inter-regional shifts in electricity demand may result from new patterns in economic development or changing costs of electricity and competing energy forms. Systems models with inter-regional disaggregation may be able to show how these shifts will occur. Changes in the end uses of electricity may substantially alter the characteristics of the loads which utilities serve. Models formulated to describe end use may show what changes are likely. They may also be able to show the resulting changes in load characteristics if they contain sufficient detail in the electric utility component. Finally, the changes occurring in the energy system are ending the stable trends seen in the past. Electric utilities are likely to experience erratic load growth in the future. Systems models may be able to show the nature of fluctuations that may occur and how electric utilities will respond under these conditions.

Policy Analysis

Energy policy analysis is one of the applications most cited by developers of energy systems models. Almost any model can perform some kind of policy analysis. One may suspect that policy analysis applications are sometimes used to make what would otherwise be only an academic exercise appear useful. However, a means to assess the impacts of specific policies is an essential part of proper planning as the role of government and regulatory agencies increases in importance. Policy analysis is, to some extent, a new dimension to utility planning. Rather than simply responding to eventualities as they occur, policy analysis attempts to determine what can be done to make certain events occur. Such policies may include assessment of regulations, incentives, reducing regulatory red tape, and specific technology development programs.

Generation Fuels

The prices and availabilities of fuels used for generation are important considerations in generation planning. Most of the comments made previously about electric loads also are true for fuel prices and availabilities. The smooth, stable trends of the past no longer exist. Utility planners must make difficult choices between alternative fuels; and the wrong choice can be very costly, both in terms of economics and reliability. Energy systems models which incorporate a wide range of energy types are useful in predicting long-range trends in this area. They still cannot remove all of the uncertainty, but they may give a clearer picture of what can happen.

Technology Assessment

Technology assessment could conceivably include a very wide range of possibilities. There are, however, three basic types of technology which directly impact electric utility planning. The first type deals with technology involved in energy supply where the fuels used in generation are produced (e.g., low Btu coal gasification). The second type deals with the technology involved in the end use of electricity (e.g., electric heat pumps). The third type deals with the technology involved in generating and transporting electrical energy (e.g., MHD power generation). Energy systems model applications in these areas are of particular value in assessing research and development programs and programs to implement new technology. They also may be important, from an electric utility view point, in determining the long-term costs or benefits of utilizing new or different technologies within a region. The primary method of evaluating these technologies is to assess system performance with and without a particular technology or group of technologies. This approach normally must be conducted in the context of a system larger than just electric utilities.

Summary of Applications

Although the potential applications for energy systems models represent only a part of the total electric utility planning requirements, these models may assist with an important part of this process. Generally, the energy systems models can provide the inputs used in the detailed analysis of generation and transmission required in planning. These detailed analyses are no better than the input information on which they are based. Thus, if energy systems models can improve the quality of these inputs, their contribution is significant.

No single energy systems model will be appropriate for all of the applications discussed. The following sections classify systems models in various ways and discuss the suitability of different types of models.

TYPES OF MODELS

There are a number of ways to classify energy models. In this section, they will be classified by their spatial and functional aggregation or disaggregation. In the next section, the various mathematical techniques are discussed.

Inter- Versus Intra-Regional Models

There are two basic types of regional models. The first type is the model developed for a single region. This includes models developed for a specific region or general models which may be applied to a specific region. Models of this type may be termed intra-regional because they

consider only the energy system within a specific region, with variables representing other regions treated as inputs. Inter-regional models, on the other hand, contain a number of sub-regions within the overall model region.

Built-Up Versus Broken-Down Models

Inter-regional models can be further classified by the method in which they are developed. The multiple-region quality can be developed in two ways. The first is to build the model up on a region-by-region basis, i.e., the overall model consists of a set of building blocks, each representing a single region. The second method is to use an overall model and break it down into sub-regions. In this latter approach, an allocation or disaggregation of the overall region activity is broken down into activity within the individual regions; whereas, in the first approach, the overall results are determined by summing the results of the sub-regions. This first approach may be termed "built-up," and the second may be termed "broken-down."

Comprehensive Versus Specific Models

A final classification which can apply to either inter- or intra-regional models is the degree of completeness with which the energy system is included in the model. A model may consider only a single part of the system, such as electric utilities, or all processes from resource extraction to end use for all energy forms and also may include the relationship of the energy system to the overall economic system. Models of the latter nature are termed "comprehensive," while the models of the former nature are termed "specific." Most actual models normally fall somewhere between these two extremes; however, the general nature of a model is usually evident. It either focuses upon a single part of the system or attempts to give an overall view.

Areas of Applications

As would be expected, different types of models fill different niches. These niches are fairly self explanatory. The intra-regional regional models are obviously limited to analysis within a single region. However, they may be more suited for describing unique features of that region, such as load characteristics, than the inter-regional models. The larger inter-regional models are more suited for dealing with variables that may be influenced by factors in a larger area, such as shifts in regional load patterns or depletion of some energy resources.

Similary, comprehensive models are suited for areas such as demand forecasting or projecting boiler fuel prices where the interaction of various components of the energy system are important. The specific models, on the other hand, may be more useful for addressing particular questions.

For example, a model dealing only with electricity supply may be appropriate for studying a specific policy such as boiler fuel regulations.

The particular niches for built-up versus broken-down models are less distinct than for the other classifications. Here, the difference is mainly one of the modeler's preference of how to represent inter-regional systems. Generally, the built-up approach allows more detail to be included but requires more data and time to develop a model.

MODELING TECHNIQUES

A number of modeling techniques have been used in developing energy systems models. The following discussion briefly describes some of the traditional modeling techniques which are employed in model building. These techniques are the basis for the models reviewed, however, some models employ combinations or variations of these techniques.

Linear Programming

Linear programming is a technique traditionally used to find the optimum solution to the classical transportation problem--using inputs from various sources to produce a given output. The applications in energy systems are analogous. A linear program can be used to find the optimum mix of resources combined with various processes and transportation links to supply required energy. The linear program also can be used to calculate the energy prices and flows at each point in the system defined by the various processes and transportation links. The optimum calculated also can be made subject to a number of constraints such as environmental regulations or resource limits.

Linear programming is a powerful mathematical tool. It allows a large amount of information to be incorporated into a formalized framework. This ability to incorporate large amounts of data is also probably the largest drawback to linear programming. Costs and efficiencies of each link in the system must be provided. Other parameters, such as emissions, also must be provided if they are to be included in the optimization. Compiling this large amount of information is tedious and time consuming. Another limitation of linear programming is the necessity of formulating the model strictly in linear relationships. Nonlinear relationships can be handled but require a step-wise solution where each step represents a linear formulation.

Network Analysis

Network analysis is similar in many respects to linear programming. A similar network of processes and transportation links is used to simulate the energy system, however, network

analysis does not require linear relationships and normally uses unconstrained relationships. The specific mathematical formulation used for each relationship is largely left to the user's discretion. Network analysis is considerably different in function from linear programming. Rather than determining a system optimum, network analysis describes how each link in the network will act under given conditions.

The network analysis formulation allows the incorporation of much of the same information as linear programming and thus, some of the same advantages and disadvantages. Network analysis can be combined with similar supply and demand information to determine system configuration. These calculations normally require an iterative solution. As a result of the non-linear formulation, sophisticated algorithms are usually required to guarantee convergence to a solution.

Systems Dynamics

Systems dynamics* is a modeling technique which is based after the static variable representation used extensively in electrical and mechanical systems analysis. Systems dynamics originally was designed to study dynamics in industrial systems, but has since been adapted for use in studying a wide range of economic and social questions. There is no rigid form to a systems dynamics model; the particular form used in a model is developed largely by the model builder. Systems dynamics models emphasize change in the system modeled. The important model relationships center around the forces which cause this change.

The flexibility in the format of a systems dynamics model is both the technique's greatest asset and its greatest liability. The format allows the models to be developed for each application with no constraints as to how the system structure should be defined. It also places the burden of defining this structure upon the model builder, resulting in a wide range in both the sophistication and quality of systems dynamics models.

Econometrics

The term "econometrics" is used in this report to refer to those techniques employing historical data in concert with statistical analysis to develop modeling relationships. There are two basic types of energy relationships for which econometrics are used. The first deals with the response of energy demand or resource supply to changes in prices. These are termed "price elasticity relationships" and are divided into own-price and cross-price categories to reflect the effect of a product's own price or the price of other products. The second type

*Systems dynamics also is referred to as dynamic systems simulation and Forrester modeling.

of relationship deals with relating energy demand to more general economic variables such as population, income, GNP, etc.

A fairly formalized structure normally is employed in using price elasticities. A straightforward application of statistical analysis to historical data aids in eliminating the bias of model builders. The structure is not as rigid for the relationships involving general economic variables; however, standard statistical techniques still may be employed. This reliance on historical data provides for some degree of model validity, but it also limits this validity to the range of conditions represented by the data.

Input/Output Analysis

Input/Output (I/O) analysis is a method which relates the inputs required from various economic sectors to manufacture or otherwise produce the output of each sector. A large matrix of coefficients relating these inputs and outputs is the core of any I/O analysis. Through matrix manipulation, other information can be derived. I/O analysis is commonly used to calculate the net increase in output of all sectors which results from an increase in any other sector. I/O analysis, in principle, can be applied to a region of any size. Its emphasis on the interactions between sectors makes it more suitable for larger regions. Also, the linear nature of I/O analysis limits the time period for which it is accurate.

Economic and Engineering Analysis

Economic and engineering analysis refers to those calculations imbedded in a model which reflect, in a simplified form, the same calculations that an industry or company being simulated might use. There is no particular form to this technique. It might best be described by contrasting it to econometrics. Econometrics is a macro-technique; the emphasis is placed on describing aggregate changes by a number of individuals or businesses. Economic and engineering analysis, on the other hand, is a micro-technique, emphasizing the description of how a single business or industry acts and the reasoning behind its actions. Economic and engineering analysis normally deals with cost trade-offs or technical considerations. When properly used in a model, this technique gives an accurate representation of how individual components of the system operate under a range of conditions. Its use also requires an in-depth knowledge of how the industries or businesses modeled operate.

Areas of Application

Each of the modeling techniques described has certain areas where it is particularly suited. Linear programming and network analysis are both well suited for handling large, complex systems in a structured manner. The optimization ability of linear programming is useful in showing how the energy system should or could operate. Net-

work analysis is useful in incorporating a large number of system processes into a simulation of the energy system. Systems dynamics is more suited for showing long-term trends in the system involving major changes. Systems dynamics may also be useful in showing transients which occur as changes take place. Econometrics techniques are useful in describing aggregate energy demands. Econometric relationships are usually the link tying energy models to driving economic parameters. I/O techniques traditionally have been used more in conjunction with overall economic models rather than in energy systems analysis. They may serve this same role in energy systems models which are tied to a model of the economy. Economic and engineering analysis provides the detailed assessment needed for thorough descriptions in specific studies.

COMPARISON OF MODELS

Selection

Several criteria for selection of models to be reviewed were set forth at the beginning of this project.

1. The model must have an identifiable electric utility component.
2. The model must have regional applications. Regions as large as the eastern United States or as small as two neighboring utilities were considered. National models were not rejected if they had identifiable regional applications.
3. The model must have identifiable uses in regional planning. These applications can be from the point of view of utilities or governmental regulatory agencies.
4. The model must be a systems model in that the electric utility component is not considered separately but as a part of a larger supply/demand system.

A large number of models conceivably could meet these criteria. The models selected for review were chosen to represent a variety of techniques. The set of models selected should not be considered a comprehensive list of models which may be applicable to regional planning. These models are meant to give a representative cross-section of what is available.

Eight models were selected for the review:

Baughman-Joskow Regional Energy Model (REM)
Brookhaven National Laboratory (BNL) Energy Model
Dartmouth Systems Dynamics Group Models (COAL1)
Jones Electric Utility Model

Oregon State Simulation Model (OSSIM)
Project Independence Evaluation System
(PIES)
Stanford Research Institute (SRI) Energy
Model
Wisconsin Energy (WISE) Model

An overview of the scope of these models is given in Table I.

Function

Table II briefly describes the function of each model in terms of how it treats energy demand, energy supply, and the economy. Figure 1 presents an overview of what is included in each model. As can be seen, the models vary widely in their comprehensiveness and their level of detail, yet each of the models is similar to the others in several respects.

Probably the most comprehensive of the models is the Project Independence Evaluation System (PIES). This is not surprising since it is the key evaluation tool for Project Independence. A tremendous amount of time and effort has gone into the development of this model. PIES considers supplies and demands on a regional level on a fairly detailed basis. The intermediate processing and transportation steps also are included. All of this is integrated to give an overall supply-demand balance for the United States.

The BNL energy model and the SRI energy model also are fairly comprehensive in that they include energy supplies and demands for all major energy forms. However, both concentrate on the conversion and transportation processes which allocate the energy resources to end uses. Actual supplies and demands are input information. The SRI model is inter-regional with different regional divisions for specific supplies and demands. The BNL model considers a single region ranging up in size to include the entire United States. There also is a recently developed regionalized version of the BNL model which is not reviewed here.

The COAL1 model also is a comprehensive energy model in that it considers both supply and demand for major forms of energy. However, the COAL1 model is more aggregated than the above models and does not address the complexities of the conversion and transportation processes. Its perspective is from an overview of the United States energy supply/demand system, and it shows the overall effect of depletion and changing costs.

REM, OSSIM, and WISE models are more specific than the above models, but in different ways. The WISE model is a comprehensive energy model and also includes economic simulation; however, it only includes a single region--the state of Wisconsin. REM, on the other hand, considers the entire United States (on a regional basis)

but centers on the electric utility industry. It considers demands for all major energy forms but only addresses the supply of electricity. OSSIM is a comprehensive socio-economic model but considers only the electricity demand component of the energy system.

Modeling Techniques

An overview of how the various modeling techniques are employed by each of the models is given in Table III.

Again, no two models use exactly the same set of techniques. As would be expected, the more complex models use the more structured techniques. The BNL model and PIES both use linear programming to handle the complex network of energy conversion and transportation processes. The SRI model uses network analysis for a similar network. PIES also uses an econometric model to determine energy demands and a complex integrating technique to balance supplies and demands.

The less comprehensive but more specific models tend to use the less-structured modeling techniques. REM, the Jones model, OSSIM, and the WISE model all incorporate systems dynamics and economic and engineering analysis. These techniques allow more flexibility in tailoring the model to the specific entities being modeled. REM and OSSIM also incorporate econometrics in a more general treatment of energy demand.

Finally, the COAL1 model combines systems dynamics and econometrics. In this case, systems dynamics is used to allow the flexibility needed to simulate the major changes that occur in the energy system as resources are depleted and costs rise. Econometric techniques, somewhat modified from conventional usage, are used to relate overall energy use to GNP, to determine investment in energy facilities, and to show shifts in energy demand.

Applications

Figure 2 summarizes the potential regional electric utility planning uses of the models reviewed. The indicated uses reflect applications in which the models have been utilized, potential applications claimed by the model builders, and the author's own assessment of potential applications.

Electric utility policy analysis is seen to be an application common to all of the models. Other applications are more dependent upon the particular design of a model. The BNL model, COAL1, PIES, and the SRI model are all multi-fuel models and can show some of the impacts that may result from non-electric utility policies. The demand forecasting incorporated into REM, OSSIM, PIES, and the WISE model may make them useful for load forecasting. The

inter-regional formulation of REM, PIES, and the SRI energy model should give them the capability of showing major inter-regional load shifts. However, this capability is limited largely to the accuracy of the input variables on which the demands are based. The BNL model and the WISE model both can address the characteristics of end uses and can reflect resulting changes in electric utility load characteristics. COAL1, PIES, and the SRI model all conduct overall energy supply/demand balances and indicate energy prices and availability of fuels that may, among other things, be used for electricity generation. The BNL model is designed largely for energy technology analysis and can be used to assess the impact of a variety of technologies on the overall energy conversion and transportation system. The WISE model also has been used to assess the impact of changed end use technology (e.g. high efficiency air-conditioners). The WISE model also can assess the adequacy of various generation expansion plans. Finally, the dynamic formulation of COAL1 and the Jones model allow them to show how the electric utility industry responds to changing or unstable conditions. REM also should be able to show utility response to unexpected changes as it does not incorporate perfect foresight into its formulation.

RESEARCH NEEDS

Planning Uncertainty

A hierarchy of planning models with some of the key information flows is shown in Figure 3. In the past, utility planning has focused on generation and transmission planning tools. Detailed models have been developed for use in configuring economical systems and assessing their reliability. The results of these models are sensitive to a number of variables, such as system demands, fuel availability, and fuel costs. These variables are generally treated as inputs to the planning models. Thus, an important part of the uncertainty in planning is hidden in the inputs, which are implied to be "knowns".

The next step up the hierarchy in Figure 3 is energy systems models. In the past, these models have not been used extensively in conjunction with utility planning. A survey which included 100 utility companies conducted in conjunction with this regional planning study indicated almost no use of energy systems models at the utility planning level. These models could potentially play an important role in supplying inputs needed for the detailed generation and transmission planning models. However, energy systems models are in turn dependent upon inputs such as population, income, and economic activity. The results of an energy systems model may depend significantly on these inputs.

Regional socio-economic models may in turn be used to provide values for some of the important inputs to energy systems models. Some energy systems models are coupled to such socio-

economic models. In either case, these socio-economic models again require inputs which significantly affect the results.

Thus, it appears that there is a tendency at all levels of planning to "push out" variables which are important in evaluating the accuracy of the planning analysis and treating these variables as inputs. Important planning trade-offs may be hidden in these planning inputs. This discussion is not meant to imply that efforts should not be made to improve the quality of planning models. Rather, it is meant to emphasize the importance of considering the entire planning process and not just the details of specific planning models.

The smooth trends of the past may have lulled us into believing that future conditions can be predicted much more accurately than is possible. Even if models were perfect, natural events, unknown resources, and the unpredictability of human nature result in fundamental limits to planning accuracy. It is essential that the uncertainty inherent in planning be addressed in the planning process.

Energy systems models should include assessments of the uncertainty of their results in their development and utilization. The work conducted by The Futures Group with the ELECTRIC3 model is an example of how this might be done. [1] This work involved changing a number of important parameters and relationships in the ELECTRIC3 model to provide a range of projections rather than single projections. This type of study also needs to be conducted in conjunction with generation and transmission modeling to show how this uncertainty impacts utility plans.

Dealing with Uncertainty

Assessing uncertainty in the planning process is important. Assuming uncertainty is included in planning, the next step is to develop tools which aid the planner in dealing with uncertainty. If planners must operate under uncertain conditions, they need to be able to evaluate the consequences of their actions when they make less than perfect decisions. Modeling techniques which do not assume perfect foresight such as those used in REM, COAL1, the Jones model, OSSIM, and the WISE model, may prove useful for this task.

An example of this concept is seen in the work by Ford, in which the ELECTRIC1 model was used to demonstrate the cost penalty of unexpected changes in load growth. [2] The penalty incurred when the utilities use large plants is compared under identical conditions to when they use smaller plants. The result gives the planner an indication of how some of the adverse impacts of unexpected changes may be mitigated. Another study, conducted by the Stanford Research Institute, was designed to demonstrate the usefulness of including uncertainty and used a simple forecasting model which gave probabilistic

projections. [3] This was followed with an analysis of whether a utility would be better off building fewer plants or more plants than indicated by the mean projections.

These examples demonstrate that there is the possibility of providing planners with tools which will aid them in dealing with uncertainty. Energy systems models which can show the results of "surprises" may find an important use in this area. It is felt by the author that this represents an important area of research in electric utility planning which could prove quite fruitful.

Multi-Utility Models

The discussion in this section so far has made little distinction between utility level planning and regional level planning. Most of the discussion is applicable to both levels. This review is intended, however, to focus on regional planning questions. Regional planning implies multiple utility planning. None of the models reviewed were developed specifically to address multiple utility questions. To the author's knowledge, no other energy systems models have been developed which address these questions.

Generation and transmission models, on the other hand, are sufficiently detailed to address the multiple utility questions. There appears to be a significant discrepancy between the utility definition in energy systems models and generation and transmission planning models. Further complicating the problem, utility boundaries seldom coincide with the regional boundaries used in energy systems models. If energy systems models are to be integrated with generation and transmission models in the planning process, these discrepancies must be addressed. This probably will require developing new models incorporating many of the techniques described in this review, but designed specifically for regional utility questions.

CONCLUSIONS

The objectives of this review were to assess the usefulness of existing energy systems models and modeling techniques for regional electric utility planning and to describe what direction future research should take to improve the value of these models for regional electric utility planning. The models reviewed represent a cross-section of techniques and approaches. As a result, they perform different functions and their application potential varies. Thus, it cannot be said that any one of the models is particularly good or bad for planning when compared to the others.

Three areas where research is needed to improve the value of energy systems models in electric utility planning were identified:

1. The uncertainty inherent in energy systems simulation and its potential impact on the planning process needs to be assessed.
2. Energy systems models designed to assist the planner in dealing with uncertainty are needed.
3. If energy systems models are to be integrated with other planning models, the problem of multi-utility concerns needs to be resolved.

ACKNOWLEDGEMENTS

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The comments, suggestions, and information provided by Dr. Mark Swift, Stanford University, and Dr. Andy Ford, Los Alamos Scientific Laboratory, are appreciated.

TABLE I

Scope of Models Selected for Review

<u>Model</u>	<u>Regional Definition</u>	<u>Modeling Technique(s)</u>	<u>Parts of Energy System Included</u>
REM	Total U.S. disaggregated to 9 regions	Econometrics, Economic and Engineering Analysis	Demand for major energy forms, electricity supply
BNL	Flexible ranging from total U.S. to about one state	Linear Programming	Optimum energy supply configuration for all major energy forms
COAL1	Total U.S.	Systems Dynamics	Supply and demand of major energy forms

TABLE I (Continued)

<u>Model</u>	<u>Regional Definition</u>	<u>Modeling Technique(s)</u>	<u>Parts of Energy System Included</u>
Jones	Approximately one state	Systems Dynamics, Economic and Engineering Analysis	Electricity supply only
OSSIM	State of Oregon with 3 sub-regions	Systems Dynamics, Econometrics, I/O Analysis	Electricity demand only
PIES	Total U.S. disaggregated to 7-15 regions for different aspects	Econometrics, Linear Programming	Supply and demand for all major energy forms
SRI	Total U.S. disaggregated to 6-14 regions for different aspects	Network Analysis	Supply and demand for all major energy forms
WISE	State of Wisconsin	Systems Dynamics, Economic and Engineering Analysis	Supply and demand of all major energy forms, extraction not included

TABLE II

Function of Models Reviewed

<u>Model</u>	<u>Energy Demand</u>	<u>Energy Supply</u>	<u>Economy</u>
REM	Determines demand in each of nine regions of U.S. for the industrial, commercial, and residential sectors. Demand is determined separately for electricity, oil, natural gas, and coal. Demand is price sensitive and consistent with the price calculated for electricity.	Simulates decision making and regulatory process in the electric utility industry to determine electricity supply and price in each of the nine regions.	Energy demand is related to population and income in each region which are inputs.
BNL	Energy demand is input. Demand must be specified by how used (process heat, lighting, etc.)	Energy resources available and their cost are specified. The model allocates these resources through the energy supply system to meet energy demands in an optimum manner.	Not included.
COAL1	Determines demand for oil and gas, coal, and electricity. These demands are price sensitive.	Determines availability and cost of oil and gas, coal, and electricity. The effect of depletion on cost is shown.	Energy demand is related to GNP which is input.

TABLE II (Continued)

<u>Model</u>	<u>Energy Demand</u>	<u>Energy Supply</u>	<u>Economy</u>
Jones	Demand for electricity is input.	Simulates the capacity expansion and energy resource purchasing by the electric utility industry to determine electricity supply and generation cost.	Not Included.
OSSIM	Determines energy demand as a function of electricity and fossil fuel prices.	No energy supplies included.	Overall socio-economic activity of the state is model.
PIES	Price sensitive calculations for energy demand disaggregated by region, economic sector, and fuel are made.	Supplies of each of the major energy resources are made. These are combined through the energy supply network to supply the demands.	Energy demand related to population, income, and other economic variables. Impact of energy system on GNP, investment and other economic variables is shown.
SRI	End use demands are input by region. The model determines what fuels are used to meet the demands.	Resource supply curves are input. A complex network representing the energy processing and transportation system is used to balance supply and demand.	Not included.
WISE	Determines energy demand in the state by physical process, economic sector, and fuel type.	Supplies of energy resources available to the state are input. Electricity supply is calculated in the model.	A set of submodels simulates economic and demographic conditions. These drive the energy demands.

TABLE III.a

How Various Modeling Techniques Are Used in Models Reviewed

<u>Model</u>	<u>Linear Programming</u>	<u>Network Analysis</u>	<u>Systems Dynamics</u>
REM	Not Used	Not Used	Not Used
BNL	Optimum allocation of available energy resources through conversion and transportation to meet end use demands.	Not Used	Not Used
COAL1	Not Used	Not Used	Overall model structure to represent resource depletion, capital formation, and time delays in system.

TABLE III.a(Continued)

<u>Model</u>	<u>Linear Programming</u>	<u>Network Analysis</u>	<u>Systems Dynamics</u>
Jones	Not Used	Not Used	Overall model structure to represent generation capacity, energy resource contracts, and time delays in the system.
OSSIM	Not Used	Not Used	Provides overall structure of model and is used extensively in sub-models, entire model is formulated with systems dynamics nomenclature.
PIES	Allocates energy resources of various kinds in different regions to demands in various regions.	Not Used	Not Used
SRI	Not Used	Connects energy resource supplies to end use demands each in various regions through conversion and transportation processes.	Not Used
WISE	Not Used	Not Used	Provides overall framework of model. This is only in a fairly general sense a systems dynamics model.

TABLE III.b

How Various Modeling Techniques Are Used in Models Reviewed

<u>Model</u>	<u>Input/Output</u>	<u>Econometrics</u>	<u>Economic and Engineering Analysis</u>
REM	Not Used	Energy Demand by region, fuel sector, as function of price.	Detail simulation of industry decisions to determine electricity supply.
BNL	Not Used	Not Used	Not Used
COAL1	Not Used	Used within systems dynamics framework to show demand shifts and investment trade-offs.	Not Used
Jones	Not Used	Not Used	Used within systems dynamics framework to simulate industry capacity expansion and resource contracting decisions.

TABLE III.b(Continued)

<u>Model</u>	<u>Input/Output</u>	<u>Econometrics</u>	<u>Economic and Engineering Analysis</u>
OSSIM	Used in determining manufacturing and service activity in overall model of economy.	Used in electricity demand calculations.	Not Used
PIES	Not Used	Energy demand by region, fuel, as a function of price.	Not Used
SRI	Not Used	Not Used	Not used in model but supply curves reflect economic analysis and "expert opinion".
WISE	Not Used	Not Used	The model is fairly loosely structured and each model is developed with some independence. Most of the more detailed models represent engineering and economic analysis. Others consist largely of constant coefficients.

	REGION			ENERGY SYSTEM					ECONOMY			ENVIRON- MENTAL
	Total U.S.	Multiple Regions	Single Regions	All Energy Supplies	All Energy Demands	Electricity Supply	Electricity Demand	Intermediate Supply System	Driven by Economic Variables	Economy Modeled	Impact on Economy Shown	Environmental Impact Shown
REM	X	X			X	X	X		X			
BNL	X		X			X	X	X				X
COAL1	X			X	X	X	X		X			
Jones			X			X						
OSSIM			X				X		X	X		X
PIES	X	X		X	X	X	X	X	X		X	
SRI	X	X				X	X	X				
WISE			X		X	X	X		X	X		X

Figure 1.

Factors Included in Models.

	REGIONAL			POLICY		PREDICTIVE					TECHNOLOGY		OTHER	
	Total U. S.	Inter-Regional	Single Region	Policies Dealing with Electric Utilities	Impact on Electric Utilities of Other Energy Policy	Load Forecasting	Inter-Regional Load Shifts	Load Characteristics	Fuel Prices	Fuel Availability	End Use Technology	Generation Technology	Evaluation of Generation Expansion	Dynamic Electric Utility Response
REM	X	X		X		X	X							X
BNL	X		X	X	X			X			X	X		
COAL1	X			X	X				X	X				X
Jones			X	X										X
OSSIM			X	X		X								
PIES	X	X		X	X	X	X		X	X				
SRI	X	X		X	X		X		X	X				
WISE			X	X		X		X			X		X	

Figure 2. Electric Utility Planning Applications of Models Reviewed

Figure 3.--Planning Model Hierarchy

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SECTION 7.

SYSTEMS AND PROCESSES

This report depicts three diverse aspects of Regional Power System planning, Decision and System processes. The report consists of three separate aspects of the decision making process and aspects of hardware and software used in making regional planning effort.

The IBM contractor discusses Information Transfer and Decision processes in Long-term regional planning. The goals of the report are to give a self-contained assessment of the status of two aspects of regional planning, regional information systems and decision support systems.

The IBM contractor documented by means of their own survey the ad-hoc planning practices of regional and area level power system groups. They also surveyed the existing software in Data base management systems currently in use (reliability, system analysis and system forecasting). Surveys went to power pools, reliability councils and holding companies of large utilities. The conclusions of the report are based on analysis of the survey results.

Power Technologies explored the region of systems and processes to find objectives and criteria for regional power system planning. Their report contains the existing regional power system planning criteria, the fundamental goals and objectives behind the established criteria and the barriers to attainment of these goals and objectives.

Part I of the report discusses the existing planning criteria used by the utilities and the various groups into which the operating utilities are formed, such as pools and regional councils, pointing out some of the differences.

Part II penetrates behind the planning criteria to explore the goals and objectives that led to the current criteria and practices of the industry.

Part III explains briefly some of the barriers to attainment of the goals and objectives of Part II and indicates paths that may help to pass the barriers.

Part IV describes areas where further work might be usefully applied toward more complete attainment of regional planning of power systems.

Stagg Systems explored the area of hardware and software used to facilitate regional planning in energy as well as other areas requiring regional levels of effort.

The primary objectives of this facet of the research project was to appraise the application and development of graphic systems and computational models for the medium and long-range planning of power systems. The project conducted in pursuit of this objective was one phase of the overall objective of examining the systems and processes available for regional planning of energy supply systems.

The limited objective of the research project was to appraise graphic systems and computational models within the DOE laboratory community as exemplified by the facilities at Argonne National Laboratory (ANL), Lawrence Berkeley Laboratory (LBL), and Oak Ridge National Laboratory (ORNL).

The following activities were carried out in meeting the objectives of this project:

- review applications directed to regional planning
- review available equipment systems
- review available program systems
- review extent of utilization of systems
- review data bases available as well as those required
- review specific systems available at ANL, LBL and ORNL
- prepare a report summarizing all findings.

An essential aspect of the study was to assess future needs for computer-based graphics systems for use in regional planning of energy supply systems. Accordingly, recommendations were made for future research and development activities.

SECTION 7.1

REGIONAL PLANNING OF ENERGY SUPPLY SYSTEMS: INTERACTIVE COMPUTER GRAPHICS AND COMPUTATIONAL MODELS AT SELECTED DOE LABORATORIES

A.H. Palmer

Stagg Systems Inc.

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INTRODUCTION

BACKGROUND

In mid-summer of 1977 the Energy Research and Development Administration (ERDA, at this writing formally a part of The Department of Energy and in future reference in this document DOE) contracted with the University of Oklahoma to provide administrative and technical services in evaluating the state-of-the-art of regional power system planning. A prime contract was issued as Contract Number EC-77-S-05-5466.

A proposal was made originally by the University of Oklahoma School of Electrical Engineering and Computing Sciences. The proposal identified the intention to:

- define the state-of-the-art in regional planning as it pertains to expansion of power systems
- identify research needs so that suitable methodologies can be developed.

The proposal further identified the desire to draw upon an interdisciplinary team of experts to study generation planning, transmission planning, supply/demand models, and systems and processes.

The team of investigators selected to provide services in various facets of the project was composed of universities, utility companies, a manufacturing concern, and consulting firms. The contractors in each of the areas were as follows:

Transmission Planning

- Public Service Electric and Gas Company
- University of Florida
- Power Technologies Inc.

Generation Planning

- Philadelphia Electric Company
- University of Michigan
- Systems Control Inc.

Supply Demand Models

- University of Texas
- Data Resources Inc.
- Montana Energy and MHD Research and Development Institute
- Systems Control Inc.

System and Processes

- International business Machines
- Stagg Systems Inc.
- Power Technologies Inc.

Each of the contractors was instructed to work independently of other contractors for the project.

The contract document is paraphrased here to indicate the areas which the contractors were to focus upon. The contractors were to prepare an assessment of the state-of-the-art for medium and long-range planning of regional power systems. Models were to be defined and critically evaluated for generation planning, transmission planning, and energy supply-demand planning. The inherent assumptions of each model and the limitations of the models were also to be determined. Finally a review was to be made of information transfer and decision making processes.

The specific role of Stagg System Inc. (SSI) was to be as one of the investigators in the Systems and Processes phase of the project. Initially it was intended that SSI would direct its efforts to appraising the state-of-the-art in the application and development of graphic systems for medium and long-range planning of power systems. For several reasons it was subsequently concluded that this evaluation would be restricted to a review of systems and development activities at three DOE facilities, those at Argonne National Laboratory (ANL), Lawrence Berkeley Laboratory, and Oak Ridge National Laboratory (ORNL). The two notable reasons for modifying the nature of the review were:

- recent developments, as evidenced by a DOE-community graphics conference, indicated advances at DOE laboratories.
- a need to avoid too extensive a review of proprietary products and the associated difficulties.

Consequently SSI directed its efforts to appraising the application and development of graphics systems for the medium and long-range planning of power systems. Its limited objective was to review and evaluate those projects at the aforementioned DOE facilities.

STUDY OBJECTIVES

The specific objectives of Stagg Systems Inc. within the overall project should be viewed within the context of the project objectives.

The overall project included:

- A survey of electric utility planning practices
- A comparative analysis of tools for generation planning
- A comparative analysis of tools for transmission planning
- A comparative analysis of electric utility component supply/demand models for planning
- A comparative analysis of systems and processes for regional planning

The primary objective of this facet of the research project was to appraise the application and development of graphic systems and computational models for the medium and long-range planning of power systems. The project conducted in pursuit of this objective was one phase of the overall objective of examining the systems and processes available for regional planning of energy supply systems.

The limited objective of this facet of the research project was to appraise graphic systems and computational models within the DOE laboratory community as exemplified by the facilities at Argonne National Laboratory (ANL), Lawrence Berkeley Laboratory (LBL), and Oak Ridge National Laboratory (ORNL).

The following activities were carried out in meeting the objectives of this project:

- review applications directed to regional planning
- review available equipment systems
- review available program systems
- review extent of utilization of systems
- review data bases available as well as those required
- review specific systems available at ANL, LBL and ORNL
- prepare a report summarizing all findings

An essential aspect of the study was to assess future needs for computer-based graphics systems for use in regional planning of energy supply systems. Accordingly, recommendations were made for future research and development activities.

SCOPE OF PROJECT

The scope of project can be summarized as follows:

- Assemble bibliography of published papers

- Review manufacturer documents
- Assemble DOE facility publications from different laboratories
- Review DOE publications
- Visit DOE facilities at ANL, LBL and ORNL
- Categorize available DOE systems
- Assess DOE use of available technologies
- Describe major systems

Since the limited objective of the project was to focus attention on three specific DOE facilities the emphasis of the project was to review documents and systems originating from those facilities.

In the assembly of references and in the literature search, however, a review was made of systems within the electric utility industry as well as DOE facilities other than those visited. Accordingly this report briefly describes graphics based systems and computational models for regional planning within the electric power industry along with those used within the DOE community.

A review was made of manufacturer literature to identify equipment available in the marketplace today and to gain an insight into future marketplace systems. While this review was made, it was done more to highlight the types of systems than to perform a comprehensive review of available capabilities.

A number of publications originating in DOE facilities were reviewed. All those which could be obtained within the limitations of time were reviewed.

Three of the DOE facilities, those at ANL, LBL, and ORNL were visited and a number of interviews were conducted with DOE staff members to assess the use and potential of graphics based systems. These interviews were focussed on applications and systems. Following the field visits an effort was made to identify the major systems, both those available and those under development. An assessment was made of the use of graphics-based systems in application developments and DOE projects

METHODOLOGY

Initially several representatives at four DOE laboratories were identified by the DOE project advisor as DOE staff members working in the area of computer-based graphic systems. These staff members served as a point of departure for reaching into DOE and obtaining access to published materials and

other available information.

Telephone interviews were conducted with these staff members and other staff members. As a result of these telephone interviews a set of publications was obtained and an information base established.

A literature search was performed using available journals and proceedings covering electric power system publications. In addition a literature scan of DOE publications identified other available documents. Document review of the available publications served to identify the DOE staff members which were to be interviewed during field visits.

Field visits were made to laboratories identified earlier and interviews were conducted. An attempt was made to meet with 8 to 10 staff members at each facility and to subdivide interviews between application users (planning practitioners) and application implementers (systems and programming personnel). An effort was also made to review overall capabilities with senior DOE staff. One important aspect of the interviews was to focus attention of the DOE community on future needs. The interviews afforded a first-hand opportunity to assess future needs and to obtain individual comments regarding such needs.

Following the field visits some additional DOE documents were obtained and reviewed. The major systems available at each of the laboratories were then identified.

The major systems (and types of systems) available and in use within the power industry were identified from available literature and an understanding of the industry.

A final report outline was prepared and a final report was written. It is noteworthy that, while many systems are in some measure of use or in the development stage, relatively little documentation is available regarding such systems.

DEFINITIONS

It is essential that some of the terminology used in this report be defined so that readers with different perspectives may have a common frame of reference. It is especially important since the phrase "regional planning" has different connotations to electric utility industry personnel than to DOE community personnel

This particular project itself, from its inception to its completion, assumed a different definition for the term planning.

In this section a brief definition is given for the following terms:

- regional planning
- power system
- planning horizon
- computer interactive graphics
- equipment systems (hardware)
- program systems (software)
- applications
- plan selection (optimization)

Regional planning should be defined in terms of its two component words. A region may be considered to be as little as two or more electric power companies (or agencies) and as much as a significant portion of the country. Planning includes the development of energy supply system expansion plans and the implication of such plans on regional resource utilization. Planning also includes assessment of the impact of system expansion.

While the foregoing definition has not indicated the point of interest of a user of a given application it is useful to make some distinctions. From the vantage point of a utility company, the development of alternative plans, the selection of one plan and the implementation of the plan are within the purview of the company. From the viewpoint of the practitioner within the DOE community it might be more appropriate to describe planning as an assessment or evaluation of a hypothesized set of conditions.

Power systems should be viewed as the composite source of energy supply. They would include generation facilities, transmission facilities, distribution facilities, fuel supply, and energy storage facilities.

The planning horizon considered within the context of this study spans a period of from five to fifteen years from the present. This would traditionally be characterized as intermediate to long-range planning.

Computer interactive graphics systems are comprised of:

- a component with calculation and logic capability
- a component which depicts the results of processing in a graphic fashion
- a component which allows user communication and interaction with the calculation and graphic display capability.

While the greatest capability may be available where all three components are part of the system, many processes are quite adequately served by systems with only two components available.

Equipment systems (hardware) are generally the tangible elements of the above-described computer interactive systems.

Program systems (software) are the programs which make the foregoing equipment systems function. These program systems may be an application, graphic support services package, or data base management services.

Throughout this document reference will be made to applications. The word application will be used to subsume a wide range of program systems which individually include the utilization of interactive computer-graphics technology. This technology includes both the equipment and the supportive programming capability. The applications include the following:

- power plant siting
- transmission system siting
- air quality studies
- water quality studies
- fuel resource studies
- land use analysis
- aesthetic impact analysis
- socio-economic impact studies
- biomedical impact analysis
- regional resource studies

At times the word application will be used to indicate a program system. At other times it will be used to indicate a methodology which may, in part or in total, have been implemented as a program system. License is taken to use as wide a construction as possible on the word "application". It is clear that the intention is to indicate more than a computer program or the use of a computer program.

Plan selection (optimization) describes the process by which alternative plans are evaluated and a selection made. One reason for highlighting this term in this section of the report is to draw attention to the selection basis. The basis for selection varies considerably from one planner to another contingent upon the agency performing the planning and selection.

OVERVIEW

SUMMARY

This summary must begin with a statement regarding the nature of the environment which the study faced. The Department of Energy itself is passing through a significant period of organization. Both in Washington and at the various DOE facilities throughout the country it is evident that this organization is facing new problems in new areas of attention. Perhaps as a consequence of this state the organizational arrangement within the laboratory appears unstructured.

Relative to the electric power industry, DOE appears to have a significantly different viewpoint when it focuses on the regional planning process. While the electric power industry plans expansion of energy supply systems, the emphasis within DOE is the planned use of and impact on regional resources.

Highlights

As a result of the literature review and, more strikingly, as a result of the field visits (and telephone conversations) several aspects of systems and processes as manifested in interactive graphic systems become clear.

A facet of application and support systems currently in use and under development is the apparent unplanned nature of the applications and supporting systems. Most systems seem to be addressing specific immediate needs without addressing long-term planning needs of the DOE community.

The emerging needs of the DOE community are only now taking on some form and may lead to coherent systems for use at the local, state, regional, and federal levels. To date, the overlapping needs at these several levels has not generally been reflected into the design and availability of the systems.

There is, however, a shared concern for the availability of data of a reliable nature, for the different studies to be conducted. A basis for virtually all studies conducted is a supply of data conveniently available in a processable medium. While data bases are being built, and to some extent shared, they are generally built to meet the needs of a specific area.

Concurrent with the concern for data is a common recognition of the need for computational models and graphic system. This recognition of need has been translated into projects which allow a user to automatically prepare graphic depictions of data, and the results of processing with analytical tools. Such systems range widely from simple semi-graphic plots on computer-printer to sophisticated man-machine interactive systems to prepare graphic displays.

This variation in level of capability available to the planning practitioner is evident within each laboratory as well as between laboratories. Significantly, many of the available facilities and capabilities are still seeking uses.

The use of such capabilities is extremely applicable to the regional planning process as it appears to be viewed by the DOE community. The evaluation of plans for energy supply systems and the study of the impact on regional resources are enhanced by the utilization of computer-based graphic systems.

Bibliography Review

A large number of DOE laboratory reports have been published identifying the projects which are being conducted at the laboratories. The reports cover a range of projects and include:

- regional planning and assessment studies
- graphic systems descriptions
- data base system descriptions

In general the reports describe specific studies or systems. Some literature, however, does describe systems with a variety of alternative available programs for production of graphic results. A set of references for DOE laboratory reports is provided at the end of this report.

During the initial phase of the overall project, The University of Oklahoma compiled a survey of tools currently in use within the electric power industry and by consulting firms. The survey focused on analytical tools and models and did not specifically request information regarding the graphic capability inherent in some of these systems.

A review was made of the technical literature impinging upon the area of electric power system planning and the

application of computer based graphic systems. This review did identify some available graphics-based systems and references are provided at the end of this report.

Current Utilization

In the several laboratories which were visited, computer based graphic systems were available. Capability was generally available at various levels and although the more sophisticated systems were less available on a day-to-day basis to any prospective user, a basic level of graphics was available.

The exposure to such a capability varied widely. In several instances, personnel responsible for planning activities were not fully cognizant of the available capability although staff members dedicated to supporting the systems were anxious to promote use of the facilities. As anticipated, use varied greatly and facilities were used in quite different ways depending upon the user. In some instances intermediate staff members were used to write custom programs to produce results. In other cases systems were built to support and work with a given planning activity.

A variety of scientists and engineers is currently employed within the laboratories. The backgrounds of the staff member are quite different both academically and by employment experience. The interdisciplinary nature of such a staff would in part account for the apparent difference in utilization of the available systems.

Available Technology

The current marketplace exhibits a wide variety of computer based graphics systems. Systems are available to prepare graphic data representations by means of computer printer, plotter, microfilm, microfiche, and a variety of video displays. Systems are available also for digitization of graphic data, and for user interaction by means of a tablet, light-pen, joy-stick, trackball or function keys.

These devices are currently in use in different assemblies both in the electric power industry and at DOE laboratories. The extent of use of some of these systems is significantly less than in the use of general purpose digital computer systems.

within the DOE laboratories funding for such systems is generally made on a specific project basis. Frequently the situation arises in which the absence of a single project to support funding results in the unavailability of equipment even though several projects together could support this equipment.

In most instances the graphic system support programming, software which allows use of the equipment at a basic level, is available from the manufacturer. While the rudimentary software is available, however, it falls to the lot of individual users (laboratories) to provide a framework or system of programs to allow planning applications to be developed and to make good use of available equipment systems. Such an effort is being made at the various DOE facilities.

The primary emphasis of the groups performing the development of systems has been in developing the capability to depict data and the results of calculations graphically. Less effort is being expended in permitting truly interactive computational graphics for planning applications.

Industry Systems

A literature search has indicated that presently available planning systems used by the electric power industry focus on the general areas of generation and transmission facility planning. The available program applications fall in the category of steady state network models of the electrical system with a model of the higher voltage transmission network, and the load and generation. This is a type of tool used almost universally by the industry in primary system expansion planning. In addition, to a lesser extent, there are available models for simulating dynamic network behavior.

Both the steady state and transient analysis systems are available with various forms or degrees of graphic interactive systems.

DOE Laboratory Systems

A much wider variety of systems and applications is available within the DOE community. This stems primarily from the requests made of DOE staff members for specific answers to questions regarding a wide range of policy decisions. In general comprehensive systems for use in regional planning have not been devised. Instead a

wide range of individual ad hoc applications have been developed. In some cases these have matured to more comprehensive systems as a result of the natural succession of studies and needs for results.

One area which has had extensive commitment is that of data base development. This area has witnessed significant progress in compilation of data bases, both in the variety of available statistics and in the depth of such statistics. A commitment is being made at each of the laboratories to providing this basic prerequisite for new developments.

A second area which has had extensive commitment is that of graphics support systems. Individual display packages have been purchased or developed and made available for use. In the laboratories such graphics capability is reasonably documented and use of the capability is encouraged.

In each of the two areas noted above, data base support systems and graphics support systems, recognition has been given to the needs for these capabilities. A very high level of activity is also directed to the development of tools for regional planning. Current and past developments have focused on individual, specific, and fairly parochial studies to address a narrow question. As a result of study time constraints and the scope of the evaluation itself such studies make only sporadic use of the available technology.

CONCLUSIONS

While this study has focussed upon the role of interactive computer graphics within the regional planning process of energy supply systems, a number of questions arose which peripherally relate to the subject matter. Conclusions to these questions are presented here with a remark that the conclusions presented are reflections of several activities and conditions:

- Brief visits to the laboratories with discussions primarily with accessible staff members
- A review of published material which itself is available in different degrees from different laboratories
- An outlook conditioned by industry approaches to regional planning.

It should be noted that the perspective changed considerably during various stages

of the study and took on a form more sympathetic to a broader scope in conception of the regional planning function.

General

Within the laboratories, the conception of regional planning is very largely one of concern over regional resources whether they be air, water, fuels, land-use or other related regional resources. Within the industry the question is primarily one of optimal siting (and timing) of facilities. This process, while giving some attention to resources is more concerned with economy and reliability of energy supply and has a different emphasis in its implicit objective function.

The differing emphases are reflected in the different models currently being used or developed. The industry is more likely to have electrical network simulation and reliability models whereas the DOE laboratories are more likely to be working on siting models, air-transport models, water supply models, land-use models, or impact analysis models.

It appears that, in time, the vantage points of each of the two groups will move closer together. Certainly, it is likely that the industry will make more extensive use of regional models such as those cited above as the interest of DOE laboratories. To the extent that the industry uses such models it appears that the primary interest will be less of a planning nature than of meeting a threshold requirement for a planned facility.

It must be concluded that the use of interactive computer graphics can facilitate the regional planning process whatever the perspective of the practitioner. In its most rudimentary manifestation, the preparation of graphic depiction of tabular or numeric data, assimilation of information is clearly enhanced.

In the planning process, a complex one involving many variables and constraints, graphic depiction of data results in a clearer understanding of the relationships. This is particularly true when the data being depicted is residual from calculations, including analyses performed for parametric or sensitivity analysis. To "close the loop" and permit user interaction in such evaluations is useful and improves the understanding of the planning and modelling process.

One question which has a tendency to arise from time-to-time is the question of whether there should be a "grand design" (or a set of integrated submodels) which encompasses the entire planning process. Whether one views this question from an industry standpoint or a DOE laboratory standpoint, the availability of such a comprehensive tool appears very attractive. When the analytical requirements, the data needs, and the practical aspects of the process are considered in the light of this question, it becomes evident that such a system of models would be extremely difficult to formalize and the total system would contain complexity unwarranted by the nature of the planning process.

Although the construction of such an all-encompassing model does not appear to be practical, it would be useful to formalize a methodology for a building-block approach consisting of simple basic submodels relating to specific aspects of the overall planning process.

It appears that at present there is substantial capability and development at each laboratory visited. Relatively little, however, seems to be planned or currently undergoing development on an interlaboratory basis. Each of the laboratories is pursuing developments along lines historically pursued by the individual laboratory and with varying approaches to the area of interactive graphics. It would be appropriate to summarize the approach to graphics of the three laboratories with the following dominant emphasis.

- Argonne - make available to the user an array of program services and subroutines which can be used for graphic depiction of data
- Lawrence - make available to the user packaged interpretive systems to allow interactive data manipulation and display
- Oak Ridge - make available to the user an array of subsystems and subprograms through the services of a programmer or analyst.

User Environment

Just as there is evident a different approach to interactive graphics, so too the personnel concerned with regional planning at each of the laboratories are presented with quite different capabilities to prepare graphic results or to interact with graphic systems.

Within the laboratories applications (of the regional planning process) generally are developed in response to very specific relatively short term requests. Such requests may arise at a political level or in response to agency requests for a study. From the viewpoint of this study the evident applications were largely developed for short term utilization with demands for immediate answers a high priority item. Consequently, the application systems devised were not designed for longer term utilization, nor were they placed on an implementation schedule which would allow development of a highly interactive modelling procedure. Frequently, a programmer was the interface between the user and the preparation of graphic results. Infrequently was the regional planning staff interactively performing planning studies with a responsive graphics based system.

Within the utility industry use is emerging of the tool most frequently used as the basis for electrical network planning studies. Interactive graphics-based systems are being utilized and appear to be gaining acceptance.

Within the DOE laboratories the diversity of applications is evident and consequently no single application is focussed upon for application of funding for long term utilization. When one considers the range of applications such as power plant site evaluation, transmission system site evaluation, air quality studies, water quantity studies, fuel resource studies, land-use analysis, aesthetic impact analysis, socio-economic impact analysis, and various other regional factors, it is evident that the scope of application is quite a wide one and demands for individual application funding is diffused.

Equipment Systems

The marketplace today offers a variety of graphic display and interactive devices. Technology has progressed to the point at which utilization of graphic systems is commonplace as a result of established technical and economic feasibility.

At each of the laboratories a representative array of equipment is available for use and is being utilized. The graphic systems are supported by computer systems which give users the capability to perform modelling and to store and retrieve data.

There is some interest at the

laboratories in application of automatic scanning systems. While limited use has been made of these (generally customized) systems, there is some application in their use as data collectors or data base building systems. Particularly when large data bases of physical data, available in a graphic form, are to be built such systems have an advantage. It appears, however, that a heavy investment must be made in editing of data acquired in such a fashion.

Data Bases

Each laboratory is establishing large data bases. The components of these data bases are similar, although each laboratory has a regional responsibility for the area in which it is located. Thus although there may be limited redundancy of data there is a responsibility to prepare files and maintain files which is being met at each of the laboratories.

While some sharing of data files is possible there is no evident plan for sharing in the preparation of files or in devising common data base management systems for maintenance of such data. It must be concluded that a common data base structure along with common retrieval and storage services would facilitate data interchange between laboratories and make needed data available more readily to users.

The laboratories do, to a limited extent, make use of commercially available data base management systems.

Support Programming Systems

Support programming systems are available at each laboratory which allows users to prepare charts, displays and diagrams. Such support is very basic and in general requires some knowledge of programming systems and equipment.

On a higher level there are available at the laboratories some types of interpretive systems. Such systems as typified by CHART [35] allow a user, unsophisticated in computer technology, to prepare graphic data displays interactively. Such systems are highly useful in attempting to assimilate data, whether such data is directly from a historical file, or calculated by a processing application. The availability of such a system, negates the need for the casual application user of systems.

On a third level there are available systems which contain both the application modelling capability as well as interactive graphics capability. Such a system is typified by the interactive flow as used within the power industry. Such a system relieves the application user entirely of any programming responsibilities.

It appears that there is a need for all three of the levels described above. Open-ended flexibility is the advantage of the low level capability while a completely prespecified application is available to the user at the third (highest) level of capability.

RECOMMENDATIONS

These recommendations are based upon needs made evident as a result of visits to laboratories and review of published papers. While they represent the thinking of the principal investigator, they also attempt to reflect recommendations of some laboratory personnel. The recommendations are directed to several primary areas of future development.

1. Development of a long-term plan for regional planning application areas.
2. Exploitation and further use of available laboratory graphic system resources.
3. Expansion of capabilities for special purpose planning studies and analyses.
4. Development of a plan for DOE laboratory interaction, and shared use and development of regional planning systems.
5. Support of regional planning system development by availability of resources and funding of new systems.
6. Distribution of information describing graphic systems, computational models and data bases.

The recommendations are detailed in the following paragraphs.

1. Development of A Long-Term Plan For Regional Planning Application Areas

It is recommended that a long-te

plan be established for the development, on a building-block basis, of a variety of applications pertaining to the regional planning process. A study should be conducted to finalize such a plan and would include the following activities:

- determination of current and future regional planning application needs
- determination of data base requirements
- determination of needs for interactive graphics systems
- definition of the scope of applications (each building block), the analytical techniques to be used, the data requirements, and the possible linkages with other applications
- development of a schedule for implementation of the building blocks of applications, the data bases, and the interactive graphics capability to be developed
- development of budget and manpower requirements to support the project
- allocation of responsibilities for project by laboratory and/or vendors

It should be stated here that this recommendation is not proposing development of a single integrated model. Instead its direction is development of a set of models, each addressing specific areas, which could be used by one or more laboratories or by other governmental agencies.

The use of a building block approach will permit use of the applications directly for the problem of interest and also will facilitate special planning studies for which the basic applications could be modified.

2. Exploitation And Further Use Of Available Laboratory Graphic System Resources.

While each laboratory has available an array of graphic systems equipment, graphic support programs, and data bases, there remain some impediments to convenient and casual use of graphics systems. Two aspects of this problem area can be identified.

The simpler one to solve requires that a 'selling' or promotional activity be instituted to raise application user awareness of the capabilities inherent in available systems. Further, it is recommended that applications development staff be educated regarding the use of

support systems. In this way, the application staff can make decisions regarding the use of graphics in future development.

A more difficult facet of the problem of further exploitation is to place a set of tools, some already under development, at the direct disposal of the ultimate user. In some measure this recommendation involves generalization of developments already being undertaken and to enhance those capabilities by the merging of a set of user data with the tools for graphic data presentation in an interactive mode.

The cost of implementation of this recommendation is small considering the availability of a large part of the support programming systems and equipment.

3. Expansion of Capabilities For Special Purpose Planning Studies And Analyses

It appears that the laboratories will continue to service requests from various governmental agencies. These requests in the past have frequently been directed to specific problems and have been of a short term or ad hoc nature. It is recommended that graphic systems be developed and supported to readily accommodate such analyses.

Particularly when such studies are performed, the presentation of the results of studies loses significance where data is prepared in tabular form. The ready assimilation of the findings of a study are increased by use of graphic methods. To facilitate preparation of graphic results, on a short-term study, requires a high degree of support capability so that the application staff, in preparation of the study, can concentrate on the application. The graphics support, under such constraints would most likely be interpretive and should not require significant program development. In essence this recommendation would place the user closer to the graphic capability.

4. Development Of A Plan for DOE Laboratory Interaction And Shared Use And Development Of Regional Planning Systems

While the individual laboratories have been in existence for some time, the Department of Energy is still in its infancy as an agency and is continuing to assume form. Therefore much of the equipment, program support and data bases at the laboratories are residual from earlier programs and activities.

At the present time developments are proceeding along the lines of projects which are primarily DOE funded and which support the new applications, data bases, and graphics systems. Relatively little interaction is evident between laboratories to eliminate duplicate efforts.

It is therefore recommended that future planning of system development be coordinated between the laboratories to the extent appropriate to the activity. In those situations in which a given laboratory plays a dominant or exclusive role in an application area it would be appropriate for it to support all development. On the other hand there are a significant number of applications and support systems which are being pursued by individual laboratories independently. In such instances, particularly when needs are similar at two or more laboratories, the developments could be shared.

This recommendation can be implemented at several levels:

- planning of new systems on a joint basis
- development of new systems on a joint basis
- timely distribution of systems, data bases and documentation

5. Support Of System Development By Availability Of Resources And Funding Of New Systems.

To facilitate implementation of the foregoing recommendations it is critical that recognition be given to the resources required. These include:

- computers
- graphics systems (equipment and programs)
- data bases

The rationale of funding of such resources on a project basis at times leads to difficulties. The rejection of a request for a resource may be the direct result of there not being a single project available to support the request. On the other hand there may be several projects which together could support such a request.

It is recommended that procedures be established to facilitate upgrading of graphics systems on a multi-project basis.

It should be noted that in times of high technology change, as in the area of graphic systems, change-out of equipment occurs at a rapid rate. While a sound

basis for equipment selection is necessary, projections of life of the system should be conservatively short.

6. Distribution Of Information Describing Graphic Systems, Computational Models And Data bases.

It is recommended that the systems developed at DOE laboratories be made generally available. Information should be distributed indicating:

- techniques utilized
- studies performed
- available program systems
- available data bases

Such a technology transfer and dissemination of information would benefit the industry and the laboratories and could be handled by presentations at technical and professional symposia, by publications of DOE, and by publications of various professional societies.

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OBJECTIVES AND CRITERIA FOR REGIONAL POWER SYSTEM PLANNING

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GENERALPurpose

This report concerns the existing regional power system planning criteria, the fundamental goals and objectives behind the established criteria and the barriers to attainment of these goals and objectives.

Part I of the report discusses the existing planning criteria used by the utilities and the various groups into which the operating utilities are formed, such as pools and regional councils, pointing out some of the differences.

Part II penetrates behind the planning criteria to explore the goals and objectives that led to the current criteria and practices of the industry.

Part III explains briefly some of the barriers to attainment of the goals and objectives of Part II and indicates paths that may help to pass the barriers.

Part IV describes areas where further work might be usefully applied toward more complete attainment of regional planning of power systems.

Introduction

At the present time planning for development of utility facilities is done primarily at the individual utility level. These individual plans are then reviewed by larger groups of utilities such as pool or reliability councils to determine if they fit together and meet the requirements of the entire region. Where conflicts or weaknesses are discovered, the individual utilities make changes which are again reviewed by the group. As a general rule the pools and reliability councils do no planning. Their function is to review the individual plans and suggest areas that need changes.

There are exceptional occasions where the larger groups do specific planning. For example, if a large plant is to be shared by several utilities, the evaluation and transmission arrangements may be studied by the group as a whole with each utility contributing information as suitable to the problem.

In some pools where cooperation has existed for many years some coordinated planning takes place as a normal procedure. Committees study the long range needs of the pool and the individual companies then develop their plans in accord with the indicated needs. However, this is not a standard procedure throughout the industry.

The normal process is somewhat cumbersome, requiring as it does, the developments of plans by companies, their review by a group and changes by companies with iterations as needed. Even then there is no guarantee the true needs of the region will be met with no unnecessary facilities installed, particularly in areas where the reviewing groups are relatively weak in organization. If the reviewing group is a reliability council, there may be little economic incentive for the group to devise plans having the lowest revenue requirement. The councils are charged mainly with insuring that at least minimum standards of service are met with no direct responsibility for costs. If the reviewing group is a pool, there may be more incentive to insure a minimum revenue requirement because the savings may be shared among the members.

I. CURRENT RELIABILITY CRITERIA

Each of the nine councils* of the National Electric Reliability Council has prepared a set of criteria for the testing and evaluation of proposed system development of the individual councils. Copies of the nine criteria are included in the appendix along with some comparisons of features because of their differences (or similarities, in some cases).

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- *ECAR - East Central Area Reliability
Coordination Agreement
 - ERCOT - Electric Reliability Council of Texas
 - MAAC - Mid-Atlantic Area Council
 - MAIN - Mid-America Interpool Network
 - MARCA - Mid-Continent Area Reliability
Coordination Agreement
 - NPCC - Northeast Power Coordinating Council
 - SERC - Southeastern Electric Reliability
Council
 - SPP - Southwest Power Pool
 - SWCC - Western States Coordinating Council

There is a great variation in the criteria. In wordiness they vary from three inches for ERCOT over forty for WSCC. In coverage they range from very detailed to very general. Some give detailed specifications of what events the system shall be designated to survive, while others give sets of tests that will be made to determine the effects with no indication of which ones the system will be built to survive. A number include a series of general statements of good planning practices, including such phrases as "balanced relationships," "excessive risk," or "unduly complicated" but with no definition of the meaning. One (SPP) includes several design features of power plants that affect reliability.

Some of these differences in coverage may arise simply because there are other documents that specify planning principles and accepted practices. More collections of regional standards and practices are available in the responses of the councils to the FPC (Now FERC) Order 383-3 Docket R-362.

Few individual utilities have made such principles part of the public record. An exception is the Pennsylvania Power & Light Company which has given the Pennsylvania Public Utility Commission a copy of their written principles. There may be others not known to this author.

In addition to these few written principles there is a large body of unwritten standards for planning that are generally accepted by the utilities. These provide for much the same type of coverage as the regional council criteria of WSCC, MAAC, MARCA and NPCC that specify the system shall be designed to survive without loss of any load for certain specific failures and combinations of failures. There are countless minor variations and some major ones, resulting from local differences in circumstances. More about the reasons for the differences will be given in Section II.

A. Installed Generation Capacity Requirements

A comparison of the criteria for the amount of generating capacity that should be installed is given in Table I in the appendix. ECAR, MAIN, SERC, and WSCC are not included in the table because they do not have such standards in their criteria. This does not mean there are not such standards for these groups. Separate documents or practices cover the material.

ERCOT provides for a fixed percentage of the estimated annual peak load. MARCA and SPP provide a fixed percentage with provision to check and change the figure if probability calculations show a need for more or less reserve. MAAC and NPCC use calculated probability of loss of load with no fixed percentage reserve specified.

All those who use a probability calculation use a standard of one day in ten years as a minimum acceptable degree of reliability. In NPCC the standard is applied to each of the four areas without consideration of support available through

the ties between the areas and to the outside world. Thus the calculated overall reliability of the combined areas is much greater than the standard.

The criteria also list the factors that are considered in the calculation of the probability of loss of load. These vary among the groups but it is not certain there is truly much difference in the factors. It is more probable the criteria are loosely written.

B. Transmission Planning Criteria

The standards given in each of the council's criteria are summarized graphically in the appendix in Table 2. A tabular form similar to that included in the WSCC criteria is used. However, the format and definitions are different and WSCC is not repeated.

One common concept is apparent from comparison of the tabulations. For the contingencies that are less credible, none of the councils plan to provide a system that will always survive without loss of load. The consequences are observed by test but the criteria do not say the events "shall" be survived without loss of load. Some do not even say that cascading cannot occur, only that it should not be widespread or it should be minimized. There is no definition of "widespread" or "minimized."

Some councils have definite contingencies against which the system shall be planned, designed, and operated so as to avoid loss of load. Then certain other less credible contingencies are specified as ones against which the system will be tested and evaluated. The implication is clear that these less credible events may cause outages and even cascading. The words "minimize the spread" or "disturbance beyond what reasonably can be expected" and so forth clearly show an intention to investigate to avoid surprises. It also shows a recognition that some risks must be taken to avoid system development costs in excess of what is justified by the relative improvement of service to the customers.

A very clear difference in standards for reliability is apparent in the regional criteria of WSCC compared to those of MAAC and NPCC. The U.S. portion of the load of WSCC is about the same as the combined U.S. load of the two eastern groups. Yet the eastern councils provide a much higher standard of reliability than WSCC. In the eastern area there is no mention of dropping interruptible load or generation as an acceptable means of controlling spread of a disturbance. WSCC uses these practices (performance level B) for the condition of one line failing with the system readjusted after prior loss of another line. Also with the system normal the eastern councils plan to survive the loss of a bus section without unacceptable voltages or overloads. WSCC allows dropping of load or generation.

These criteria of WSCC are a recognition of the fact that the probable frequency of such events is low and the cost of guarding against them is very high. In an area such as WSCC the distances between substations are long compared to the eastern companies. So the cost of additional lines or intermediate substations becomes an unreasonable expenditure if only needed rarely. In the east the distances are short and substations are needed at close spacing to carry the loads over lower voltage lines to distribution substations. More lines are needed for thermal capability also. Thus loss of a line or a bus section does not remove such a large piece of the system's transmission capability. Since the lines are needed for capacity anyway, the extra cost to guard against the outage of two lines or a bus section is relatively small.

Obviously the decision of how much reliability to provide is one that requires exercise of much judgment. The incremental costs can be high and the incremental benefits to the customers may be marginal. A careful balancing of the increased cost to the customer and the increased value of the reliability is required.

C. Network Transfer Capabilities

Three of the councils (MAAC, NPCC and MAIN) define the amounts of power the network can be allowed to carry under certain conditions. (All nine use the concepts except ERCOT which has no external ties.) The definitions are relatively close but the titles could be improved. Two councils call the amount that can be transferred day in and day out (for economy type transactions, for example) the "extended transfer capability." To the other this is "normal transfer capability." For the amounts that can be transferred under certain specified emergency conditions, all three have the words "emergency transfer capability or capacity" in the title. Only the order of words is different. NERC, in its annual review, calls this the "emergency transfer capability." It would be useful to reach common titles and definitions to improve the reliability of understanding in inter-council use.

II. GOALS AND OBJECTIVES

To understand the reasons behind the established planning and operating standards of the utilities, it is necessary to know the overall aim of the utilities. In very few words, the aim might be stated "To provide adequate service" at a reasonable cost." "Adequate service" and "reasonable cost" both require further explanation.

Reasonable cost has two primary aspects of importance here. The first is from the customer's viewpoint. The cost of electricity cannot be too high or other sources of energy will be substituted in spite of the great convenience of electricity. From the company's viewpoint the price must be high enough to pay all the costs of supplying the service.

Adequate service also has several ramifications. First, the voltage supplied the customers must be within certain prescribed limits so the equipment will work properly. Second, the reliability must be acceptable. Unfortunately, there is no standard definition of acceptable. Even within the same company reliability of service to customers will vary from one part of the system to another. The best insight to this subject perhaps can be obtained from the following introduction to a set of planning principles used by a practicing utility, Pennsylvania Power & Light Company.

INTRODUCTION

These reliability principles and practices provide a guide to orderly economical development and operation of an adequate system with sufficient flexibility to meet future needs. They will be amended and expanded from time to time as necessary to meet changing economic and social conditions.

The principles recognize that:

1. Electric service must be provided at a price the customer is willing to pay in a competitive market.
2. A higher degree of service reliability is required as the territory becomes more dependent on electricity.
3. Large scale or long term interruptions are especially to be avoided because of the adverse effects on and hazards to the public.

The practices outlined are based on industry wide experience with failures in the past and an estimation that future performance will show improvement as experience is gained and facilities are redesigned.

The practices are also directed towards restricting the frequency of interruptions according to number of customers (or kilowatts) interrupted and the time required to restore service; the more severe interruptions to be less frequent. There is presently no specific, generally agreed upon set of figures that define an acceptable relationship between severity and frequency of occurrence. To some extent this is affected by the cost of improvement.

Also, as a direct consequence, the various segments of the supply have varying degrees of reliability.

The Area supply system (12 kV) provides reliable service although outage of any line will usually interrupt some small amount of load until switching and repairs can restore all service.

The Regional supply system (66 kV) is more reliable in that outage of two related facilities usually must occur before load is dropped. However, for direct supply to area substations, outage of a single line may interrupt limited amounts of load

until switching or repairs can restore supply. The Bulk system (500 and 230 kV) has the highest standards and provides generally for at least two lines, in addition to normal maintenance, without loss of major loads.

These principles and practices are not to be followed blindly. There are many circumstances where intelligent deviations must be made. However, such deviations should be fully justified and explained so the individual practice does not become a standard by default.

A study of these principles and practices will make apparent that in order to keep the cost of electricity competitive, some risk of interruption must be taken. Their purpose is to insure that the risks taken are properly proportioned and that all understand what risks are accepted.

A study of this excerpt makes it very obvious that the degree of reliability provided is affected by the cost to provide it. This is not characteristic of utilities alone. All kinds of services are more frequent, available, or reliable in closely builtup areas than in rural areas.

Another factor leading to differences in criteria is the degree of cooperation the members of a council have been in the habit of exercising. ERCOT is the outstanding example of one where the past history has been one of minor interchange of energy. The distances are great and the costs of fuel for all the companies have not been greatly different while gas was available for use in boilers. This situation may change as fuel supplies and prices change.

Some of the differences in the council criteria are deliberate. Definite principles are omitted to avoid potential complaints. If definite, as pointed out earlier, it may be necessary from time to time to deviate from planning principles. However, if the principles are written for everybody to study, deviations may lead to complaints from customers who feel they are being discriminated against because they do not have two line service. It is nearly impossible to place in the principles the judgment necessary to show why one area should have two line supply while another should not. This is particularly true if the chief reason for the difference is the cost of the second source.

One of the primary goals of criteria for planning and operating is the reduction of costs of supplying service. Criteria establish minimum acceptable standards of voltage and reliability that must be met. If the utility provides service much in excess of the standards, the cost of the facilities is increased. There may be operating savings that justify the extra facilities in some cases. Careful cost evaluations must be made. There may be occasions where service that is below the standard is provided because the cost of improvement is too high. Usually such situations

are temporary in nature pending completion of another major facility to supply a given area in the near future.

III. BARRIERS TO ATTAINMENT OF GOALS

One of the chief barriers to planning of electric power facilities on a regional basis is the difficulty of identifying the restrictions imposed by minor problem spots as already mentioned. However, since the chief goal of regional planning is attainment of adequate service at a reasonable price, any method that reduces costs while improving reliability should be encouraged and used. One of the most effective cost reduction methods is the formation of operating pools which is also a step toward coordinated planning on a regional basis. There are many barriers to the formation of such cost saving groups. This section of the report discusses advantages of pools, types of arrangements made, and some of the problems that act to prevent pool formation.

WHY UTILITIES FORM GROUPS

A. Operating Savings

The primary reasons utilities form into operating groups are economic. The savings available from coordination of operation of two or more systems are large, immediately available, and measurable.

These savings arise from three interrelated factors:

1. The generation of the combined energy requirements on the most economical generating units available.
2. A reduction in the amount of generation that must be spinning to act as a reserve against loss of capacity or larger-than-estimated load.
3. Smaller requirements for changes in output per generator to meet the requirements for regulating the frequency of the interconnected system.

B. Service Quality

With interconnection of systems there is normally an improvement in the quality of service. The primary reason is the diversity of failures of generating equipment. Isolated systems are subject to possible loss of load for each loss of a large generator on the system. As more systems join together, there is more available capacity to cover the loss of the larger units. While there is more of a chance that some unit will fail with the increased number of units, the probability that the failures will overlap is relatively low.

In addition, there is a diversity of probability of loss of the primary energy supply. If all the companies have exactly the same basic sources of energy (fuel or water), this diversity disappears. But normally there will be some diversity. If hydro is involved, the watersheds may have different characteristics so not all are short at the same time. If all use coal, different suppliers may be involved. Thus the supply should be adequate as a group except in the case of a nationwide strike. Even there, the group will be better off than each utility separately. The saving in fuel by using the most efficient units will permit the coal supply to generate more kwh. Oil available to one or more of the group can be used to make the coal last.

C. Reduce Installed Generation Costs

There are two major advantages to interconnection on the planning (i.e., investment) side of the picture. These are well documented in the technical literature. (See References 1, 2, and 3.)

First, as system size increases the reliability increases if the same size and type of units are used. In general this results because more units must fail concurrently to reduce the capacity to less than the load.

The normal result of this is that plans are made to reduce the amount of generating capacity installed to achieve similar reliability. Thus the reliability might not actually increase with interconnection as was stated in the previous section. However, the savings in capital requirements are as real a saving as the operating savings mentioned earlier.

A second factor enters into the selection of generators as system size increases. It becomes feasible to take advantage of scale economies of larger size units without excessive risk. There is usually an increase in the total installed capacity requirements for a given reliability as unit sizes increase. But since the larger size units are less expensive per kilowatt capacity, and may have a lower heat rate, the total cost of development with the larger units may well be lower than with smaller units. Very careful studies are required for each combination of systems to insure that the lowest overall costs are obtained. These costs must be combined capital and operating costs over a time period approaching the estimated life of the generating units being considered.

It is also quite possible that the costs of transmission lines and substations will be decreased if the actual tie lines required to affect a regional interconnection are relatively short and lines required by the individual companies can be used by more than the owning company to postpone another line. Occasionally the overall cost of transmission will be increased as regional interconnections are formed. In this case it is necessary to insure the savings in other areas

will pay the increased transmission charges. Again, each separate group of systems requires careful study.

D. Improved Relationships Between Utilities

Frequently, utilities that are adjacent do not have the same philosophies of development and operation. They may also be of greatly different sizes or of different types of ownership. In these cases historical dealings may have been minor or non-existent. Relationships may even have been hostile.

Even in these situations the savings described above can be made if the companies can reach an agreement that will lead to mutual benefits through cooperation and coordination after careful study and implementation. Before such studies and voluntary agreements can be made, there undoubtedly must be some reduction in the frictions that have been evident and which may have prevented coordination already. The economic motive is a very powerful one so that an effort to show the persons involved the amounts of savings that are available may well be successful.

E. Location of Facilities

Frequently utilities find advantages in pooling-type agreements in the ability to locate facilities outside their service territories. If there are not suitable plant locations inside the territory, it is necessary to go outside. Without regional pool arrangements it may be much more difficult to get the approvals needed to use extra-territorial locations. The advantages of joint development of sites by more than one utility are well known and include:

- o Delay of site development cost at other sites
- o Larger units at a time - lower cost per kilowatt
- o Joint ownership shares cost now
- o Spread of risk while unit is out of service

Less cost-oriented benefits are also derived. The need to develop fewer sites immediately results in fewer disagreements over environmental matters from the agencies charged with approval of sites. Part of this reduction in friction results because better sites can be selected by the utility whose territory is restricted or already built up with other facilities of some sort. Manhattan is a prime example of such a territory. The Consolidated Edison Company must go outside its chartered territory to find space for new generating plants.

F. Fear of Regulation

Some utilities enter into pooling agreements only when they recognize that if they do not, they will be forced into it by state or federal agencies on terms which may not be under their control. To avoid the disadvantages that adhere to being forced into an agreement, they take the initial steps. Several years may be consumed in preparation of a final agreement, however.

TYPES OF ARRANGEMENTS

A. Fully Integrated Pool

There are a number of groups that coordinate their operation as if they were one company and then split up the benefits according to an agreed formula. Such groups typically have an overall energy control center and additional control centers in each operating company. Some of these groups also coordinate the planning of their bulk power supply facilities, not as one company, but with considerable care and detailed study as a group. This is in addition to the studies each company makes of its own problems. It is the groups that satisfy both the operating and planning coordination that are classed as "fully coordinated" in this document.

Such groups have not sprung into being overnight in the past. It has taken many years of working together to attain this degree of coordination. Most started off as neighbors willing to interchange small amounts of power from time to time as the occasion seemed auspicious. As time went on it became advantageous to do more and more exchanging of power and energy. The dickering over prices became burdensome, so rules were devised that shared the benefits in proportion to the contribution to saving.

In any agreement for pooling, it is necessary for long time acceptability that the terms are believed by all the parties to be equitable. That is generally accepted as meaning that the companies that gain the benefits share the savings with the companies that allow them to be made. If one company always gives or always receives the benefits, the agreement will disintegrate.

B. Holding Companies

For companies that are controlled by a single holding company the problems are greatly simplified if the holding company has a strong controlling staff in the planning and operating functions of the system. Most of the problems of settling disagreements are simplified because of the ownership of the operating subsidiaries by the holding company. Strong leaders in the operating companies can and will stir up conflict if they disagree with decisions that they think affect their company's position adversely. But in most cases the control established by the holding company can prevail.

Holding companies can and do join other companies in pools. The agreements must be careful to state who has the votes for the holding company. Other than these items the problems for holding companies are the same as for separate companies.

C. Arms Length Bargaining

Many companies work together in "pools" where there is much less formality of agreement. (In fact, frequently the only agreement needed is a letter of introduction for the dispatchers.) Here the normal coordination is in the form of energy interchange on a spot basis. If one company has surplus energy, it will try to find a customer for it at the best possible price.

There are many such arrangements in the United States. It is also quite common between adjacent pools where one or the other has surplus energy or capacity or both.

In such arrangements the normal practice is to strike a new bargain each hour although longer periods of time are used. The terms are dependent on the bargaining ability of the participants. But there is no long range benefit to the plan to make it grow in value. The entire savings are limited to what can be bargained at that time. None of the planning and investment benefits can be obtained. The savings from coordination of maintenance outage and reduction of spinning reserve are haphazard or non-existent.

In arms length dealings there is practically no coordination of planning. The companies may exchange information about what they plan to do for some few years into the future. But there may be no formal methods to insure the information is current as plans change. This sometimes happens within pools having operating agreements also. It requires a coordinated planning effort to make the greatest savings from the pooling operation.

FACTORS PREVENTING COOPERATION

A. Definition of Formula for Sharing Economies

One of the major barriers to the completion of an agreement is the inability to agree on a formula for sharing the benefits. Each company management has responsibilities to its customers and owners to get the best possible terms so as to minimize the company's revenue requirements. A coordinated pool agreement is a complex document and cannot be put together hurriedly. But every day of delay is another day when the primary savings available from generation on the most economical plants are not obtained. While the managers worry about the allocation of a few dollars of additional savings, thousands of dollars of primary savings may be wasted.

One way to place an agreement in service quickly is to agree on the simpler items first and get the operation started. For instance, the concept of split savings on energy generation costs is simple. The application takes more effort to determine the true costs of generation to be shared. But it is a relatively straightforward process that can be implemented to get a start on coordinated operation. It also is the single factor with the greatest potential savings.

Any agreement must have a provision to make changes in terms as new concepts develop. By starting with this provision and one for sharing of energy cost savings, the cooperative operation can be underway with large savings being made and shared while other factors are explored and added to the agreement as they are accepted. Thus several years could be used in preparing an agreement while the major savings are achieved. It is a classic case of enlightened self-interest.

B. Mutual Distrust

As with all businesses there may be a belief on the part of the management that all their competitors are intent on stealing their market or otherwise increasing their share of whatever income is available. Whether it is true or not, is not important. The fact is that the belief exists, even among long associates in a successfully operating coordinated pool.

C. Institutional Problems

The institutional problems meant here are not those mentioned in the preceding section - that of mutual distrust and its ramifications. Rather the concern here is those of a deeper nature set in fundamental differences in economic and organizational philosophies.

A prime example is the long standing dispute between private and public ownership of power systems. This dispute is usually rooted in the attempt to protect a territory, but a deeper conflict may also be involved. Many managers of investor owned utilities believe that the government has no place in a business that the private sector can provide. On the other hand, officials of public power agencies may believe that it is in the best interests of the public to have a government owned and operated system. It is not the purpose of this report to cover that field. But this argument is a real factor inhibiting cooperation between utilities of the private and public supported types.

Another institutional factor that may act against formation of a pool is a large disparity in relative size of the companies involved. It is apparent that the joining of a large company and a small company will benefit the small more noticeably than the large. The large system has many kilowatts of reserve capacity available to benefit the smaller. The smaller has so few that the larger cannot see any noticeable difference in its own requirements. It is the same with the energy cost. The economies produced by the small may be insignificant to the large company. The incentive to pool is one sided here and it cannot be expected to be formed unless the contract is written in a manner to allocate the savings to make it worthwhile for both.

Where potential pools would operate in more than one state, there will be more than one state regulatory commission involved in setting rate and more than one environmental commission controlling facility siting. If one of the states has policies that result in a utility being unable to complete its share of the pooled facilities, it is a poor risk for other utilities to join with it. This may well work against formation of new pools.

Some legal constraints are imposed by problems concerning utilities that have no generating capacity but purchase all their power requirements. These involve: (1) anti trust suits concerning pool membership, (2) renewal of firm sale contracts in times of capacity shortages, (3) charter constraints on large municipal utilities. (Further details are given in Reference 4.)

D. Independence

When companies join pools they must give up some of their control over their actions. They are constrained to make their machines and lines available to others for the interchange of economy energy. Usually this results in the pool office, in one way or another, telling each company how much to generate on each plant. The owner no longer has complete control. There may be restrictions placed on the time at which units can be removed from service for maintenance. A winter peaking company in a summer peaking pool may not be allowed to maintain its units during its summer valley load period. Thus they may have to buy during their own peak period to do maintenance on units that would normally run then. These problems are complex and require careful planning and scheduling. People must accept the apparent interference and temporary reduction in income and balance it against the savings at other times of the year and the net gain in income measured over the entire year.

A further disadvantage of pools is the necessity of forming committees to carry out the coordination work and to settle disagreements. Considerable time of experienced and capable men must be devoted to the routine operations of the pool. Basic operating principles must be established and monitored. Tests of conformance to standards must be made. Changes in concepts must be discussed and differences reconciled. None of this is easy.

The problems of the pool must be considered in the plans of each of the member companies. None has complete freedom to plan its generation program without consulting the other members to determine their plans. Failure to observe this simple feature may result in feast and famine generation development programs. If every company decides to put a new unit in service in the same year, there may well be more capacity than needed. On the other hand if each decided to postpone planned capacity one or two years because others seem to have plenty, there may be an unexpected shortage. Thus there is a simple restraint on ac-

tion that was not present before. Actually the restraint offers a way to make further savings in cost if properly utilized. As mentioned in an earlier chapter, generating capacity can be coordinated at great savings if proper care is taken and careful studies are made. The problem of dividing the benefits is more complex but possible.

E. Fuel Resources

Most prudent utilities have a source of fuel under long term contract. Many have mines of their own for coal or lignite. Some have gas wells and transmission pipelines. Where these sources are restricted in the total amount of fuel that will be delivered over the years, the utility may be understandably reluctant to sell energy from that source. The present worth of the future replacement cost may be higher than the current price they would receive. There is little incentive to sell in such a case. These special conditions place an impediment in the way of coordinated operation. If fuel supplies become scarcer and more expensive in the future, this factor could become a serious deterrent to the voluntary formation of more pools.

Recently there has been a spate of state actions to control the export of energy from the state. Usually this takes the form of a tax on tons of material or BTU. The usual argument is that the state in which the resources are found objects to the dislocation of its land for a temporary economic benefit. If the state is to be torn up or denuded of its natural resources, a larger return is required now. Again this acts as a drag on the formation of pool operations since the fuel supply is so uncertain that no company is going to sell its resources to another.

IV. ATTAINMENT OF REGIONAL PLANNING OBJECTIVES

The attainment of complete coordination of planning to meet regional objectives will not be an easy task. As pointed out earlier the normal restrictions on system developments are due to small local obstacles such as an impossible right-of-way. At some time in the planning process these restrictions must be factored into the solutions. With the normal practice the local utility does its own planning and then coordinates the results with its neighbors, making changes as necessary to insure a proper fit of facilities planned to be added.

It would be possible to change the approach by starting with a group doing an overall generation and transmission development planning study. The group should include members from the companies involved who would contribute information needed for the planning. After a few acceptable plans have been defined, it would be necessary for each individual utility to study the effects of the overall plans on its internal systems which had not been represented in detail on the original

study. This process might reveal spots that required changes of the overall development either from a cost or feasibility standpoint. Thus the process would still be an iterative one requiring an overall plan, a review (this time by the individual utilities), and changes by the group. Only the order of the process is changed. The chief difference would be that the plans might meet the overall regional requirements more closely than via the individual-first route.

A more rewarding path might be to encourage more regions to form operating pools and ultimately to expand to fully coordinated pools with planning included. There are many areas in the country where pooling is practiced only at a rudimentary level. Studies should be made of these areas to determine how much savings could be made if fully coordinated operations were used regularly. Such studies, to be meaningful and acceptable, would have to involve the individual companies themselves and be done on a case by case basis. A generalized study would not be effective because there are too many differences between areas. Sponsorship could be by the state utility commissions or the DOE as appropriate.

Even this process would not result in immediate expansion of the ability of the groups to do regional planning. Initial steps in pool organization are normally oriented toward attainment of operating savings. These are immediate and measurable and significant. Benefits from coordinated planning are farther in the future and require considerable study of specific alternatives to show potential savings. Planning requires that the utilities be organized to work together in an orderly and efficient manner. Thus early efforts would be concentrated on obtaining the operating coordination. The other would grow with time and continued economic pressure.

With regard to the criteria themselves there are some points that need additional work by the councils. It seems reasonable that the councils should spell out the normal standards by which they design the system. That is, they should define the definite single and combined contingencies which the systems will survive without loss of load and with acceptable voltages, etc.

The criteria should be more carefully worded in conjunction with each other. There are numerous examples quoted where the criteria are different for the councils but the practices are probably the same. The differences are covered in additional rules or the criteria are not detailed to the same degree. They should be in the published criteria.

References to objectives that are undeniably desirable should be made more concrete. Phrases such as "balanced relationships," "excessive concentrations," "unduly complicated," or "excessive risk" all need definition to be of value. As they are written they give absolutely no indication of what the design practice is and are of little practical value.

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INFORMATION TRANSFER AND DECISION PROCESSES IN LONG-TERM REGIONAL PLANNING

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A state-of-the-art survey of "information transfer and decision making processes in long-term regional power system planning" has been conducted under a subcontract from the Department of Energy. Reviewed were (1) the data handling and coordination practices at regional and national levels, and (2) the use of decision support tools at the utility level. The review is based on material in the literature, the responses from a questionnaire, and discussions with industry personnel.

The regional and retrieval data exchanges work generally well, but there is potential for improvement in regional data base organization, avoidance of duplicate data collection, and better sharing of available data.

Advanced decision making tools exist for the industry. They are only used within the individual utility, however, and are often quite simple. Possible improvements include interactive use, integration of different decision functions, use of formal empirical methods for tradeoff and risk quantification.

It is recommended that development activities in regional data management and regional decision support be considered. The design of a transmission outage data base is also proposed.

INTRODUCTION

This paper reports on a subcontract under a contract from the Department of Energy (formerly ERDA) to the University of Oklahoma on "Regional Power System Planning: A State-of-the-Art Assessment." It deals with the area of "Information Transfer and Decision Making Processes."

The master contract is part of a program at DOE to identify needed research in the area of regional systems planning and represents a continuation of earlier

reviews documented in [32]. The goals of the contract are: (1) to determine the state-of-the-art of different aspects of long-range, regional planning; (2) to assess to what extent this state-of-the-art has been adopted and what its limitations are; (3) to identify areas for fruitful research, if any.

By long-range regional planning we mean planning activities which are carried out in the feasibility study phase of a project (as opposed to detailed design activities on a fixed alternative) and which involve at least two utilities but generally affect a larger area.

Planning has, of course, an aspect of analysis and an aspect of decision making. From the point of view of planning as an analysis activity, almost all generation and high voltage transmission planning is regional, independent of where it is carried out, while from the point of view of decision making, which implies allocation of money, planning takes place almost exclusively at the level of the individual utility company. This dual aspect characterizes any discussion about regional planning. Thus, when we talk about regional planning without qualification, the meaning depends on the context, but we always subsume the individual company's right and responsibility to make final economic decisions.

On the technical side, it is clear that future power system planning will require greater emphasis on regional criteria. Many factors contribute to this trend:

1. Tighter interconnection between utilities and regions, both for reasons of economy and reliability.
2. Financing difficulties and financial risk minimization at the level of individual utilities. This leads to an increased interest in jointly-owned facilities and in methods by which to finance them.

3. Increased involvement of federal and state regulatory bodies in the planning process. Regulatory criteria often have a regional (or even national) aspect. Examples are the allocation of limited resources such as oil and gas, or the preservation of the environment.
4. The pressure to find expansion plans which are regionally optimal rather than locally optimal, the assumption being that a regional optimum is always at least as good as the collection of corresponding local optimum solutions.
5. The above factors all affect the character of systems planning, but the overriding single phenomenon which is responsible for a different planning outlook is the dramatic increase in uncertainty about future conditions. This includes uncertainty with regard to future demand, available fuels and technologies, cost of construction and operation, and the general regulatory environment.

As a result regional system planning has become more complex and increased interest in the area has developed. While most people deal with planning problems of regional character in the conventional framework, others have gone further and proposed changes to the structure of the regional planning process. Breyer [10] and Uri [85], for example, advocate stronger regulatory involvement of the Federal Energy Regulatory Commission (FERC), Masud [58] proposes a national planning organization.

In defining the scope of our review we have chosen to assume that all desirable changes will come about in an evolutionary way and, therefore, our comments are directed towards the existing structure. But we do make the perhaps unorthodox definition that regulatory agencies are participants in the planning process. Interactions between them and the utilities-whether they take place in a cooperative or adversary spirit-certainly contribute significantly to the specification of the planning space, i.e., which solutions are feasible and which are not.

The goal of this subcontract can be rephrased as a "review of regional data handling methods and decision support tools". Specifically we have carried out the following tasks:

1. Assembled a selected bibliography. Since very little material is

available on the precise subject matter, other relevant areas have been covered.

2. Established and evaluated data handling and transfer methods above the utility level.
3. Discussed the "decision" making structure in regional organizations. The quotes indicate that these decisions have largely the character of reviews and recommendations.
4. Described available decision support tools, although they are used at the utility level.
5. Discussed areas which might be suitable for research.
6. Documented our findings in this report.

Regional planning, as every phase of planning, relies on the availability of data. Section 2 surveys the regional data collection and maintenance efforts of the reliability councils, but also of some national organizations (EEL, NERC, FERC). A key element in these information systems is the data base, its content, organization, and use. This review emphasizes a comparison of different regional data bases. It can be observed that, as soon as a regional organization handles (or intends to handle) more than load flow data or additional data uses, there is a trend away from base case libraries to more flexible data base organizations.

Regional decision making can be defined to include any activity which contributes to the problem specification, the determination of the set of acceptable solutions, and the final selection. With this definition some of the "soft" decision making at the reliability council level and the interactions between state regulatory commissions and utilities are reviewed in Section 3. But the emphasis is on methods and tools to improve the decision making process as it now exists. We exclude the area of conventional application programs which are treated in other subcontracts and emphasize the less structured phases of planning. We discuss such "decision support systems" as corporate planning systems, interactive systems, and, as a specific formal tool, decision analysis.

Evaluation the present state-of-the-art

We come to the conclusion that generally the present data organizations and decision making structures serve the

and decision making structures serve the industry well. They reflect both the present needs and the generally advanced use of computers in industry. Nevertheless, certain areas should be looked at in trying to improve the efficiency of planning and to meet anticipated future needs. Specifically,

1. In the area of national data collection, issues of unnecessary duplication of data collection, of better use of existing data, of centralization vs. decentralization, should be reviewed.
2. On the regional level, one should ask what other noncontroversial data could logically be collected and maintained at a regional organization. Outage data for generation and transmission equipment might be a possibility.
3. The proper organization of a data base for planning data should be investigated (not necessarily restricted to the needs on the regional level) which satisfies requirements of reduced redundancy and of more flexible access or update.
4. The fact that planner and corporate executive ought to (and will) come closer together in the company decision hierarchy. This has implications about the use of corporate planning systems.
5. There is a need to be able to quantify tradeoffs and decision behavior under uncertainty. In spite of its academic reputation, decision analysis and specifically the methods to arrive at an explicit multi-attribute utility functions, could prove valuable in structuring, understanding, and documenting planning decisions.

A bibliography grouped by topical areas concludes the report. Appendix A reviews some elementary data base concepts and logical data base organizations. Appendix B describes in some detail the data base structures of two U.S. reliability councils and a large European utility.

2. Regional Information System

Most regional planning takes place within utilities, ad-hoc groups of utilities and, in some cases, power pools. Reliability councils and supraregional organizations have primarily a

coordination and data collection function.

Data transfer and data collection takes place in the hierarchical structure of utilities, pools, reliability councils and national organizations.

We concentrate on some of the data paths through this hierarchy and on the data collection at regional and higher levels.

Specifically, we discuss the following three items:

1. The results of a questionnaire which was sent out to all reliability councils and several pools and large companies.
2. A novel data base approach in one of the reliability councils.
3. Some of the supraregional data collection efforts.

The Questionnaire and Its Results

A questionnaire was sent out to all reliability councils, some power pools, and some companies of regional size including some foreign utilities. The purpose was to obtain information on their organizations, the flow of data, the regional data bases, and the decision making process within these organizations. The few comments relating to decision making will be contained in Section 3.

The response rate was higher than 50%. Some answers were quite detailed, others were very brief. The responses discussed below represent a summary of the returns from six reliability councils, four U.S. and two foreign regional pools or companies.

The first question related to the organizational structure of regional planning, the data flow between different planning entities and other interacting agencies. The typical structure of data flow is shown in Fig. 1. The solid lines describe the normal reporting hierarchy. Dashed lines indicate some of the many alternate organizations and their interactions. They usually have the character of study groups, set up permanently or just for the purpose of a specific project, but which do not maintain their own data bases. They either rely on data bases in the normal pools or reliability councils, or on an ad-hoc study data base established for the purpose of a nonrecurrent project. Examples abound especially in the eastern U.S. where a typical company may maintain study ties to several surrounding pools and companies. Another example of a higher level study group exists in the

South Eastern Reliability Council (SERC) where TVA, Southern Company and the VACAR group (Virginia-Carolina) form the VST study group. It basically carries out the regional studies corresponding to SERC (excluding Florida which does not significantly affect the rest of the system).

U: Utility P: Pool RC: Rel. Council
UC: Utility Commission

Figure 1

In Fig. 1, one can distinguish five different data paths:

1. Utility-(Pool)-Reliability Council NERC: This involves primarily load flow data and in many cases, up to the level of reliability council also stability data. Utilities may report directly to the reliability council or through a regional data coordinator. A good part of the data is submitted in machine readable form (cards or tapes) although reports are still frequently used at the lowest levels. Of all the data paths, one has the most significant activity in the opposite direction, corresponding to (a) results of higher level studies being sent to utilities for review (usually on microfiche or in reports), and (b) data describing equivalenced networks which include the neighboring systems of the utility requesting the data.

2. Utility-(Pool)-Reliability Council) EEI: Besides certain operational statistics, this includes generator reliability data which is of primary importance here. See Section 2.4.1.
3. Subregion-Reliability Council-FERC: This data is submitted by the reliability councils on a voluntary basis to the FERC based on order 383/4, docket R-362, Appendix A-1. It basically contains data which should allow the assessment of the reliability of future operations in the council areas. It is discussed in Section 2.4.3.
4. Utility-FERC (now Energy Information Administration in DOE): This includes a large amount of data of financial and operating nature which is submitted at different intervals. See Section 2.4.2.
5. Utility-State Commissions: This data is similar to, but usually a subset of, the reported in (4).

The data of path 1 is maintained in data bases at different levels. Specifically, there are the council regional data bases and as an ongoing effort the 7-council data base at NERC. These regional data bases were the subject of the next questions.

Table 1 summarizes the meaningful responses. The data is arranged by reliability councils (RC), companies (C), or sometimes by a combination thereof (RC/C). "C" can be a regional holding company, a nationalized foreign company, or simply a single company within a reliability council. The columns of the table describe the following information:

1. The application using the data base (LF = load flow, S = stability, R = reliability, ... = others).
2. Characteristics of the regional data base (RDB):
 - a. Organization: In the case of base case libraries, the number of summer (S) and winter (W) base cases is given. A "DB" indicates that the data is organized in a way which does not reflect load flow usage and is nonredundant. The NPCC data base discussed below is an example of such an organization.

- b. Storage. In all cases the data is kept on disk (D) or tape (T).
- c. Updating is carried out annually (A) or semi-annually (SA). In one case only half the data is updated each year (1/2).
- d. Validation in all cases is basically left to the utilities (U) only two councils report use of the computer for validation (U/C).
- e. Load flow format is listed where applicable. In some cases external exchange (e) format is different.
- f. There is no special provision to strengthen data security anywhere except in the cases with a data base (DB) organization.
- g. Remote access exists at one

council and three regional companies. Elsewhere the desirability of remote access was judged very differently ("desirable", "nonsense").

The only suggested additions to the data base were for reliability data (R).

3. The data base one level below the organization questioned is called the local data base (LDB). The table indicates:

- a. How the LDB and RDB compare. In all except one of the reported cases, there is more detail available at the LDB level.
- b. How much time it takes for data requests from the other data base to be satisfied.

4. Any other desirable changes.

	Appl.	RDB								LDB		Desirables
		Org. Storage Update Val.				LF Format	Security Remote Add. Access Data			Date	Time	
RC ₁	LF/S	10S 10W	D	A 1/2	U	WCC	No	No	-	more detail	-	-
RC ₂ /C	LF/(S)	DB	D/T	SA, A	U/C	e:WEST/ IEEE	Yes	Yes	R	-	hours-day	studies by regional commission
RC ₃	LF(NERC) LF/S	5S 5W	D	A	U/C	PE e:IEEE	No	No	-	-	4 hours 1 day	-
RC ₄ /C	LF	10S 10W	D/T	A	U	PE	No	No	-	-	-	-
RC ₅	LF/S/ R/...	-	D/T/C	A	U	PE	No	-	-	more detail	2 days	remote access, (maybe) DB
RC ₆ /C	LF(NERC)	-	-	-	-	IEEE	-	-	-	more detail	-	less reporting to FERC
C ₁	LF	10S 10W DB	D/T	A	U	PE	No	Yes	R	same	instant	computerized data management
C ₂ , C ₃	LF/S/ ...	DB	D/T	A	-	-	Yes	Yes	-	-	-	-

TABLE 1

Even with this relatively small sample a strong correlation can be detected between the degree of planning which goes on at an organization and the existing or desired level of computer support for data handling: If an organization is only involved in the

collection and coordination of data, it has much less a need for a complex data base structure, remote access, and other advanced methods and tools.

Two aspects of the RDB and its relation to the LDB deserve additional attention: data exchange and data base organization.

In data exchange in a hierarchical information system as described here, the question arises how the data should be maintained in more than one place and who should be responsible for updating the several existing copies. Three observations are made:

1. The basic responsibility for maintaining the data resides with the organization where the data originates. See item 2(d) and Barthold [5] where it is argued that the originator of data is usually also the most frequent user. He should therefore not have to depend on a higher level central data base for maintenance, especially in view of possible communication problems. Similar sentiments in a general context are voiced in [1]. In addition, at the higher level the degree of detail is usually reduced (see 3(a)) and other aspects of data representation change; hence that data should be considered a distinct set. If updates originating at the lower levels are collected in a coordinated way, each higher level operation can update its own data representation in a consistent way and made available its modification to the next higher level. Thus, each level of the data hierarchy relies on lower levels for updates, but can maintain local consistency.
2. As a general principle, data should be exchanged in computerized form whenever possible. If hardcopy data is needed for other reasons, the data recipient should have the option of obtaining the data also in computerized form. It seems that this would significantly improve data transfer from the RDB to the LDB and conversely.
3. Standard formats for data transfers are very desirable and have in most places been implemented, at least for load flow data (see 2(e)). An exchange standard for stability data also exists in some reliability councils and IEEE will soon have a recommended standard.

For data representation within an organization, however, adherence to a external standard is neither required nor necessarily desirable. As can be seen from the questionnaire, different organizations use different formats, usually for good reasons (e.g., different application programs with different features). The only requirement for each organization should be that there exists a well defined, computer-executable

transformation from the internal format to the exchange format and back.

The data base organization of regional data base has to be evaluated in terms of the functions it is intended to serve. The main functions of the normal reliability council data base are:

1. To provide a repository of data which describes the system of the council and its neighbors for the next five to ten years.
2. To provide the capability of extracting, and in some cases, of equivalencing, subsets of this data for specific studies.
3. To exercise some control over the data. This includes review and validation of data values, coordination of the updating procedure, setting and enforcement of format standards and other measures which ensure good data quality.

These functions are served well by the conventional data base of a collection of load flow base cases. Data availability, data quality, and some degree of data control is achieved. There are a number of drawbacks in this data organization, however: (1) Updating can be very cumbersome; (2) there exists unnecessary data redundancy; (3) there is a lack of flexibility in how the data can be used. We elaborate on these points in discussing the NPCC data base.

These three shortcomings are typical of application oriented data bases and can be largely eliminated by a data organization which attempts to control redundancy and provides a degree of data independence.

The concept of controlled redundancy implies that data elements should be stored only once, unless there are strong economic or technical reasons to do otherwise.

Data independence implies that the data base organization and applications are to be treated separately. It allows reorganization and expansion of the data base without affection existing applications. Conversely, new applications with needs for some of the existing data can be accommodated.

Appendix A reviews these two and other objectives of data base design in somewhat more detail. Here it suffices to point out that many data base systems eliminate unnecessary redundancy and provide for the use of data by several

applications without the user having to be aware of the "detailed data representation."

A simple approval to data independence is to separate the application from the data base through an intermediate study data base. The study data is extracted from the main data base and is formatted to suit the application. Thus, the desired separation is achieved.

Whether a base case library or a different data base organization should be chosen for the reliability council data base is simply a question of the intended use of the data. It is evident from the questionnaire that all organizations which do more than the traditional maintenance of load flow data, either have a different data base organization, or are considering or implementing one. Hence, if reliability councils were to become more active in the planning process, such alternate data base organizations should seriously be considered.

Basically the same comments apply to the NERC data base developed by NERC's Multiregional Modeling Group. Its organization is also that of a base case library with cases for the even numbered years ten years into the future.

We describe below the situation at the Northeast Power Coordinating Council (NPCC), at Electricite de France (EDF), and, to a lesser extent, at the Central Electricity Generating Board (CEGB), as examples of the data handling methods in a progressive planning organization. In particular, we want to emphasize the respective data base organizations which are fundamentally different from the base case libraries of most councils.

2.2 The Data Base at NPCC

The NPCC consists of four areas, the New York Power Pool, the New England Power Pool, Ontario Hydro and the New Brunswick Electric Power Commission who are individually responsible for their planning and operations. Besides maintaining a regional data base for its members (which is of primary interest here), NPCC (1) collects and compiles the data requested by the FERC under FPC Order 383-4, Docket R-362, Appendix A1. This collection activity is the same as for all other reliability councils and will be discussed separately. (2) has started to look at establishing a transmission outage data base to be used in reliability studies.

Most of this material is based on [67] and private communications.

Emphasized are main design aspects, technical details are listed in Appendix B.

NPCC's data base is designed by Westinghouse and is nearly operational. It contains data relating to NPCC's generation and transmission facilities presently used in the context of load flow studies. The main purpose is to provide a data repository for all member companies and to provide the functions of storing, accessing, extracting and maintaining this data.

The data basically consists of load flow data for a 20-year time frame. Six different load conditions are stored for the first six years. Two conditions (summer and winter peak) for the next fourteen years. The significant aspect, however, is that the data is not stored in load flow files, but in ten separate files which do not reflect any specific anticipated use. The following files exist: (1) buses; (2) bus load; (3) thermal (or variable output) generators; (4) hydro (or fixed output) generators; (5) hydro stations; (6) transmission lines; (7) transformers; (8) shunt devices, fixed data; (9) shunt devices, load-dependent admittance data; (10) areas.

The system accommodates 7,500 buses, 12,000 lines, 3,000 transformers, 3,000 fixed and 2,000 variable output generators, 7,500 shunt devices, and 100 areas.

Files 2,5,9, and 10 contain time varying data (load specification, generator levels, shunt admittance values, spinning reserve). The other files contain essentially static or slowly varying data. The time dependence of equipment availability is represented by an in service date and a retirement data.

The files are on direct access devices. Retrieval takes several possible forms:

- Listings of any of the ten files and combinations thereof.
- Retrieval from any file based on year.
- Retrieval of data associated with a set of buses. First, the buses of interest are selected. This can be done according to year, voltage, priority rating, and others. Then, all files are searched for elements connected to the buses of interest. This retrieval is quite time consuming.

- Retrieval for load flow studies. Specification of the season and/or a load level determines the selection. The result is put into a study file. Then a generation scheduling program determines generator outputs to balance the load. A system-wide load flow is run to obtain bus voltage information, before a network reduction is applied. Buses are retained based on a priority rating. Output can be in COMMON format or Westinghouse format.
- Retrieval can be carried out locally or via remote terminal.
- Small updates can be entered in change specifications in card format.

Major updates take place every six months. On a yearly cycle, retired equipment is deleted and new equipment added and four new load cases are added for the sixth year. The files are then recompact.

The update procedure is coordinated in the four areas; the details checked by an area coordinator, and collected by a NPCC data controller who carries out the actual update. It is instructive to compare advantages and disadvantages of the described data base organization:

Advantages:

1. Elimination of data redundancy. Each element is stored only once, saving storage space and making updating simple and consistency automatic. This is in contrast to the case library approach where a change, say, in a line specification, may require an update in all the files in which the modified line is in service. Updates of multiple copies of a data element are always potential sources of inconsistency.
2. Separation of static and dynamic data. This is useful because the two classes have different update patterns. It also provides the flexibility to add other load cases at will (light load case; special VAR conditions), or modify other dynamic characteristics without impacting the static description.
3. Separation of the data from the application. This means that:
 - a. data can be added to existing files and, obviously, new files can be created without impacting

the existing uses.

- b. the existing data can be used for other applications. For example data can be extracted for a FEPC report, or for stability and short circuit studies.
4. Flexibility in case selection for load flows. Static data can be selected according to year and voltage level; different areas can be represented to different levels of detail; load profiles, shunt compensation, and generation scheduling can be modified with extreme flexibility.

Disadvantages:

1. The clear disadvantage is that retrieval of data across several files can be time consuming. For many applications such a search is unavoidable.
2. Transformation programs have to be written to bring the data from the data base form in the form in which it is to be used. An intermediate study data base is required. This is the "reverse side" of advantage (3).

Again, if the reliability councils restrict their data coordinating activity to assembling consistent regional and interregional load flow base cases, then the file approach is preferable. On the other hand,

- if more flexibility is desired as to how the data can be used,
- if improved and greatly reduced update activity is important,
- if future application are contemplated,

the NPCC approach shows great promise. Other examples of similar data base organizations exist. They are described in [50, 3, 61]. The IBM Power System Package [50] is no longer available, but it had a data base model which logically was very similar to the one described. It was designed to serve load flow, transient stability and short circuit studies.

The EDF data base is described by Auges [2]; details are also given in Appendix B. Although the logical data organization is different from that of NPCC, many of the design decisions are surprisingly similar:

1. A distinction is made between primary and derived data, semi-stable and dynamic data.
- . The semi-stable or permanent data is organized into seven independent files containing: line, transformer, steam and hydro generators, shunt compensation, consumers and international exchange data.
3. Separate files contain data on yearly generation and demand patterns for situations of interest. Thus, there is an extremely strong similarity in this logical organization.

Distinct from the NPCC approach, each file is subdivided into independently accessible subfiles containing topological, electrical, economic, or operational data. The reason for this further subdivision is that different data types usually have different sources, uses, update and retrieval frequencies, and are possible better treated individually. The EDF-authors use the concept of a "data circuit" which describes data flows, from the data entry point to its intended end use. This file structure then takes into account different identified data circuits.

Retrieval is possible: (a) in conversational form, to obtain individual records. This is aided by a hierarchically-indexed file, allowing up to three selection parameters (example: select (1) generators; (2) of 1987; and, (3) economic parameters only). (b) for a subsequent definition of a study base, similarly to NPCC.

Updates are carried out once a year, both for practical reasons and to present a stable data environment to long-term studies. However, a change file is being maintained to keep tract of recent changes.

The CEGB data base is discussed in part by Moore, Blair, and Keress [61, 8, 53]. Although not many details are available, some characteristics are the same:

- the data is split into stable and dynamic classes: transmission and generation data and demand data.
- time dependence enters via "starting data" and "closing date."
- the assembly of a load flow case proceeds from elementary files, even more basic than those at NPCC or EDF (example: load flow line data is computed from a transmission facilities data file).

One interesting item in the CEGB data base: A quality attribute is attached to the data where appropriate to indicate whether the data is estimated, measured, computed, etc..

2.3 Supraregional Data Collection

2.3.1 The EEI Equipment Availability Data Base:

EEI has been collecting generation facility outage data under a computerized system since 1966. Most American utilities contribute their data on a voluntary bases.

The purpose of this effort is to maintain a pool of generating equipment outage data to used by utilities, manufacturers, and other interested organizations. Data is submitted in four different ways:

- Outage reports including outage cause code, type, and duration as well as manhour statistics (quarterly).
- Outage summary reports (yearly).
- Unit design data (for each new or modified unit).
- Data on fossil units 600 MW and larger (quarterly).

In [27], detailed definitions and input format instructions are given. Punched card input is encouraged; tape input occurs occasionally, most input is on input data sheets which can be processed by optical scanning. Data validation is primarily the responsibility of the reporting organization, although there seems to be some computer error checking. An indication of the considerable effort involved in collecting and validating outage data for a pool, is given in the paper by Cucchi [19].

The EEI data base is maintained on tape; details of the data organization are not available. In [30], a description of the EEI data base implies that the data is ordered by system, unit, outage code, year, and card code. This permits easy retrieval of data selected according to any of these parameters. The same source mentions a size of the data base of 350,000 records.

Each year EEI produces a report on equipment availability over a ten-year (see [26]), it also provides each utility with specific information on its own data. Manufacturers receive data on their equipment. Special reports can be requested according to the mentioned selection parameters, as long as the

confidentiality of the data is preserved or the parties concerned give their approval.

A recent EPRI study of reliability data systems [30] indicates that the EEI data base gets higher use than any of the other complementary reliability data systems, but that at the same time a more comprehensive system is desired. The EEI system is good for comparing power plant availabilities and monitoring their time trends; it seems to be lacking in the description of the failure causes. Also, response time seems to be long, especially if utility clearance for sensitive data is required.

Reliability data bases as the EEI data base meet a major need. Not surprisingly, increased demands exist for more data and better and probably more flexible response. The EPRI report indicates that there is an industry-wide interest to consolidate the EEI data base with others, primarily those containing nuclear plant data, and apply a global classification scheme to all data available. A parallel ANSI report [1] comes to similar conclusions and stresses that a modified, centralized reliability data base is needed.

2.3.2 The Regulatory Information System (RIS) of the FERC:*

The data collection effort of the FERC which is supported by the RIS is another example of a national collection of electric utility data. Although the data is primarily financial and operational, some of it is relevant in the context of system planning, at least in the sense of defining the future status of utilities. Basically, the RIS serves the purpose of

1. providing information to the FERC in its regulatory decision making process
2. distributing information in processed form to interested parties, in particular Congress and the general public.

The FERC (then FPC) recognized around 1973 that its data activities had to be totally restructured to satisfy its future needs. As a result a new data management system, RIS, was designed and is being implemented. This system addresses all

phases of data handling: data collection (new forms, new procedures), validation, data base management (vendor supplied system: SYSTEM 2000), and distribution (standard reports, special reports). The principle content of the RIS data base consists of the data periodically submitted by electric and gas utilities in accordance with FERC regulations. This includes data from (see [34]):

1. Form 1 (and variants 1-F, 1-M) containing detailed financial and operating information. It is submitted annually. Form 1 consists of more than 100 pages.
2. Form 3 and variants on retail power rates (annually).
3. Form 4 on generation of electricity and consumption of fuels (monthly).
4. Form 12 (and variants) on yearly generation, energy exchanges and delivery to consumers (annually).
5. Form 12-E-2: Monthly supplement 12 for large utilities.
6. Form 12-F: Power line data for lines 69 kV and above. Form 12 also contains information on generation equipment every five years.

At this point, the information submitted to the FERC by the reliability councils is not part of RIS.

All these forms are presently in the process of being replaced by new forms. They no longer have the character of reports but are designed for data processing, including optical character reading. At the same time, redundancies in the old reporting forms will be eliminated. Some selected respondents will submit their data on magnetic tape. This aspect seems to have the character of an experiment, but clearly makes sense for those utilities who maintain the required data already in machine-readable form.

The RIS contains six independent data bases on:

1. corporate and financial data
2. electric operating data
3. gas operating data
4. environmental data

*This effort is now under the Energy Information Division of DOE. For simplicity we refer to it as a FERC project.

5. legal data
6. internal administrative data.

Data bases (1), (2), and (4) are relevant for electric system planning, in that they affect the regulatory process.

The data bases are under control of a data base management system, SYSTEM 2000. A summary of its features is contained in [20]. The data base organization is hierarchical; access to the data is provided through multiple indices (see Appendix A for terminology). The implementation uses indexed and sequential files. Other important features include on-line or batch querying, report writing, access control, recovery, and availability of a data dictionary. In view of FERC's intention to make the RIS system software available to other users, the fact the SYSTEM 2000 can run under many common operating systems is important.

The data of the RIS data base incorporated many of the characteristics which made the use of a data base system desirable. There was a large amount of data with a great deal of redundancy to be eliminated (20); there was a need to have all data accessible in one place, to implement validation procedures, a report writing and a querying capability. There was also a desire to operate in a more efficient and timelier fashion.

The FERC believes that the RIS:

1. increases the effectiveness of decision making due to faster, simplified access to data and resulting capability to test the impact of decisions prior to issuing orders.
2. decreases the cost of collecting, processing and utilizing the data. This is primarily due to records consolidation and centralization, reduced clerical processing, and the use of reporting on exception basis.
3. improves FERC's regulatory activity as well as its interaction with state utility commissions, utilities and the public. This is primarily due to the timelier availability of data and the increased productivity of the staff.

A significant aspect of FERC's future plans is to establish closer coordination with state utility commissions. Much of the data which utilities have to submit to FERC is also submitted to state commissions, often in the same form. Utility commissions could obviously profit

from an arrangement where they either could access or duplicate the RIS data base. This would bring benefits such as improved data collection, uniform data bases, validated and standardized data. Just as importantly, the utilities could then be relieved of part of their reporting burden.

In principle, this seems the right way to go if the needs of state commissions and FERC can be coordinated. A state with light processing requirements would probably use the FERC system with remote access. Larger states with active regulatory commissions might prefer to have their own data base management system and obtain data base updates from FERC on a regular basis.

In addition, since the system provides the mechanism of access control, there is no fundamental reason why utilities might not be allowed to access the nonproprietary parts of the data base. This would provide the utilities with an additional source of up-to-date information, and would obviate the need for much of the hard copy reports issued by FERC. Technically, it is possible and from a national point of view such a data handling consolidation makes sense. Whether the institutional barriers are too great in comparison to the expected benefits, however, is difficult to estimate. Another data collection effort by the FERC concerns the data submitted annually by the reliability councils. The next section describes this effort in more detail.

2.3.3 Annual Reports by the Regional Reliability Councils to FERC:

Under the FPC Order 383-4, Docket R-362, Appendix A-1, the reliability councils provide annual reports to the FERC detailing their bulk power supply plans. The reports are compiled by the reliability councils (although in some cases they represent simply a collation of subregional reports) and contain the following information:

1. Estimated summer and winter peak demand and energy for the next ten years. The first two years are given a month-by-month basis.
2. Existing and future generating capability and scheduled capacity exchanges for the next ten years.
3. Estimated capability, demand, and resulting margin for the next ten years. Assessment of the adequacy of the margin for the next five years.

4. Environmental controls for steam generation (no longer required).
5. Transmission network description by maps and by a list of planned additions for the next five to ten years.
6. Description of the load flow and transient stability studies carried by the council, its members, and intercouncil groups.
7. Description of the primary communication facilities.
8. Evaluation of impact of delays and changes in transmission plans.
9. Description of the coordinated regional (operational) practices.
10. Load and generation capability forecast for the eleven to twenty year period.
11. Transmission network configurations for the eleven to twenty year period. Presently, all this information is submitted to the FERC in report format, i.e., in an overall unformatted document. A clearly identifiable subset of the data lends itself very well to standardization and formatting, however, and FERC/NERC have, in fact, defined content and format for items (1), (2), (3), and (10). It seems that tabular parts of items (5) and (8) could also be standardized. There could be several advantages of maintaining and submitting this data in machine-readable form:
12. Some of the data (e.g., items (2), (5), and (10)), may not change much and could be updated rather than recompiled.
13. Part of item (3) can be deduced from (1) and (2) and is therefore redundant. Similarly, (8) is a subset of (5) and contains mostly redundant data. While for the purposes of a report, this duplication of data makes sense, it would not be necessary (nor desirable) to maintain this redundancy in storage.
14. At the FERC, much of this data is collected for all nine councils, processed and published in report form every year (see e.g., [35], [36], and many others). While there is a lot of work going into interpreting and displaying the data, the numerical manipulations could be easily done by computer. To the

extent that they are already ready done by computer now, one could save the labor-intensive process of reentering hard copy data into the machine. Much of this data do already exist in computer-readable form at the utility and pool level at the time of collection as evidenced by some sections of the reports whose tables are computer printouts. For example, the generation and transmission system forecasts are implicitly contained, in part, in any ten-year base case library. Thus, in order to save manpower and avoid transcription errors, direct computer to tape to computer processing seems desirable. Some of the additional information provided in this document refers to standards and criteria. In a loose sense, these regional standards are part of regional planning decision making. They are therefore summarized in the next section.

2.4 Comments

This section has shown two things:

1. Based on the results of the questionnaire and on the more detailed review of two data base organizations, the dependence of the data base structure on the intended use has become obvious. We predict that more regional data bases, including some at reliability councils will enlarge their data handling activity and convert to a non-redundant type data base organization for multiple applications.
2. The three examples of supraregional data collection activities have covered a spectrum from the fairly simple to the very ambitious. Again they show how different objectives ask for solutions of different sophistication. However, in each case desirable improvements can be identified. As the demands on these systems increase, these desirables will become requirements and more advanced data handling systems will have to be developed as in the case of the RIS. Duplication of data collection exists both in the reliability area as well as in the FERC area.

3. Decision Making in Regional System Planning

3.1 Background

Much of the interest in a state-of-the-art survey of regional system

planning is due to the significant changes which have occurred in the power system planning environment. The most obvious are:

- The dramatic increase in cost of fuels, construction and capital.
- The new emphasis on preservation of the environment.
- The end to a guaranteed availability of all fuel types.
- The longer delays in the approval process for new facilities.
- The increase in general uncertainty about future trends, particularly with regard to demand, government policies, and the general public climate.

Because of these changes, system expansion planning has become significantly more complex and has to some degree changed its nature:

1. The traditional goal of providing reliable electric energy at minimal cost required finding the cheapest expansion alternative subject to a reliability constraint. Today more constraints have to be considered and some constraints are no longer inviolable: e.g., reliability considerations may now be represented as part of the minimization criterion and thus be subject to a genuine tradeoff against other goals. In general, the problem has to be formulated as a multi-variable optimization in which several conflicting objectives have to be reconciled.
2. The long-term expansion optimization is more difficult because future parameters are so much less predictable. This has three distinct effects:
 - a. The analysis is inherently less reliable. To compensate for this, more case studies have to be carried out.
 - b. The method of comparing long-term alternatives on a scalar basis, e.g., by present-worthing, increases the probability of misjudging the future. For example, an erroneous discount rate may not only distort the comparison between projects occurring at different times, it may also totally mask the importance of drastic future events.

c. The risk preferences of decision makers have to be taken into account explicitly.

3. The increasing role which federal and state regulator agencies and, by extension, the public play, has in fact made them participants in the planning process. This statement is not intended to be in conflict with the fact that the real decisions in long-range regional planning are still made by the executives of utilities. It simply points out that there are more aspects to planning than those final executive decisions which allocate the resources in dollars, manpower, and time to implement a plan. On the way to such a final decision, many other parties also are decision makers, by defining, structuring, constraining, and quantifying the decision space for the executive. From this point of view, certainly, regulatory agencies become planners as well.
4. Partially due to the greater uncertainty in demand forecasts and the higher construction costs, more joint ventures involving two or several utilities, are being implemented. This means that the process of arriving at a final decision has to deal with the reconciliation of conflicting interests. While in an individual company the hierarchical structure automatically takes care of this problem, there does not exist now a higher level decision maker who resolves the divergent interests of utilities by invoking a higher level criterion.

This last point raises the question whether in some cases the planning decision process should not be carried to regional levels above the individual company. The argument is that, in principle, the more global optimization should lead to decisions which are at least as good as the equivalent combination of individual utility decisions.

There is much to be said, however, for the opposing point of view as well. For one, the present system has evolved over the years and is generally in an excellent state, having relied on economic considerations to guide its decisions. Furthermore, it is common experience that highly centralized and coordinated systems become more vulnerable to disturbances and less flexible in their actions.

Here, we have no intention of judging the issue. We take the attitude that

whatever improvements might be attained, it is preferable to attain them in an evolutionary way. Hence, we accept the present system as it is and look for improvements to accomplish the process of regional planning. Specifically, we look at three questions:

1. To what extent does there exist regional planning at the level of the reliability council and could it be increased?
2. To what extent do regulatory agencies participate in the planning process and how could the present process be made more efficient?
3. In view of the increased complexity in planning, what new tools are being used?

In the sequel it is to be understood that the term "decision" may be used in the broad sense as implied above.

3.2 Regional Decision Making

It is clear that in the conventional sense of the word, reliability councils are not involved in planning. In fact, in the replies to the questionnaire all traditional councils were unanimous in this assessment: Planning and decision making takes place where the money is. However, if we admit the extended meaning of the term which includes all indirect action affecting the planning decision space, then they indeed do regional planning.

Reliability councils participate in at least three ways: They coordinate operational practices, review plans developed at lower levels, and they carry out their own regional studies. We review these points briefly:

1. Reliability councils vary in their degree of homogeneity from widely diverse (e.g., WSCC) to very compact (e.g., MAAC = PJM). Hence, the uniformity of standards varies accordingly. Since the councils' primary function is to ensure operational reliability, all their standards are basically operational. Some of them affect planning, however, because future systems have to be designed to satisfy those standards. They include (see item 9 of the reports from the councils to the FERC):

- load shedding programs
- relaying strategies and standards

- reserve policies but also a definition of
- reliability criteria
- stability criterions

The last two are different of course, in that they do not directly affect operations, but only the analysis and planning of future systems. There seem to be other possibilities of standardizing analysis assumptions for the purpose of making all studies in the region more compatible. Examples could include:

- Scalar parameters such as discount rate, inflation rate, regional load growth rate and other macroeconomic parameters.
- Case study definitions which could be regionally significant. This might be in terms of scenarios on load growth, fuel cost and availability, cost of capital, cost and availability of technologies, and other relevant parameters. By providing all members with the same case definitions, their studies would be consistent and more easily comparable.

2. They participate in the review of expansion projects initiated at the utility or the pool level which have regional impact, i.e., high voltage transmission and generation expansion plans. This is handled by the task forces of the planning and operating committees of the councils. See Fig. 2 for the typical three-level committee structure of a reliability council.

Figure 2. Committee Structure

Basically, the task forces of the two

coordinating committees receive information from member companies on any significant changes or additions to the system or to the proposed changes. The appropriate task force studies and evaluates these changes and reports its findings and makes recommendations.

Figure 3 also shows the lower level activities of the review process. Shown is a case where a pool is actively involved in planning and is distinct from the council. In other cases, the two organizations may almost coincide or the pool participation is weaker or nonexistent.

Figure 3. Review Process

Other councils may be organized slightly differently, especially if there are no pools or if the pool is identical to the reliability council. Note that some studies are initiated at the pool, although the ultimate decision will be with the member companies.

3. They study regional and interregional problems such as intertie expansions, generation mix distribution and site location, regional load growth projection and energy transfer capabilities. Many of these projects are documented in the councils' yearly report to the NERC [63] and in item 6 of their annual report to the FERC. Again, these studies do not lead to any direct decisions, but they contribute in defining, reducing and constraining the options available to the planners and decision makers of the member companies. These studies have the character of background studies and usually do not address a specific expansion project. Individual utilities will therefore frequently

carry out similar studies in a more detailed context allowing them to include tentative information and more details in the system representation.

3.3 The Regulatory Commissions and Regional Planning

Of the two types of regional regulation - the FERC and the state regulatory commission - the latter has a greater impact on the planning process. The FERC's direct influence on planning is presently only in the licensing of hydroelectric facilities and in the wholesale rate settings. State agencies generally regulate both the setting of rates and the construction of new equipment.

This section tries to demonstrate by way of an example to what extent a typical commission with a strong mandate participates in the planning process. The example is the California Energy (Resources Conservation and Development) Commission which is chartered to provide energy load forecasts, determine desirable generation mixes, and provide general planning guidelines. It also acts as a review agency for new system expansions. Specifically, it is in charge of the plant site approval process which consists of two phases. Utilities are required to file: (1) a notice of intent (NOI) and, if approved, (2) an application for certification (AFC). The review procedure for the AFC is not fully developed yet, but is intended to cover the engineering designs relating to a selected site.

In the first part (the NOI), at least three sites are submitted, two of which have to be approved for overall NOI approval. In reviewing the proposal, the commission has to consider the environmental, health and safety, economic, and land use impacts of a proposed construction site. More generally, it assesses the necessity of a proposal (in view of load forecasts and reliability considerations), the resulting generation mix, and the financial feasibility.

It relies on in-house staff and external consultants for expert opinion. As such, the commission engages in planning in a similar way as the company executive: It reviews proposals and opinions, it can request alternative studies on each aspect of the proposal, it evaluates the proposals by a set of criteria.

Usually the priorities among the criteria tend to be different, of course, for the commission and for the utility.

The commission will reflect the public mood and the view of the political forces in power. In rate hearings it will tend to favor the financial well-being of the consumer over that of the utility. However, regardless of the commissions' criteria, the process used to decide on the best expansion is basically very similar and has to rely on similar tools and information.

There is another major difference. The commission has the power and the need to request from the utility, studies and ad hoc information beyond that which is supplied under routine requirements (biannual load forecasts, financial statements, copies of FERC reports) and that which is part of the NOI. Usually, its staff and consultants do not have access to all the information nor the personnel to conduct all the studies. Unfortunately, this reporting and studying represents an additional burden on the utility which, in the case of a large utility may amount to additional costs of several million dollars.

The approval process is quite lengthy. In the case given, both NOI and AFC are scheduled to last for eighteen months.

In reviewing this example, one can arrive at some fairly obvious observations:

1. For the state commission to do its job well of engaging in general regional studies and carrying out the certification process, it needs tools and data similar to those used by the planners of a utility.
2. Much of the information required exists either in the data files of the utility or, quite often, in those of the FERC.
3. The review and certification process is basically very similar to an evaluation-of-alternatives procedure in a utility. The evaluation criterion is different, however.

Two desirable improvements can be specified:

1. There is a potential for better sharing of data. Any data which is public or which was derived from public data should be accessible without undue delay. A system as the one proposed by the FERC would go a long way towards that goal.
2. There is a potential to speed up the process more hypothetically, by

providing some system which facilitates the decision making and the reconciliation of differences. The next subsection discusses such systems.

3.4 New Decision Tools

The dramatic change in the electric utilities planning environment has focused the attention on three aspects of decision making:

1. The strong interrelatedness of different planning activities, and hence, decision making. This applies to planning within a utility, between utilities, but also between a utility and a regulatory agency.
2. The need to quantify many aspects of a planning which are inherently difficult to capture in numbers: Tradeoffs, preferences, risk behavior, and so forth.
3. The need to obtain some answers quickly, in spite of the long-range time frame of planning.

Many system concepts exist which address these points in varying degrees. Depending on the context and on the emphasis placed on different features such systems are called decision support systems, executive systems, corporate planning systems, or interactive systems.

The unifying feature seems to be that in each case there is a data base, an on-line access to it, and one or several applications which process data from the common data base. There is also a certain amount of general support available which allows the user some flexibility on how to use the data and the applications. Below we review some of the relevant work.

As a separate relevant item we discuss decision analysis (DA), which can make a contribution to point (2). DA is nothing but a tool to structure and quantify a decision space. Once the structure is determined and all aspects are quantified, mathematical analysis and optimization methods can be applied.

3.4.1 Corporate Planning Systems:

There is strong evidence that many utilities feel that their different planning functions should be more closely coordinated. This has led to increasing interest in corporate planning systems which address some of the identified needs:

1. Better communications are established between different planners and planning organizations.
2. Consistent data, assumptions, and standards are used across all related functions.
3. Duplication in analysis, data processing, and data storage is eliminated.
4. The efficiency and speed of planning is improved.

An ideal corporate planning system consists of a central planning data base, mathematical model of the corporation's major planning functions and a control program which allows the user to interact with the data base and the models. Figure 4 is a simplified version of a diagram in Neale [65]:

Figure 4. Corporate Planning System

In Neale's approach, all main corporate planning functions are emphasized equally. The data base serves as a data repository and a data interface between applications. This model is functionally similar to the one discussed by Naylor and Mansfield [64] in a survey of corporate planning systems, although they were assuming an unregulated, multiproduct-multidivision corporation.

It is estimated that 60 to 80 of the large utilities have a corporate planning system of one form or another. Most models are essentially financial models; load forecasting and system expansion are incorporated in the data input. Some models are extremely simple, providing as output only an earnings forecast per share, others are very complex.

Conversely, there exists many engineering planning models where the financial consequences are either not taken into account or else only in a rudimentary form. In order to arrive at a

satisfactory overall expansion plan, financial and engineering models have to be used iteratively until a global solution is found.

Thus, Neale's model is one step ahead of most implementations, by treating all functions equally and making them available jointly under one system. Several vendors' market such an integrated approach. Its advantages are clear:

1. Common data base, with better data control.
2. All functions equally accessible, immediate communication between functions.
3. Presumably faster arrival at an acceptable overall solution.

There exists some divergence of opinion to what extent such integration is desirable. The main objection is that an individual user usually has a high degree of expertise only in one functional area and will not feel comfortable using the other integrated functions. This is probably only true because this user is not used to think in terms of all functions, and hence this is more a result of the organizational structure of the company than of a limit in human mental capacity. This is an illustration of a phenomenon which often goes with the use of a new corporate system: In obvious and subtle ways the system will impact the existing organization. Specifically, this means planners will have to increase their professional horizon both horizontally into other functions, as well as vertically into higher levels of decision making.

Corporate planning systems are for mid-term to long-term problems. Financial analysis are meaningful for periods as short as 1 to 2 years, expansion plans lie in the 3-15 year time frame. The use of a corporate planning system is interactive only for data base interactions (i.e., data editing, input and output activities), and problem submission, problem execution takes place in the background.

Early contribution in the power systems area were made by A. Wood and coworkers [88, 89, 72, 74]. Troescher [83] has described a system in operation at RWE. The same decision environment is dealt with in the form of a corporate management training program, developed by the Bernese Utilities [55] and modified by RWE.

As a corporate planning model we look at the one by Sager [73]. It is used by

Northern States Power Company which includes two companies and six utilities in two states. It is basically a financial model and is used for cost flow analysis, the study of financing options and revenue requirements. It also provides a model for intercompany accounting and separate depreciation, tax and financing procedures for each company. It is used in expansion planning, rate filings, budgeting and other financial operations.

The other planning functions are represented by auxiliary models whose outputs feed as inputs into the financial model. The basic time unit is a month; the program can produce yearly financial reports with monthly figures, 1-2 year cash management figures, 5-10 year project evaluations, or 25-30 year studies on the financial aspects of long-term planning options.

There are separate data files for:

- plant-in-service, organized according to tax classifications
- plant retirement
- future plant construction
- nuclear and fossil fuel cost data, derived from auxiliary programs financial base case and change case data. The base case data represents the stable assumptions, the change data for a given study is used to modify the base data before execution of the programs. This preserves the integrity of the base data.

Comments:

1. In Sager [73], several practical aspects of a corporate planning model are pointed out:
 - a. models should initially be simple to get planners used to the new systems. If the system is built in a modular fashion, more advanced models can later be substituted. Suitable output is very important.
 - b. The creation of the planning data base involves striking the right balance between what already exists in corporate data bases and what the models really need. Unnecessarily elaborate data requirements mean expensive data collection. If some data does not exist, it may mean the model is not suited for the company.
 - c. A project which cuts across

several corporate functions is only possible if high level management support is available. Almost the same points mentioned by Troesch [83].

2. From the point of view of data handling, the following features of the described corporate planning system are important:
 - a. A centralized data base, containing only relevant data. Setting up a corporate planning system represents a commitment to the maintenance of a comprehensive data base.
 - b. The data base also acts as a data interface between application programs, permitting the use of different programs in the same work session, emphasizing their interdependence. At the same time they can remain modular and hence, exchangeable.
 - c. Interactive data manipulation. This applies both to the input preparation and output analysis phase of running an application program.

3.4.2 Decision Support and Interactive Systems:

Corporate planning systems are designed for a well-defined set of problems and application programs.

We call a system (somewhat arbitrarily) a decision support system (DSS) which is used when the problems are not well defined and the use of application programs and data cannot be totally anticipated. Donovan [24] gives a description of the problem environment which a DSS addresses:

- The problem or the planner's conception of the problem may change.
- The data necessary to carry out a study may change. Available data may be interrogated in different ways.
- Sophisticated analytical methods and data displays are required.
- Answers may be needed quickly. The planner must be able to respond rapidly to a request from an executive or a regulatory agency. This could be any nonroutine data request, as a simple query or a whole report, a request to restudy a certain problem under new assumptions, or a so-called "what-if?" problem.

A computing environment to properly support this kind of planning activity has two main components:

A data management capability which

- a. includes an interactive component that can introduce, validate, query, and update new data sets.
- b. allows to integrate data from different sources into a uniform data organization. In Donovan's paper a relational data base (see Appendix A for model description) is chosen, because of the simplicity of its data structure. Analytical capabilities. This includes special purpose application programs as well as general purpose analytical facilities (statistical, LP perhaps, etc.). A modular structure is again required to allow the integration of programs of different origin.

Such a problem characterization can clearly apply to long-term (regional) planning.* The proposed system structure is in fact the same which we encountered in the previous section with one major difference: The emphasis is on being able to accommodate an unpredictable collection of different programs and different data sets.

Not surprisingly, similar structures have been proposed in related areas, different uses leading to slight variations in design.

Agee at EPRI [0] proposes a system which serves as a service center and data clearing house for programs and data for a segment of a nationwide nuclear research community including EPRI, utilities, vendors, and national laboratories. It is based on two existing systems called JOSHUA (see Honeck [49]) and DATATRAN (see Kopp [54]) and is intended to be largely system hard- and software independent. The system contains a large hierarchically structured data base, data management functions, and a set of modular, interactive application programs. Agee places emphasis on the data base design which will constitute a major effort in view of its attributes: There will be large amounts of data, both experimental and derived, coming from different

sources, of different type and life expectancy, some likely to be incomplete. There will be local and remote on-line access and graphic display capability.

The whole concept is very similar to one proposed by MASUD [58] to be used by the U.S. national electric system planning community. Masud's proposal has the flavor of a long-term goal, Agee argues, however, that such a centralized service is needed now and would pay for itself immediately by making new data and programs available to the industry on a timely basis. He does not see any significant technical problems.

At the other end of the spectrum, we find systems which serve the traditional areas of power system analysis (load flow, stability short circuit) where the whole emphasis is on interactive computing, data base problems are of secondary importance. Some of the papers on this subject are listed in the bibliography. Here we make a few general observations.

- Interactive computing is really a misnomer, as the bulk of interaction takes place in the input and output phase, even if the program is run in the foreground. Examples of true interactions with the program flow do exist, however (see Undrill [84]). In our view, the data handling aspects are more important, especially in the planning environment.
- The actual hardware architecture may differ significantly. In one approach each user has his own machine (a physical mini [84] or a virtual machine [24]) accessing a common data base. In other implementations a mini is attached to a large CPU which does the heavy computation and stores the data. The mini is used for local display support. Lastly, several systems exist where the whole system is on one CPU [68, 18, 14, 43], whether in-house or on a time-sharing system.
- In some systems the data base is split into a master data base and a study data base or working file [84, 51 68]. The idea is to preserve the integrity of the master data base by making a copy of the needed data and applying modifications only to the copy. This is the same theme encountered in some planning data bases and in the Northern States Corporate planning system.

*The DSS provides the means to empirically explore the large areas of uncertainties, to establish tradeoffs and risks, and to better define the problem where analytical methods may fail.

- In interactive applications the emphasis is mostly on input and output modifications, sometimes on interactive programs. Hardly any attention has been paid to an interactive query system. For such a system to be useful, a planning environment as that proposed by Donovan would have to be assumed. Examples of such query systems exist (see e.g., D'Ettorre [23]), but the time of broad acceptance will only come when decision support systems or executive systems in power system planning have become a reality.

3.4.3 Decision Analysis:

Decision analysis (DA) is a method to structure and formalize decision making in a complex planning environment, especially with aspects of uncertainty, where informal and intuitive methods can no longer be satisfactorily applied. Two ideas are of central importance:

- The identification of the structure of the problem relationship
- The treatment of uncertainty including aspects of subjective probability, different risk behaviors and of assigning an economic value to the elimination of uncertainty.

DA has not been applied too frequently in the past, partly because of a reputation of being too academic and of little usefulness for practical problems. Recently interest in the methods of DA has been revived, as users have recognized its power in identifying the structural aspects of uncertainty. Several publications in the electric utility area demonstrate DA's usefulness [25, 9, 52, 45]. This is especially true in situations where the set of choices is limited, the uncertainty can be relatively easily quantified, and there is a single objective or, at least, clearly definable tradeoffs among conflicting objectives. Not only does DA lead to a "best" decision policy, but the documentation of the process in itself is valuable:

- The decision maker gains in understanding of the problem, and of the preferences (values, risks, tradeoffs) which now are explicit.
- The documentation of the decision process can be used in dealings with regulatory agencies.

DA is a multistage process decomposed into 3 or 4 phases depending on the author (Howard, Keeney).

- First, the structure of the problem is

developed. In simple cases this structure can be represented by a decision tree, in more complex situations several computer programs may be required as a model. Structuring includes identification of the decision makers, identification of alternatives, and definition of objectives.

- Second, the consequences of each alternative are described and analyzed and the associated uncertainties identified.
- Third, the relative preferences of the decision maker are described. Here the tradeoffs among conflicting objectives are identified, risk and time preferences are established. The set of preferences is encoded into a so-called utility function which is evaluated for each possible outcome of the decision process. That decision path which has the highest expected utility value represents the optimal decision path. It goes beyond the possibilities of this review to discuss the elaborate and often cumbersome steps of establishing a valid decision function. Examples are given in [9] and in [52], a detailed reference is [70].
- A fourth phase includes evaluation and sensitivity studies.

An iterative process in which the models are continuously refined is suggested by Howard to arrive at the best decision.

Of the three references which discuss the use of DA specifically for long-range planning, the one by Sullivan and Claycombe proposes a simple decision tree model, Keeney and Nair discuss the complexities of choosing a utility function with multiattribute objectives, the SRI report [78] shows the application of DA to the problem of whether a nuclear unit should be built by the Federal Mexican Power Commission.

4. Summary, Recommendations

4.1 Summary

The goal of this survey has been to give a self-contained assessment of the status of two aspects of regional planning: regional information systems and decision support systems.

The data bases at the reliability councils contain load flow base case libraries for about ten years a stability data; in a few cases the

addition of reliability data is being considered. Load flow data is also collected on a national level by NERC to study national cases excluding WSCC and RCOT. The councils also collect data for the EEI and the FERC; this data is usually not machine readable and not used elsewhere. Among the exceptions are MAAC and NPCC: the MAAC data base is considerably larger because it is, in fact, the PJM planning data base. The NPCC data base is organized fundamentally differently. Its organization eliminates redundancy, facilitates updating and generally provides more flexibility in use, expansion, and modification.

The conventional system works well for present use and today's amount of data. As soon as the amount or types of data is increased, or additional flexibility is desired in system or load representation, the new approach is more attractive. For any reliability council or regional planning organization intending to collect additional data or making the data available for other use, a serious review of the principles underlying the alternate organization is appropriate.

The regional and national data collection and information system are all in a phase of improvement. In correspondence with the amount of data involved and the intended use, NERC, EEI (-EPRI?), and FERC are pursuing solutions of differing complexity. To the NERC effort the concluding comments of the last paragraph apply; in the case of the EEI reliability data base, much interest in consolidation, avoidance of duplication, and extension of the data collection effort is in evidence. (See [0], [30].) The RIS system represents an advanced solution to the FERC's data handling requirements. It seems important, however, to try to extend the resulting benefits to (a) other related data collection efforts (e.g., Order 383/4); and, (b) interested state agencies. In both cases one of the main benefits to utilities would be a potential reduction in the reporting burden.

In the area of decision making support systems, the industry is using corporate planning systems of varying degrees of sophistication with emphasis on financial analysis. More general planning systems are being proposed. Interactive capability has become very common in load flow studies and is being used for other applications as well. Decision analysis is being rediscovered: it may become a useful tool to analyze the increasingly complex planning decisions. The area of

decision support systems has good mid- to long-term potential. The interrelatedness of technical and financial planning, of technical and contractual negotiations, the convergence of technical and corporate decision making all have a strong effect on the structure and the process of decision making. Presently a decision support system of the proposed architecture is limited in the amount of benefits it can provide by the existing process of utility decision making more than by anything else.

4.2 Recommendations

Based on this survey, we recommend three areas for potentially fruitful research (with priority and time frame indicated):

1. Regional data management (A, long-term)
2. Decision support for regional planning (A, long-term)
3. Transmission reliability data base (B, mid-term).

4.2.1 Regional Data Management:

If one looks at the regional data management as a whole, one identifies several aspects which deserve attention:

- a. Elimination of redundancy in regional data bases (see NPCC approach).
- b. Elimination of reporting duplication. In principle, the utilities should not have to report a data item more than once. If the data exchange system is set up well, anybody who needs that data item can get it from "the data base."
- c. Elimination of unnecessary transformation from machine readable form into hard copies and back.
- d. Update authority and data consistency. The fundamental update authority resides with the decision making utility. A simple mechanism should exist which transfers this update authority to other levels of the hierarchy allowing to maintain data consistency, even among the different representation of the network.

- e. Data sharing on a national basis. The FERC has approached the state regulatory commission with the idea of making the RIS and its data base available to them by remote access. Alternatively, they could obtain a copy of the data base. The potential for cooperation is great, the institutional barriers may be significant.

We recommend that an in-depth study of regional data management be conducted, addressing but not limiting itself to the points raised. Subproblems should be defined and evaluated in terms of the impact on better regional coordination and planning, and (very important;) the expected interest and cooperation of the utilities. Any identified subproblem will correspond to a large amount of work in coming up with a well-defined and still general data handling scheme. Only the subproblem with highest priority should be carried through. In view of the "development" nature of the problem, EPRI, involvement might be considered.

4.2.2 Decision Support in Regional Planning:

We have not said much about the use of decision support systems in a regional context, simply because most activity is within the utility. Most of the reasons, however, for having such a system within a utility would apply equally well in the slightly broader context of planning interactions between individual utilities and even between utility and a planning commission. However, neither the institutional structure nor the mutual motivation exists at present to make the use of such a system a practical proposition. But fundamentally, some of the same issues exist:

1. A need to better quantify tradeoff relationships, criteria, personal preferences, etc., in order to be able to evaluate proposals more objectively.
2. A need to bring the technical evaluator, i.e., the engineer, closer to the decision maker. The decision maker needs immediate access to detailed technical judgement.
3. A need to bridge the gap between financial and engineering evaluations.
4. a need to make contractual negotiations a more direct part of economic-technical

Efforts to address these issues should go in two directions:

1. Better tools to quantify all imprecise and uncertain aspects of planning. This includes decision analysis and interactive computer support to empirically (i.e., through simulation) determine sensitivities or tradeoffs or, say, risk preferences.
2. Provide a system which allows decision makers to come "closer together." This need not be in a physical sense, but it corresponds to the idealized situation where everybody concerned (regulator, one or several companies' executives, engineers) sits in one room with access to data and analysis and simulation programs. At the very least, everybody would thus have access to a common set of information. But in addition the inherent iterative procedure of arriving at a consensus could be speeded up dramatically.

These two goals are just as important in the context of a single utility where they have been partially achieved, as in the regional context where they have not been attempted or even considered.

We recommend, therefore, that the DOE consider as long-term speculative research an effort which would attack the two issues in the regional context. On the technical side, this would involve developing new models, say for contract negotiations, new interactive support for on-line solving, querying and display techniques both for information intended for the executive and the engineer. The potential for significant institutional problems is recognized, but it is hoped that a favorable testing environment could be found.

4.2.3 A Transmission Outage Data Base:

Reliability studies in power systems planning are becoming increasingly important. As a result, a great deal of attention is being directed towards establishing a comprehensive data bank for availability/outage data on generating equipment. Much less has been done in the past on collecting reliability data for transmission lines. This is partly because the impact of a transmission line outage is usually not as critical as the loss of a large unit, but also because availability data for transmission lines

cannot be used that easily. The time between outages is not determined by the same type of factors which dominate generating equipment and which can be adequately modeled by simple random processes. Causes for outages have regionally different characteristics (lightning, ice, snow pollution, etc.) and are often strongly correlated. Thus the necessary mathematical model is very complex.

Nevertheless, there is increasing interest in developing a transmission outage data base (Ontario Hydro, NPCC; see also paper by Carta [12]). An additional justification for collecting this data is that it can be used as evidence in the regulatory process for transmission line approvals.

This problem encompasses all aspects of setting up a data base for a given application area. Of particular significance are the questions of what data to collect, and how to organize it. Should it be collected by outage type or by geographical location? Is it justifiable to classify data both ways? How important is the identification of the manufacturer, and the designer? Can a "standard" definition of variables be achieved? Is it meaningful to have a national data base or would it be more meaningful to have them in geographically more homogeneous regions?

This project again has the character of a development effort which could best be carried out by EPRI in conjunction with participating utilities.

5. Bibliography, References

This section contains in alphabetic order, all titles which are part of the bibliography, but also some titles only used as references in the text.

The guide to the bibliography consists of topical subject headings with pointers to the corresponding references in the list (only first author is mentioned.).

Not surprisingly, there exists relatively little which is published in the specific areas of "Information Transfer" and "Decision Making" in power system planning. Several other related important areas have been included. Not considered were documents which relate to the areas of generation planning, transmission planning, or energy supply models unless data handling or decision

Documents which are not readily

publicly available are marked with an asterisk (*).

5.1 Subject Areas

Planning Data Base Organization

Keress	Auges [2,3] EDF
Blair CEGB	*IBM Manual on PSP
Moore	NPCC

Interactive Systems

Carter [14]	Peon
Coombe	Puettgen
D'Ettorre	Roman
Hirsch [42,43]	Schlaepfer [75]
Jordan	Undril

Decision Analysis

Bolinger	Raiffa
Esser	SRI Project 6496
Howard	Sullivan
Keeny	

Corporate Planning, Executive,

Decision Support Systems

Agee	Lienhard
Detroit Edison	Naylor
Donovan	Neale
Hamilton	Peon
Honeck	Sager [73,74]
Jordan	Troescher
Kopp	Wood [88,89]

Regional Planning Research Needs

Breyer	IEEE [47]
EPRI [28,29]	Masud
ERDA [31,32]	RANN Report
Uri	FERC [33], Vol. 1

Hierarchical Systems

Conant	Schweepe
Mesarovic	

Data Collection Efforts

EET [26,27]	DiMorino
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SECTION 8.

SUMMARY OF CONCLUSIONS

Generation

a) The focus of previous advances in generation planning methodology has been greater modeling accuracy in system reliability and production operations. This is true for both the simulation models used in analysis and the mathematical programming models used in synthesis. There have also been limited advances with respect to making planning models more computationally efficient and, simply, easier to use. However, growing complexity in power system operation (e.g., new technologies and system interconnections) have tended to mask the benefits in this area.

b) Improvements in the methodologies and models used in generation planning must be based on utility needs and concerns. Much effort has been devoted to the development of tools which have little immediate practical application resulting in a gap between published methodologies and the level of implementation. This gap could be narrowed if, with the introduction of a new methodology, parallel efforts were made to demonstrate computational feasibility for large systems and to indicate a procedure for acquiring any necessary new data.

c) None of the models reviewed is directly applicable to multiple utility regional planning problems although it may be possible to adapt them for this purpose. Assuming the problem size is manageable, the important issues become the questions of the reliability of interconnected areas, cost allocation, and multi-area generation dispatch. Furthermore, the objective of regional planning is not necessarily the sum of total discounted costs for all utilities, due to complicated institutional factors and the inevitable issue of equitable sharing of costs and benefits over the geographically distributed service area.

Transmission

a) Currently, only deterministic tools including load flow and dynamic simulation play a significant role in the actual planning of large scale transmission systems. However, probabilistic reliability analysis is being explored by several utilities in the U.S. Several automated expansion programs have been developed, but applications to date with such methods have been limited.

b) Using the full Newton or the decoupled Newton methods, single AC load flow solutions for

systems of several thousand busses can now be obtained rapidly on medium-size computers. Algorithmic development has progressed to the point where the requirement of computational efficiency has been largely satisfied and where the emphasis on improvements has been transferred to user-computer interaction. In newer program designs, the abilities to rapidly change specifications, obtain a new solution and look at particular results have become of major importance. These needs have led to the development of interactive load flow programs.

Future work in the load flow program area will probably concentrate on providing (1) better interactive features for single case computations and (2) faster algorithms for use in automatic contingency analysis.

c) The more advanced dynamic simulation programs have the capability of detailed machine representation combined with a capability of solving large networks.

For planning purposes, as opposed to detailed design considerations, the need for improvement is in speed of execution and input/output handling rather than in more detailed representation.

d) At present, most planning procedures employ deterministic contingency or disturbance criteria for both security (dynamic) and adequacy (static) assessment. Load flow and stability programs are used to verify that a system meets the defined criteria. However, it is not clear that deterministic criteria assure reliable system performance and whether alternative system configurations which are designed to meet these criteria result in equally reliable performance.

Probabilistic procedures based on automatic contingency analysis or Monte Carlo techniques are capable of computing probabilistic reliability measures of system adequacy. However, simplifications are presently required in network models. Progress in this area is dependent on improvement in computer hardware/software for increased speed of system failure and on the formation of reliability indices useful for planning and design. In the near term a most useful application of probabilistic reliability computations appears to be to evaluate and sharpen the deterministic criteria presently used to assure reliable transmission systems. There are presently no tools that are capable of predicting security (dynamic) indices for large scale systems.

The reliability criteria need to be reviewed through quantitative evaluation of the worth of reliability to the end user.

e) The gradient search, linear programming and integer programming approaches to single stage optimization each have their strengths and weaknesses. A general problem with all such models is that both the system representation and the expansion objectives are, of necessity, much simplified and do not cover the range of concerns a planner may have.

The basic problem inherent in any single stage expansion process is that it does not consider the timing of installations. Through-time optimization algorithms capable of including inflation and interest rates as well as year by year operating costs have been proposed based on both integer programming and dynamic programming approaches. For large scale systems, heuristic approaches appear to be the preferred choice. However, through-time optimization algorithms are obviously even further away from successful application than are single stage optimization models for large scale system planning.

Energy Supply/Demand

a) The models examined were all developed for the purpose of energy policy planning and analysis. They have been used for analysis of a variety of public policies affecting the supply and demand of energy. Most contain a regionalized articulation of the electric utility sector. In spite of this, the models have found little regional application, partly because there is a scarcity of identifiable users. More importantly, it is likely that the aggregation and treatment of behavior of the utility sector within a regional aggregate of these national models is far too gross to be persuasive in any regional forum.

b) To the extent that power systems planning is defined as to what type of plant, of what size, should be built when and where, for the most part, the models reviewed are of little use. The models sacrifice essential detail necessary to address this specific planning problem. The models generally assume constant returns to scale, treat issues of reliability in only a cursory fashion if at all, lack the detailed geographic characteristics for the region, the intra or inter-regional generation and transmission possibilities, and have no detailed plant-by-plant production simulation capability.

c) To the extent that power systems planning can be described as the more classical economic notion of discovering and removing inefficiencies in supply and pricing of electrical service, most of the models examined do not apply. Instead, the energy system models generally assume cost minimizing behavior by the producers of electricity, assume away the economies of scale in production, neglect completely the problems of joint costs, and make no attempt to quantify externalities.

d) To the extent that the purpose of power systems planning is the planning of joint production and transmission facilities in and among regions, none of the models examined apply precisely. The models are too gross in geographical detail, they do not capture the properties of dynamism and diversity of load, and again treat reliability in much too cursory a fashion.

e) To the extent that regional power systems planning can be defined as estimating a priori a region's electricity sector response to changes in prices of factor inputs, such as fuel or capital, or changes in emission standards, then several of the models potentially apply. However, none of the models discussed is superior to all others for application to all questions of regional interest.

f) Though none of the models reviewed can stand alone as a power system planning tool, each of them can contribute useful information. The models represent a cross-section of techniques and approaches. As a result, they perform different functions and their application potential varies.

g) The fundamental weakness of energy-supply/demand models is that features of the industry which require regulation such as economies of scale are assumed away. Each analyzed model could address at most one-third of the important regional planning policy questions posed.

System and Processes

a) The data bases at the reliability councils contain load flow base case libraries for about ten years and stability data. In a few cases the addition of reliability data is being considered. Load flow data is also collected on a national level by NERC to study national cases excluding WSCC and ERCOT. The councils also collect data for the EEI and the FERC; this data is usually not machine readable and not used elsewhere. Among the exceptions are MAAC and NPCC: the MAAC data base is considerably larger because it is, in fact, the PJM planning data base. The NPCC data base is organized fundamentally different. Its organization eliminates redundancy, facilitates updating and generally provides more flexibility in use, expansion, and modification.

The conventional system works well for present use and today's amount of data. As soon as the amount or types of data is increased, or additional flexibility is desired in system or load representation, the NPCC approach is more attractive. For any reliability council or regional planning organization intending to collect additional data or making the data available for other use, a serious review of the principles underlying the alternate organization is appropriate.

b) In the area of decision making support systems, the industry is using corporate planning systems of varying degrees of sophistication with emphasis on financial analysis. More general planning systems are being proposed. Interactive

capability has become very common in load flow studies and is being used for other applications as well. Decision analysis is being rediscovered and may become a useful tool to analyze the increasingly complex planning problem. The area of decision support systems has good mid- to long-term potential. The interrelatedness of technical and financial planning, of technical and contractual negotiations, the convergence of technical and corporate decision making all have a strong effect on the structure and the process of decision making. Presently a decision support system with a new, more general architecture is limited in the amount of benefits it can provide by the existing process of utility decision making more than by anything else.

c) The attainment of complete coordination of planning to meet regional objectives will not be an easy task. The normal restrictions on system developments are due to small local obstacles such as an impossible right-of-way. At some time in the planning process these restrictions must be factored into the solutions. With the normal practice the local utility does its own planning and then coordinates the results with its neighbors, making changes as necessary to insure a proper fit of facilities planned to be added.

d) Within the laboratories, the conception of regional planning is very largely one of concern over regional resources whether they be air, water, fuels, land-use or other related regional resources. Within the industry the question is primarily one of optimal siting (and timing) of facilities. This process, while giving some attention to resources, is more concerned with economy and reliability of energy supply and has a different emphasis in its implicit objective function.

e) The use of interactive computer graphics can facilitate the regional planning process whatever the perspective of the practitioner. In its most rudimentary manifestation, the preparation of graphic depiction of tabular or numeric data clearly enhances the assimilation of information.

In the planning process, a complex one involving many variables and constraints, graphic depiction of data results in a clearer understanding of the relationships. This is particularly true when the data being depicted is residual from calculations, including analyses performed for parametric or sensitivity analysis. To "close the loop" and permit user interaction in such evaluations is useful and improves the understanding of the planning and modeling process.

f) One question which has a tendency to arise from time-to-time is the question of whether there should be a "grand design" model (or a set of integrated submodels) which encompasses the entire planning process. Whether one views this question from an industry standpoint or a DOE laboratory standpoint, the availability of such a comprehensive tool appears very attractive. When the analytical requirements, the data needs, and the practical aspects of the process are considered in the light of this question, it becomes evident that such a

system of models would be extremely difficult to formalize and the total system would contain complexity unwarranted by the nature of the planning process.

Although the construction of such an all-encompassing model does not appear to be practical, it would be useful to formalize a methodology for a building-block approach consisting of simple basic submodels relating to specific aspects of the overall planning process

g) The marketplace today offers a variety of graphic display and interactive devices. Technology has progressed to the point at which utilization of graphic systems is commonplace as a result of established technical and economic feasibility.

At each of the DOE laboratories a representative array of equipment is available for use and is being utilized. The graphic systems are supported by computer systems which give users the capability to perform modeling and to store and retrieve data.

h) Each DOE laboratory is establishing large data bases. The components of these data bases are similar, although each laboratory has a regional responsibility for the area in which it is located. Thus although there may be limited redundancy of data there is a responsibility to prepare and maintain files which is being met at each of the laboratories.

SECTION 9.

SUMMARY OF RECOMMENDATIONS FOR FUTURE RESEARCH

Generation

a) Load management techniques and unconventional generation resources such as solar and wind power offer alternatives for satisfying at least part of the expanding electricity demand. These should be modeled and included in the planning process to provide more powerful optimization methods.

b) Until more powerful computers or mathematical techniques become available, the generation planning problem must be reduced in size by means of equivalent representation, space or time decomposition, etc. for present methodologies to be practical for regional application.

c) Cost and benefit allocation should be reflected in the generation planning models so that individual participants are aware of their status.

d) Uncertainty should be considered to a greater degree. Factors such as construction delays, major disruptions of fuel supply, etc. are not incorporated in existing models for automatic generation expansion.

e) Generation planning should be integrated with transmission planning and with the regional energy model, to preclude the need for manual iterations among the models.

f) If the regional planning entity is mandated to optimize the social costs, it will be necessary to include them in the objective function.

g) Generation planning models should be altered to consider the restrictive impact of the growing scarcity of basic inputs to power supply, such as capital, land and fuel.

h) The benefits and feasibility of applying the frequency and duration method of reliability calculation to interconnected systems should be determined.

i) There is a need for a basis for more effective coordination of the reliability criteria for generation with those of the transmission and distribution systems.

j) Field measurements should be made to verify models used in assessing environmental effects.

k) More automation is needed in the process of exploring the sensitivity of economic analyses to variations in future parameters and conditions.

l) Regional and national studies should be made to assess additional long-term costs arising from short-term compromises due to corporate finance considerations.

m) Methods should be developed which can more clearly integrate tariff requirements and the corporate finance implications into the choice of an economic expansion plan.

n) A probabilistic production cost method should be used, which incorporates economic interchange with transmission limitations and which reflects unit commitment effects.

o) The "interactive" approach to automated planning should be emphasized, including the development of an appropriate data base and data base management system.

Transmission

a) Efforts should be made to determine the effects of alternative deterministic planning criteria on system reliability and cost, and to forecast the potential improvements in system effectiveness that could be obtained if transmission systems were planned according to probabilistic reliability criteria.

b) Methodologies for probabilistic reliability assessment should be explored.

c) A better understanding is needed of the relationship between network parameters and the properties of the network, both in a steady-state and a dynamic sense.

d) Stochastic load flow techniques should be developed which account for significant uncertainties in transmission planning.

e) Refinement is needed in system component representations and in load modeling for transient and dynamic simulation.

f) Eigenvalue analysis should be encouraged for use in multi-machine system stability investigations, and work should be continued in the development of mid-term and long-term time-domain dynamic stability programs.

g) Existing DC models for transient and dynamic stability studies should be refined and validated for accuracy, then expanded to handle multi-terminal DC lines effectively.

h) Present optimization techniques should be examined to uncover any limitations when they are applied to large scale transmission planning, and to determine which subproblems of the planning process can utilize optimization techniques.

i) Monte Carlo simulation should be explored to determine in which subproblems it may be useful.

j) There are many shortcomings in present solution techniques for multi-level and vector optimization problems which include uncertainty in system models and input data. These should be improved.

k) Automated capacity expansion techniques should be developed which inherently consider the uncertainties associated with demand forecasts and construction times.

l) A great deal of research could be directed to the basic problem associated with model decomposition. Any tools developed for regional analysis that are to be computationally attractive must be decomposable into generalized sub-models which themselves can be assembled to study a particular aspect of a problem.

m) A more complete and accurate transmission outage data base should be developed.

Energy Supply/Demand

a) A model should be developed that is specifically designed to study regional power systems problems. Present models are incapable of evaluating the impact of regional planning on electric power systems.

b) The uncertainty about basic parameter values and future trends now inherent in electric energy system problems and its potential impact on the planning process needs to be assessed, and new models designed accordingly.

c) If energy systems models are to be integrated with other planning models, the problem of multi-utility concerns needs to be resolved.

d) An integrated set of interacting models should be developed for regional energy planning rather than a single all-encompassing model. The set would allow problems to be treated in adequate detail while avoiding the cumbersome size and prohibitive computation that a single model would require.

e) Some clear areas of policy research for which there are no appropriate general models are:

1) Effects of environmental regulation on the use of the various energy resources such as coal

2) Long term effects of the price of electricity on regional industry and commerce

3) The effects of proposed new pricing schemes on generation and expansion plans

4) Effect of capital availability on efficiency and reliability

5) How will regions utilize the fuel options available to them

6) Impact of nontransportable energy sources.

System and Processes

a) There is a need for an in-depth study of regional data management. Subsets of the data management problem should be defined and evaluated in terms of their improvement of regional coordination and planning, and whether utilities have any interest in the problem.

b) Systems should be developed to better quantify all the imprecise and uncertain aspects of planning, and to allow decision makers to come "closer together", at least in the sense that they have access to a common set of information.

c) More regions should be encouraged to form operating pools and ultimately to expand to fully coordinated pools with planning included.

d) Councils should spell out normal design standards with carefully worded criteria. Hazy and undefined terms have little value.

e) A long-term plan should be developed for the areas of application of computer graphics to regional planning.

f) Presently available DOE laboratory graphics systems should be exploited.

g) Capabilities within the DOE laboratories for special purpose planning studies and analyses should be expanded.

h) A plan should be developed for interaction among the DOE laboratories, including shared use and development of regional planning systems.

i) The development of regional planning systems should be supported by funding and by increased availability of DOE laboratory resources. The availability could be improved by distribution of information describing graphic systems, computational models and data bases.

APPENDICES

OF

Philadelphia Electric Company

APPENDIX A

Limited Energy

Limited energy generation deserves a special mention. This type of generation could very well be the most economical type of generation to add but be unacceptable due to the important failing of insufficient energy capability to support its kw capability.

Limited energy generation is defined here as capacity which has large restrictions on its production of kWhrs of energy. Some forms of such capacity are conventional hydro, pumped hydro, batteries and compressed air.

It is obvious from the hourly variation of load that all generation does not have to operate continuously. Indeed the top mw load on the daily load cycle (Figure A-1) shows a requirement of only a few hours of operation. Some limited generation will be useful; the question is how much. Basically, limited energy generation must have the capability to supply the energy requirements of the mw block on the load cycle on which it is operating. If limited energy generation was supplying the top 500 mw on the load cycle in Figure A-1. It would have to supply all the energy between 6800 mw and 6300 mw. This can be found by integrating the load cycle from the peak down to the 6300 mw level. If this amount of energy is not available, then the full capacity of the limited energy generator cannot be used to make up the capacity needs of the system. If the load cycle in Figure A-1 is integrated in steps from the peak load down we can produce a plot of capacity in mw off the peak versus the energy requirements of this peaking capacity (Figure A-2). By entering into Figure A-2 with a capacity value, we can determine the energy requirements. If we enter the curve instead with energy capability, we can determine the mw that can be served counted in the capacity makeup (provided of course this doesn't exceed the maximum mw capability); i.e.,

700 mw generator with 4000 mwhrs capability. Entering Figure 3 with the available mwhrs we find that the capacity is only worth 580 mw or 83% of the total.

In addition to meeting the energy requirements of a daily load cycle, limited energy generation usually must also be capable of supplying the energy requirements over a weekly load cycle. If the entire energy storage had been used on a particular day and could not

Figure A-1. Typical Daily Load Cycle

Figure A-2. Energy Requirements for Peaking

be completely replaced during the night (this is a typical situation for pumped hydro), then the energy available for the following days would be less than the first day. We needn't go past a week in analysis because the reservoir can be refilled during the lower load level weekends. The amount of useful limited energy is a function of the load magnitude, the load shape, the type of limited energy generation, the energy replacement capability, and the ratio of on-peak energy costs. Where the limited energy is conventional run-of-the-river hydro with limited storage capability, stream flows must be taken into consideration. This is accomplished by applying probability techniques to available historical stream flow data. The maximum level of limited energy that could be used by a system would typically be below 15% of total installed capacity.

APPENDIX B

Method of Optimal Mix [8]

The optimum mix of nuclear, fossil, and combustion turbines can be determined using reserve requirement calculations, economic comparison, and a load duration curve.

Assume that reserve calculations show that 20% (1) reserve is required to meet the reliability criterion. The load duration curve will give us information on how many times a year each load level will exist. The optimum mix of the above type of units will be the combination of generation which will have the minimum annual cost for the expected hours of operation in a year. This can be expressed as a function of the fixed costs and those costs which vary with the operating hours of the plant as shown in the following equation:

$$T = AK_a + BK_b + F + (Hf + v) X$$

where

- T = Total Annual Costs, \$/kw/year
- A = Production Plant Capital Costs, \$/kw
- B = Transmission Capital Costs, \$/kw
- F = Fixed Annual Operating and Maintenance Costs (including nuclear insurance), \$/kw/year
- K_a = Annual Levelized Carrying Charge Rate for Production Plant Capital, %/year
- K_b = Annual Levelized Carrying Charge Rate for Transmission, %/year
- H = Production Plant Net Heat Rate, btu/kilowatt hour
- f = Fuel Cost, \$/btu
- v = Variable Operating and Maintenance, \$/kilowatt hour
- X = Hours/year of operation

Note that the expressions $AK_a + BK_b + F$ and $(Hf + v) X$ represent the fixed and variable costs, respectively.

Assume that the available choices of generation are nuclear BWR, fossil oil-fueled, and combustion turbines. Further, assume that the combustion turbines are located close to the load center, the fossil cycling units are on the periphery of the system, and the nuclear units are remotely sited. Our basic data will be as shown below:

Generation Type	Basic Cost Data							
	A \$/kw	B \$/kw	F \$/kw/Year	K _a %/Year	K _b %/Year	H btu/kwhr	f \$/btu x10 ⁻⁶	v \$/kwhr x10 ³
Nuclear	400	40	3.5	14	15.5	10,500	0.2	0.12
Fossil	220	20	3.5	14	15.5	9,200	0.75	.27
Combustion Turbines	120	10	0.5	17	15.5	14,000	0.9	1.5

Summing all costs we then get the total annual cost as a function of operating hours for each type of generation:

$$T_{\text{nuclear}} = 65.7 + 0.002 X$$

$$T_{\text{fossil}} = 37.4 + 0.0072 X$$

$$T_{\text{combustion turbines}} = 29.1 + 0.031 X$$

It should be noted that the above costs are out of date. They are used here for illustrative purposes only.

- (1) It should be noted that reserve requirements will vary as the mix of generation changes. Any calculated reserve is based on a prescribed mix of generation. If the optimum economic mix differs from that used to calculate the reserve requirements, the reliability calculation will yield a different answer. Because of this effect, it may be necessary to "iterate" between percent reserve and mix calculations.

Figure B-1. Generation annual costs vs. annual operating time.

Plotting these three relationships as a function of the operating hours (Figure B-1), the minimum cost type of generation as a function of operating hours is obtained. This information is then transferred to the load duration curve (as shown in Figure B-2) which relates hours to peak load. It can be seen that a minimum cost mix of generation for this example would be:

Nuclear BWR = 50%
Fossil Cycling = 14%
Combustion Turbines = 36%

This is simplified example and does not include limited energy generation which will reduce the combustion turbine requirement.

Figure B-2. Optimal mix based on given annual costs illustrated in Figure B-1.

APPENDIX C

Loss of Load Probability [4]

The two important elements in calculating system reliability by this method are generation availability and load variability. These are generally called the generation (or capacity) model and the load model. These elements and the mechanics of the method are discussed in this Appendix.

Generation Model

Each generator has a probability of being unavailable for operation due to an uncontrolled or forced outage. This probability of forced outage may be expressed as a percent of the time, such as two percent. The probability of being available for operation in this case would be 100 minus 2, or 98 percent.

The forced outage of a generator can be considered an independent event; that is, it is neither influenced by the forced outages of other generators, nor, in turn, does it influence them. The probability of the coincident occurrence of a series of independent events is the product of their individual probabilities. The following calculations develop the generation capacity availability for a very simple example of two generators, each rated 100 mw, and each having a forced outage rate of 2 percent:

Probability of 200 mw available = $(.98)(.98) = 0.9604$
Probability of 100 mw available = $2(.98)(.02) = .0392$
Probability of 0 mw available = $(.02)(.02) = .0004$

Summation of all alternatives = 1.0000

This tabulation represents the capacity model which would be used for the example in reliability calculations. The total probability of all cases is 1.0 per unit, or 100 percent.

For the probability calculations of system reliability, a generation or capacity model for the actual system is developed in a similar manner. Every possible combination of unit availability must be considered, using the forced outage rates (or the corresponding availability rates) characteristic of each unit in each combination. The results are accumulated in a table of total available system generation and the associated probability of occurrence. For a larger example, which will be used later in a complete sample of calculation of system reliability, let us assume a system of four units--150 mw, 125 mw, 100 mw, and 75 mw. Each generator is considered to be in either of two states, "in" or "out." The number of combinational variations of (n) generators in either state is $(2)^n$. Then, for four generators, $n=4$ & $(2)^n = (2)^4 = 16$. All units are assumed to have a forced outage rate of two percent. The system of four generators would produce the following capacity model:

Unit-MW				Capacity Model	
150	125	100	75	Total Capacity Available (MW)	Probability of Occurrence
In	In	In	In	450	$(.98)^4 = 0.92236816$
In	In	In	Out	375	$(.98)^3(.02) = 0.01882384$
In	In	Out	In	350	$(.98)^3(.02) = 0.01882384$
In	Out	In	In	325	$(.98)^3(.02) = 0.01882384$
Out	In	In	In	300	$(.98)^3(.02) = 0.01882384$
In	In	Out	Out	275	$(.98)^2(.02)^2 = 0.00038416$
In	Out	In	Out	250	$(.98)^2(.02)^2 = 0.00038416$
Out	In	In	Out	225	$(.98)^2(.02)^2 = 0.00038416$
In	Out	Out	In	225	$(.98)^2(.02)^2 = 0.00038416$
Out	In	Out	In	200	$(.98)^2(.02)^2 = 0.00038416$
Out	Out	In	In	175	$(.98)^2(.02)^2 = 0.00038416$
In	Out	Out	Out	150	$(.98)(.02)^3 = 0.0000784$
Out	In	Out	Out	125	$(.98)(.02)^3 = 0.0000784$
Out	Out	In	Out	100	$(.98)(.02)^3 = 0.0000784$
Out	Out	Out	In	75	$(.98)(.02)^3 = 0.0000784$
Out	Out	Out	Out	0	$(.02)^4 = 0.00000016$

The probabilities above are for that exact amount of available generation shown, no more and no less.

Load Model

The load model that is used for the reliability calculations is developed to show the variability of daily peak loads on an annual basis. These load models are usually developed from historical records of daily peaks with adjustments made for future changes in characteristics. These load models may be quite complex, but a simple load model is used here to demonstrate their use. Eleven blocks of load are used to represent the whole range of daily peaks found in a year.

Load Model			
Load Blocks (MW)		Probability of Occurrences	Cumulative probability (probability load will be value shown or higher)
359	370	0.0012	0.0012
347	358	0.0085	0.0097
335	346	0.0384	0.0481
323	334	0.1105	0.1586
311	322	0.2107	0.3693
299	310	0.2614	0.6307
287	298	0.2107	0.8414
275	286	0.1105	0.9519
263	274	0.0384	0.9903
251	262	0.0085	0.9988
239	250	0.0012	1.0000
...	...	1.0000	

In the load model a cumulative probability table was developed which shows the probability that the load will be the value shown or higher (load duration).

Reliability Calculations

A capacity model which shows the probabilities for exact amounts of generation being available, and a load model which shows the probabilities that the load will be a certain level or higher, have now been developed. If the two models are matched up, the probabilities that the load exceeds the available generation can be found. Combining the capacity and load models to determine loss-of-load probability could just as easily be performed using a capacity model developed on the basis of the probabilities of availability of specific levels of generation or less, and a load model that had the probabilities of occurrence of an exact level of load.

The Reliability Model, shown in the following tabulation, is based on the coincidence of specific steps of generation being available and excess load occurring. These events (generation availability and excess load), like generator outages, are independent events, and the product of their probabilities is the probability of their coincidence. Columns 1 and 2 are the Capacity Model. For each level of available generation in Column 1, the probability that the load will be higher is taken from the Load Model and placed in Column 3. There is no load in excess of 370 mw, and therefore, there is no excess load probability for generation availabilities of 375 and 450 mw. The load is in excess of 350 mw 0.97 percent of the time, and exactly 350 mw of generation is available 1.882 percent of the time. The coincidence of exactly 350 mw of generation being available and the load being in excess of 350 mw is $(0.0097)(0.01882) = 0.00018259$ per unit of the time. Such calculations are repeated similarly for each level of generation availability.

Reliability Model

Generation Available (MW)	Probability this generation being available	Probability That loads Exceed Capacity	(2) x (3) Probability that load will be lost (i.e., load exceeds gen.) (4)
450	0.92236816	0	0
375	0.01882384	0	0
350	0.01882384	0.0097	0.00018259
325	0.01882384	0.1586	0.00298546
300	0.01882384	0.6307	0.01187220
275	0.0038416	0.9519	0.0036568
250	0.00038416	0.9988	0.00038370
225	0.00076832	1.0	0.00076832
200	0.00038416	1.0	0.00038416
175	0.00038416	1.0	0.00038416
150	0.00000784	1.0	0.00000784
125	0.00000784	1.0	0.00000784
100	0.00000784	1.0	0.00000784
75	0.00000784	1.0	0.00000784
0	0.00000016	1.0	0.00000016

Total Probability of Some Loss of Load 0.01735779

Saturday, Sunday and holidays are normally omitted in the preparation of load models. The load is sufficiently depressed on these days so that there is no measurable contribution to the annual risk of load loss by their inclusion. Neglecting these days there are 250 load days per year on which the load model is based. Taking the probability of loss-of-load from the probability model, 0.01736, and multiplying by 250 gives the number of days per year load may be expected to be lost.

$$(0.01736)(250) = 4.34 \text{ days/year}$$

The reciprocal of this number gives years/days--the measure of system reliability normally used in the technical literature on this subject.

$$\frac{1}{4.34} = 0.23 \text{ years/day}$$

APPENDIX D

Frequency and Duration of Capacity Deficiency

The frequency and duration (FAD) of different capacity margins (positive and negative) are calculated by combining an appropriately derived generation capacity model with a similarly derived load model. As the FAD method has been developed [5,6,7], both capacity and load are modeled as Markov processes. This requires the assumptions that the up- and down-times for each generator are statistically independent, stationary, and exponentially distributed random variables. Similarly, the sequence of daily load levels is assumed to be a stationary random process with the residence times at any load level exponentially distributed. The combination of capacity and load models relies on the independence of capacity reliability processes and load occurrence.

Capacity Model

System capacity may occupy a number of different capacity states, each corresponding to a combination of units in and out of service. The collection of possible states, with the probability and frequency

of occurrence of each state as well as the effective rate of departure from that state, constitute the capacity model. Unit failure and repair rates, and sizes are used to create the capacity model [5]. The probability and frequency may be specified for each exact capacity level, or alternatively accumulated for all capacity levels greater than or equal to each possible level—depending on how capacity and load models are to be combined to form the capacity margin model.

Load Model

Two basic load models have been suggested. The first model [6] views the system load cycle as a sequence of load levels, each possessing a probability of existence and transition rates to higher and lower load levels. The second model [7] treats system load as a continuous variable, described by two continuous functions: the load duration curve, and a "load-frequency" curve which gives the frequency with which load equals or exceeds any specified value.

Capacity Margin Model

The capacity margin (reserve) model consists of margin states, each equal to a capacity level minus a load level. The probability that a particular margin state exists is given by the product of the probabilities of the associated capacity and load states. The frequency of encountering a particular margin state is given by the product of the probability of the margin state and the summation of the rates of departure (upward and downward) from that state. Finally, the expected duration is given by dividing probability by frequency. The probability and frequency associated with all margins less than zero provide the reliability indices for the system.

Corresponding to the two load models, there are two ways to calculate the frequency and duration of any cumulative margin (margin less than or equal to a particular value). The first [5,6] combines a cumulative-state capacity model with a discrete-state load model to yield.

$$P(M) = \sum_{\text{load levels } L} P_{\text{load}}(L) P_{\text{gen}}(C-L-M)$$

$$f(M) = \sum_{\text{load levels } L} P_{\text{load}}(L) \{ [\rho_-(L) - \rho_+(L)] P_{\text{gen}}(C-L-M) + f_{\text{gen}}(C-L-M) \}$$

where $P(M)$ = probability of margin M or less,
 $f(M)$ = frequency of margin M or less,
 $P_{\text{load}}(L)$ = probability of discrete load L ,
 $P_{\text{gen}}(Y)$ = probability that capacity out equals or exceeds Y ,
 $f_{\text{gen}}(Y)$ = frequency that capacity out equals or exceeds Y ,
 $\rho_+(L), \rho_-(L)$ = departure rates from load level L up and down
 C = available system capacity

The second method [7] combines an exact-state capacity model with a cumulative-state load model to yield

$$P(M) = \sum_{\text{capacity outage states, } X} P_{\text{gen}}(X) P_{\text{load}}(C-X-M)$$

$$f(M) = \sum_{\text{capacity outage states, } X} P_{\text{gen}}(X) \{ [\rho_+(X) - \rho_-(X)] P_{\text{load}}(C-X-M) + f_{\text{load}}(C-X-M) \}$$

where: $P_{\text{gen}}(X)$ = probability of capacity outage X
 $\rho_+(X), \rho_-(X)$ = departure rates from capacity outage state X up and down
 $P_{\text{load}}(Y)$ = probability that load equals or exceeds Y
 $f_{\text{load}}(Y)$ = frequency that load equals or exceeds Y

For either method for computing $P(M)$ and $f(M)$, the average duration of a cumulative margin state M is given by $P(M)/f(M)$.

APPENDIX E

Load Duration Dispatch

Units are stacked vertically from bottom to top in order of increasing energy cost, each unit derated by its forced outage rate, until the area beneath the curve is filled. Energy costs may then be computed by multiplying the mwhrs for each type, represented by the area occupied beneath the load duration curve, by the associated energy cost (\$/mwh).

An example is illustrated in Figure E-1 based on the unit operating characteristics given in the table below.

Table of Unit Operating Characteristics

Unit	Type	No. of Units	Size	F.O.R.	Mw Capacity		Fuel Cost \$/mbtu	Heat Rate Btu/kwh	Energy Cost \$/mwh
					Total	Derated			
1	Nuclear	(2)	1000 mw	.30	2000	1400	.30	9000	2.7
2	Coal	(3)	600 mw	.20	1800	1440	1.20	10000	12.0
3	Oil	(5)	300 mw	.1	1500	1350	2.30	11000	25.3
4	Combustion Turbines	(30)	50 mw	.05	1500	1425	2.50	13000	32.5

Figure E-1. Annual load duration curve indicating contribution of each generation type to total energy produced.

APPENDIX F

Probabilistic Production Cost Evaluation

A brief heuristic description of the probabilistic method of estimating production cost is presented. The method grew out of a need to represent in a more satisfactory manner generator forced outages without forfeiting entirely the computational efficiency of the load duration approach described in Appendix E. For more detailed description of the probabilistic method refer to [13,14,15,30].

The effect of a forced outage on the expected energy generated by a particular generator is illustrated in Figures F-1 and F-2. Shown is the load duration curve (LDC) of a given system with generation dispatch according to order of merit--unit 1 being the most efficient, unit 2 the next most efficient, and so on to the N^{th} and least efficient unit. When unit 1 fails, the positions of units 2,3,...,N shift downward changing the energy generated by each, as shown in Figure F-2. Note that effect of the shift downward on the loading of units 2,...,N may be equivalently represented here by a vertical translation of the LDC upward by an amount equal to the capacity of unit 1.

Denote

$t(P_L)$ = LDC evaluated at load P_L , interpreted as time during a given period during which the demand equals or exceeds P_L megawatts.

E_i = expected value of the energy delivered by unit i during the time period.

C_i = MW capacity of unit i

P_i = probability that unit i is available

q_i = probability that unit i is not available

Ignoring maintenance requirements, the expected value of the energy delivered by unit 1 is given by

$$E_1 = P_1 \int_0^{C_1} t(P_L) dP_L, \quad (F.1)$$

representing the area occupied by unit 1 beneath the LDC.

Figure F-1. Generation dispatch with Unit 1 in service

In calculating the energy delivered by the second unit, two components of cost are considered. First, when unit 1 is available (with probability P_1), unit 2 will be loaded to supply system demand between the levels C_1 and C_1+C_2 . Second, when unit 1 is forced out (with probability q_1), unit 2 will occupy the lowest position under the LDC, supplying system load between the levels 0 and C_2 , as shown in Figure F-2. The expected value of the energy delivered by unit 2 is, therefore,

$$E_2 = P_2 \left[P_1 \int_{C_1}^{C_1+C_2} t(P_L) dP_L + q_1 \int_0^{C_2} t(P_L) dP_L \right] \quad (F.2)$$

Recognizing that

$$\int_0^{C_2} t(P_L) dP_L = \int_{C_1}^{C_1+C_2} t(P_L - C_1) dP_L$$

(which acts to shift the LDC up by the amount C_1), Eq. (F.2) becomes

$$E_2 = P_2 \int_{C_1}^{C_1+C_2} [P_1 t(P_L) + q_1 t(P_L - C_1)] dP_L$$

The influence of the availability of unit 1 on the operation of unit 2 may be reflected through the use of a modification of the load duration curve. An "equivalent load duration curve" (ELDC) is defined as follows

$$\bar{t}_i(P_L) = P_1 t(P_L) + q_1 t(P_L - C_1) \quad (F.3)$$

Substituting Eq. (F.3) into Eq. (F.2) yields

$$E_2 = P_2 \int_{C_1}^{C_1+C_2} \bar{t}_i(P_L) dP_L$$

which has a form similar to Eq. (F.1).

Figure F-2. Generation dispatch with Unit 1 forced out.

In order to evaluate the expected value of the energy generated by unit 3, the effects of outages of both units 1 and 2 must be considered (since the position of unit 3 under the LDC depends on the availability of units 1 and 2). The ELDC $\bar{t}_1(P_L)$ incorporates the effect of forced outage of unit 1. Unit 3 is, therefore, loaded according to this curve if unit 2 is available. If unit 2 is not available, the ELDC, $\bar{t}_1(P_L)$, is shifted upward by C_2 and used. That is,

$$E_3 = P_3 \left[P_2 \int_{C_1+C_2}^{C_1+C_2+C_3} \bar{t}_1(P_L) dP_L + q_2 \int_{C_1+C_2}^{C_1+C_2+C_3} \bar{t}_1(P_L - C_2) dP_L \right] \quad (F.4)$$

Defining an ELDC for unit 2

$$\bar{t}_2 = P_2 \bar{t}_1(P_L) + q_2 t_1(P_L - C_2)$$

and substituting into Eq. (F.4) yields

$$E_3 = P_3 \int_{C_1+C_2}^{C_1+C_2+C_3} \bar{t}_2(P_L) dP_L$$

The following recursive formula is used for developing the expected value for the energy generated by each unit n

$$E_n = P_n \int_{a_n}^{b_n} \bar{t}_{n-1}(P_L) dP_L, \quad n=1, 2, \dots, N,$$

where

$$a_n = \sum_{i=1}^{n-1} C_i, \quad b_n = \sum_{i=1}^n C_i$$

and

$$\bar{t}_m(P_L) = p_m \bar{t}_{m-1}(P_L) + q_m t_{m-1}(P_L - C_m)$$

For unit 1 the ELDC and LDC are identical; that is,

$$\bar{t}_0(P_L) = t(P_L)$$

After the expected energies for all generators have been determined using the above recursive formula, the final ELDC, $\bar{t}_N(P_L)$, includes the forced outage effects of all units and consequently contains additional information about the system. Referring to Figure F-3, T^* is number of days that the equivalent load equals or exceeds the system capacity, commonly known as the LOLP for the generating system. That is,

$$\text{LOLP} = \bar{t}_N(b_N) = T^*$$

The shaded area shown in Figure F-3, defined by $\bar{t}_N(P_L)$ and the total system capacity, b_N , represents the "expected unserved energy" (EUE),

$$\text{EUE} = \int_{b_N}^{\infty} \bar{t}_N(P_L) dP_L$$

Siting Evaluation Method

Alternate sites are assessed by listing and weighting according to importance all the considerations. The merit of each site with respect to each consideration is specified by assigning a score between 1 and 5--the higher the score, the greater the merit. The weighting value is then multiplied by the score to form a weighted score. The alternative sites are then compared by summing weighted scores to form a measure of "site quality" as shown below.

Criteria	Weighting	Site A		Site B	
		Score	Weighted Score	Score	Weighted Score
Cooling System Development					
a. Water Availability During Low Flow	3	1	3	5	15
b. Thermal Effects	3	5	15	5	15
c. Reduction of Stream Flow	3	0	0	0	0
d. System Costs	4	2	8	2	8
Environmental Impact					
a. Endangered Species	3	5	15	5	15
b. Existing Aquatic Recreation	1	5	5	5	5
c. Existing Terrestrial Recreation	1	5	5	5	5
d. Potential Aquatic Recreation	2	5	10	5	10
e. Potential Terrestrial Recreation	2	5	10	5	10
f. Water Shortage Area	3	5	15	5	15
g. Pollution	2	5	10	5	10
h. Minerals	1	5	5	5	5
Transmission					
a. Proximity and Capability	5	3	15	2	10
b. Penalties	4	2	8	4	16
Flood Hydrology	2	1	2	1	2
Accessibility					
a. To Rail	1	1	1	1	1
b. To Highway	1	3	3	3	3
Population Density	2	5	10	5	10
Other Considerations					
a. Earthwork	1	1	1	1	1
b. Seismology	1	2.5	2.5	2.5	2.5
c. Relocation	1	3	3	3	3
d. Land Holdings	3	2	6	2	6
Meteorology	2	3	6	3	6
Site Quality (Total)			158.5		173.5

Figure F-3. Equivalent load duration curves (ELDC) for last two units to be loaded

APPENDIX H

Description of a Financial Model [20]

The financial model described provides a means for forecasting the financial and operating characteristics of an electric utility company (or industry) for 20 years. It was originally developed for a company providing gas and steam service as well as electricity. When revised for industry calculations, only electric service, with its associated costs and revenues, was considered. Included in the output for each of the 20 forecast years are: (1) a statement of electric operations; (2) an income statement; i.e., statement of all operations; (3) a balance sheet; (4) a source and application of funds statement; (5) a capitalization statement; (6) a balance sheet items statement which lists certain details of the plant and depreciation accounts; and (7) a statement of sales and output statistics.

The model programming is segmented into three routines which calculate: (1) sales and revenue statistics; (2) plant, depreciation and financing; and (3) operating expense and income items. Information is transferred from routine to routine within a given year, and from year to year. Within a given year an iterative procedure is employed to move from an initial estimate of tariffs to the tariffs necessary to achieve any desired return on common equity.

The versatility of the model is exemplified by its treatment of capital additions. The plant and depreciation routine accepts capital additions input in the form of service date and total direct cost for each project. Length of construction period and distribution of construction expenditures over the construction period can be specified separately for each project. This allows the user to establish different construction periods for nuclear plants than for fossil steam plants, for example. It also permits construction expenditures to be spread evenly over the construction period or to be concentrated more heavily in the middle years of the construction period according to the user's best estimate of how expenditures will actually be sequenced.

The Model calculates and cumulates allowance for construction funds on each project throughout its construction period, and transfers the accumulated amount to the plant account along with the direct cost when the plant goes into service. Once in service, the plant addition is depreciated at a rate specified in the input. Different rates can be applied to nuclear generation; to distribution; to fossil steam generation; etc. Both straight line and double declining balance tax depreciation calculations are made.

It will be noted that the industry version of the model permits breaking tax deferrals into two segments, one of which can be normalized and the other "flowed-through." The proportionate size of the two segments can be varied from year to year.

APPENDICES
OF
University of Michigan

APPENDIX A

Reliability Simulation for LOLP

The computation of a power generation system's loss of load probability (LOLP) is grounded convolution mathematics. The following material covers basic technique for LOLP simulation; for more detailed exposure the reader may consult ([4], [26]).

The LOLP for any operating period (i.e., average period risk) is the weighted sum of subperiod LOLP's. If an operating period is decomposed into M subperiods then

$$\text{Period LOLP} = \sum_{m=1}^M (\text{LOLP}_m \cdot T_m) / \sum_{m=1}^M T_m \quad (\text{A.1})$$

where LOLP_m and T_m are the m-th subperiod's LOLP

and time duration, respectively. The probability laws on load and available capacity are necessary inputs for computing a subperiod's LOLP.

Load Model: For each subperiod, the demand is modeled by a load duration curve (LDC); see Figure A.1. By normalizing time the LDC can be used to define the percent of time within the subperiod that demand will be less than or equal to any given level. Accordingly, the curve provides an artifice for interpreting demand as a random variable where the following notation should be self explanatory.

- L , demand
- $\bar{L}$, maximum demand
- $\underline{L}$, minimum demand
- $F_L(x)$, the probability that $L \leq x$ (see Figure A.2)
- $f_L(x)$, the probability that $x \leq L \leq x + dx$.

Figure A.1

A Subperiod Load Duration Curve

Figure A.2

Subperiod's Load Probability Distribution

Available Capacity: The power system's available capacity, AC is modeled as the sum of independent random variables where each random variable is available capacity of a discrete generation sou

$$AC = \sum_{n=1}^N AC_n \quad (A.2)$$

where AC_n denotes available capacity for the n -th source. For each source, available capacity is modeled as a multiple state equilibrium Markov process,

$$AC_n = C_{n,j} \text{ with probability } a_{n,j} \text{ for } j = 1, \dots, J \quad (A.3)$$

where J denotes the number of possible states and $\sum a_{n,j} = 1$. Usually a two state model is assumed where $c_{n,1}$ is zero with a probability equal to the plant's expected forced outage rate and $c_{n,2}$ is the plant's rated capacity.

Equivalent Load Approach to LOLP Simulation: The LOLP for an arbitrary subperiod can be defined as

$$LOLP = \int_{\underline{L}}^{\bar{L}} \text{Prob} \{AC \leq x\} f_L(x) dx \quad (A.4)$$

However, by introducing a simple transformation on the random variable, L , then convolution techniques can be efficiently applied to compute LOLP. Defining equivalent load, EL as

$$EL = L + \sum_{n=1}^N (C_n - AC_n) \quad (A.5)$$

then $F_{EL}(x)$ denotes the probability that $EL \leq x$ and the subperiod LOLP is given by,

$$LOLP = 1 - F_{EL}\left(\sum_{n=1}^N C_n\right) \quad (A.6)$$

The distribution function $F_{EL}(\cdot)$ is computed by performing an N -th order discrete convolution. The process is executed recursively as follows. If,

$$F_1(x) \equiv \sum_{j=1}^J F_L(x - AC_{1,j} + AC_{1,j}) \cdot a_{1,j} \quad (A.7)$$

For $0 \leq x \leq \bar{L} + C_{1,j}$ then

$$F_{i+1}(x) = \quad (A.8)$$

$$\sum_{j=1}^J F_i(x - AC_{i+1,J} + AC_{i+1,j}) \cdot a_{i+1,j}$$

for

$$0 \leq x \leq \bar{L} + \sum_{n=1}^{i+1} C_{n,j}$$

and the process applies for $i = 2, \dots, N$ with the distribution function $F_N(\cdot) = F_{EL}(\cdot)$.

APPENDIX B

Capital Cost Simulation

Levelized cash flow modeling has normally been used to simulate capital cost cash flow for power generation planning. Given the data the process is straightforward. If

- GPIC is the gross plant investment cost including interest during construction.
- DEP is annual depreciation given as a % of GPIC.
- T&I is annual taxes and insurance given as a % of GPIC and,
- RR is the utility's cost of capital or required rate of return as a %

then the levelized fixed charge rate, LFC is

$$LFC(\%) = DEP + T\&I + RR \quad (B.1)$$

and the plant's uniform annual capital cost is

$$CC = \frac{LFC(\%)}{100.0} \cdot GPIC \quad (B.2)$$

where the cash flow occurs over the plant's operating life. In reality, a plant's capital cost cash flow exists over a larger timeframe (i.e., construction period and operating life) and within this timeframe the charges are not uniform. During the construction period investment is steadily increasing and during operation the investment gradually decreases over time; accordingly the annual capital charges associated with this investment will change (see Figure B.1). Normalized time varying cash flow approximation models can be estimated for different types of generation and cash flow is given by,

$$CC_t = NCC_t \cdot GPIC \text{ for } t = t_c, \dots, t_f \quad (B.3)$$

where t_c and t_f denote respectively the time construction begins and the time operation ends

and where NCC_t is the estimated fixed charge rate in year t , given as a percent of the gross plant investment cost.

Figure B.1

Capital Cost Cash Flow Illustration

APPENDIX C

Basic Production Cost Simulation

Production costing simulators are designed to estimate the production costs, energy output and operating hours of each plant in the system. Reports are made for each operating year over the planning horizon.

Production simulation can be quite complicated as one tries to model the effects of forced outage, multiple plant heat rates, usage level constraints, and energy storage. The material to follow describes a basic framework for production simulation using weekly load duration curves; the reader can consult ([15], [16], [22], [26]) for discussion on more detailed simulation logic. Assume that each operating period is decomposed into weekly subperiods and, also, assume that scheduled available plants remain fixed within

each subperiod. For each subperiod one has

- a weekly load duration curve (LDC)
- a set of plants scheduled to be available for production
- a priority sequence for loading plants (or discrete blocks of plant capacity) against the LDC
- usage level constraints to be observed in plant loading.

The priority sequence for plant loading is designed to minimize production costs within each subperiod.

Assume the system is composed of conventional hydro, pumped hydro and thermal units. Assume each plant has a single operating cost rate (i.e., constant heat rate) and assume that only conventional and pumped hydro units have weekly energy production constraints. Then the model for plant loading proceeds by:

- (1) Loading all must run hydro units so as to uniformly reduce load over the week.
- (2) Using the residual LDC from (1), load all remaining conventional hydro units at their level of expected available capacity so as to reduce peak demand while observing weekly MWH energy limits.
- (3) Using the residual LDC from (2) load pumped hydro units so as to levelize load. This requires an iterative process where supply is loaded at the level of expected available capacity so as to further reduce peak or intermediate loads while observing MWH energy limitations. Then energy renewal is satisfied by increasing base load. Pumped hydro utilization is optimized when its supply contribution is maximized while insuring that the marginal cost for energy renewal is less than the marginal thermal energy cost for replacing pumped hydro supply.
- (4) Using the residual LDC from pumped hydro loading then the modeling structure for LOLP (introduced in Appendix A) may be applied to compute the expected energy output and operating hours for the set of thermal units. If there are N thermal units where each unit has two availability states (i.e., either zero or full capacity) and if loading priority implies the k -th unit is loaded only after the first $k-1$ units are fully loaded then for the k -th unit,

Expected Production (MWH) =

$$a_k \cdot T \cdot \int_{z_{k-1}}^{z_k} F_{k-1}(x) dx \quad (C.1)$$

and

Expected Operation Hours =

$$a_k \cdot T \cdot (1 - F_{k-1}(z_{k-1})) \quad (C.2)$$

for $k = 1, \dots, N$ where

- a_k , expected availability rate of k -th unit.
- $T = 168$ hrs., a week's duration.
- z_k , sum of rated capacities for the first k units in the priority sequence.
- $F_k(\cdot)$, the probability distribution function for equivalent load based on the first k thermal units in the priority sequence.

Computation of production costs are determined by applying a unit's cost rate for fuel to expected production and the cost rates for O&M and start up to the expected operating hours.

APPENDIX D

Target Plant Mix Model

Purpose: Determine the least-cost mix for additions in generation capacity for each year over the planning horizon.

Model Assumptions

- The present mix of available generation capacity is optimally configured for existing demand; existing capacity will remain intact over the planning horizon.
- The growth in demand for any year can be modeled by a single weekly load duration curve which repeats itself throughout the year. Load growth remains stationary over the planning horizon (i.e., although the absolute values of demand growth can change over time, the load shape for each year's demand growth remains constant over time).
- The set of available generation technologies remain fixed over the planning horizon.

- For every generation technology there is a continuous set of available plant sizes.
- A plant's power capacity remains constant over each year and is given as the expected available capacity (i.e., a uniform average derating for forced outage, preventive maintenance and seasonal fluctuations is assumed). When a plant is installed it always operates at its level of expected available capacity.
- For energy limited generation types, the limit can be specified in hours of allowable weekly operation and the limit is assumed to remain constant over time.

Model Inputs

- G , number of available generation plant types.
- $(FC_g, g = 1, \dots, G)$, annual fixed charge in \$/MW for each plant type; includes a plant's capital costs and any fixed operating costs.
- $(VC_g, g = 1, \dots, G)$, variable production cost in \$/MWH for each plant type.
- L , number of distinct duration levels in the weekly duration curve for each year's increased demand.
- $(d_{\ell,t}, \ell = 1, \dots, L)$, demand increase (in MW) in year t for each of the L components of the load duration curve; note the stationarity assumption on demand implies that $[d_{\ell,t}/\sum_{t \in L} d_{\ell,t}]$ remains constant over all t .
- $(A_g, g = 1, \dots, G)$, capacity derating factor for each generation type; maps installed capacity over to expected available capacity.
- $(E_g, g = 1, \dots, G)$ upper limit on the weekly hours of operation for each generation class; for plant types which are not energy limited then set limit to 168 hours.

Synthesis Method: The assumptions listed above yield a generation expansion decision which is free of dynamic complications. Average plant costs can be projected onto a simple load duration curve to define a target generation mix.

- For each plant type compute the total plant cost per MWH as a function of the number of weekly hours of operation; for the g -th plant type.

Total Average Cost =

$$TAC_g = VC_g + \left(\frac{FC_g}{52A_g} \right) / x \quad (D.1)$$

where x is hours of weekly operation and $0 < x \leq E_g$.

- By examining all cost functions over their appropriate range of feasible x -values, one can define for each generation type a corresponding interval of load durations for which the plant type is the least-cost power supply source (see Figure D.1).
- Using the optimal matching between plant types and duration levels and using the weekly load duration curve for increased demand in any year, then a determination of capacity additions for each type is straightforward. The capacity additions define a generation mix which in turn can be used as a target in forming expansion plans over the planning horizon (see Figures D.2 and D.3 for illustration).

LEAST COST MATCHING	
Type	Duration Level Interval
1	$0 < x \leq 40$
2	None
3	$40 < x \leq 80$
4	$80 < x \leq 168$

Figure D.1

Illustration of Least Cost Matching
by Generation Type/Duration Level

Figure D.2

Illustrative Weekly Load Duration Curve

Plant Type/Duration Level Matching (Figure D.1)
and Load Duration Curve (Figure D.2)

Least Cost Expansion

d_5 MW of Type 1
0 MW of Type 2
 $d_4 + d_3$ MW of Type 3
 $d_2 + d_1$ MW of Type 4

Target Generation Mix

Type 1 = $d_5 / \sum d_k$
Type 3 = $(d_4 + d_3) / \sum d_k$
Type 4 = $(d_2 + d_1) / \sum d_k$

Figure D.3

Target Mix Determination

APPENDIX E

Mathematical Programming Model

Purpose: The mathematical programming model, described below, determines for each year over a planning horizon what types and sizes of generating plants should be constructed so as to minimize total discounted cost while meeting reliably (under an approximated LOLP measure) the system's forecasted demands for electricity. Unlike the static framework of the target mix model, relative variations over time in power supply costs and power plant operations can be accounted for with this model. The investment and production modeling are rigorously united within the optimization logic and, as a consequence, the mathematical program is large scale.

Model Assumptions

- Power plant costs can be represented through two components, a fixed charge (\$) incurred by investment and a single variable cost rate (\$/MWH) which applies directly to a plant's total output.
- Plants with similar production costs and operating constraints may be aggregated into classes with production modeling existing only at the class level.
- Although variations in the supply/demand patterns between operating periods can be modeled, the capability is limited and temporal aggregation is applied. Specifically, it is assumed that each year's operation can be modeled via a small set of operating weeks where each week is assumed to repeat a given number of times within the year.

Model Formulation

The index parameters for the model are:

- T - number of years in the planning horizon ($t = 1, \dots, T$).
- I - number of distinct operating weeks used per year to model seasonal variations in demand and available capacity ($i = 1, \dots, I$).
- K - number of different demand levels used in modeling each weekly demand pattern ($k = 1, \dots, K$).
- J - number of thermal generation classes ($j = 1, \dots, J$); plants aggregated within a thermal class are similar in terms of their operating cost rates and usage level constraints.
- H - number of conventional hydro generation classes ($h = 1, \dots, H$); plants in these classes have no variable operating costs and within a class plants are similar with respect to their ratio of weekly energy capacity (megawatt hours) to power capacity (megawatts).
- P - number of pumped hydro generation classes ($p = 1, \dots, P$); plants in these classes have no explicit variable operating costs and within a class plants are similar both with respect to pond size and pumping efficiency.
- G - total number of generating classes; classes are ordered such that $g = 1, \dots, J, J + 1, \dots, J + H + 1, \dots, J + H + P = G$.
- G_u - number of generating classes with a usage level (i.e., capacity factor)

production constraint.

$M(t, g)$ - number of alternative investment projects available in year t from the g -th class ($m = 1, \dots, M(t, g)$).

Decision Variables

$Y(t, g, m)$ is the number of projects of the m -th type to be installed from class g in the year t . When the future additions to a class entail a single plant size and the size is small, then $M(t, g) = 1$ and $Y(t, g, m)$ is a continuous variable; otherwise each investment alternative refers to a specific number of plants of a given size and $Y(t, g, m)$ is a binary decision variable. $X_g(t, i, g, k)$ is the production level in megawatts of the g -th class for the k -th demand in the i -th operating week of year t . $X_c(t, i, p, k)$ is the demand level in megawatts being placed on the system by the p -th pumped hydro generating class (operating in a consumption mode) during the k -th demand in the i -th operating week of year t .

Objective Function

The objective is to minimize the total discounted cost which equals:

$$\sum_{t=1}^T \sum_{g=1}^G \sum_{m=1}^{M(t,g)} IC(t,g,m) \cdot Y(t,g,m) + \sum_{t=1}^T \sum_{i=1}^I \sum_{g=1}^G \sum_{k=1}^K F(i) \cdot DUR(k) \cdot OC(t,g) \cdot X_g(t,i,g,k) \quad (E.1)$$

where

- $IC(t, g, m)$ is the discounted investment cost of one unit of the m -th type project from class g in year t (including gross investment, insurance, property taxes, and all other costs which are independent of a plant's actual utilization);
- $OC(t, g)$ is the discounted operating cost (\$/MWH) for the g -th class in year t ;
- $F(i)$ is the frequency parameter defining the number of times in the year the i -th operating week occurs, and
- $DUR(k)$ is the duration parameter defining how many hours in the week the k -th demand level occurs.

Constraints on Investment Variables

If the g -th class is discrete, then the multiple choice constraint:

$$\sum_{m=1}^{M(t,g)} Y(t,g,m) \leq 1 \quad (E.2)$$

must be satisfied for $t = 1, \dots, T$. This constraint enforces the standard practice of not installing different plant sizes from the same generation class in any single year.

The model constraints which most complicate the optimization methodology are the system reliability constraints. For each year over the planning horizon, the probability that annual peak demand will not be satisfied must be less than or equal to some specified risk level. The exact constraint for the t -th year is given by

$$\text{Prob} \{ \beta_t C_t \leq d_t \} \leq R^*, \quad (E.3)$$

where C_t is a random variable which represents the total available capacity at the time of the peak demand when there is no derating for preventive maintenance or seasonal conditions; the factor β_t is a model input which attenuates the total capacity in accordance with seasonal inefficiencies and the percent of system capacity scheduled for preventive maintenance during the period of peak demand. The forecast for peak demand, d_t , is customarily modeled as a Normal random variable with mean $\bar{d}_t$ and variance σ_t^2 . R^* denotes the maximum allowable risk for the system. The random variable C_t is modeled as a weighted sum of independent Bernoulli random variables where each weighting coefficient equals a plant's nameplate capacity and the success probability for the associated Bernoulli random variable is one minus the plant's estimated forced outage rate.

Approximating the distribution function of $\beta_t C_t - d_t$ as Normal, then the chance constraint, (E.3) can be approximated by an equivalent deterministic constraint of the form

$$\left[\beta_t E(C_t) - \bar{d}_t \right] + S(R^*) \left[\beta_t^2 \text{Var}(C_t) + \sigma_t^2 \right]^{1/2} \geq 0 \quad (E.4)$$

where $S(R^*)$ is the fractile of order R^* of the standardized variation of $(\beta_t C_t - d_t)$. $E(C_t)$ and $\text{Var}(C_t)$ are the mean and variance of C_t . These statistics can be expressed in terms of the decision variables by:

$$E(C_t) = \sum_{\tau=1}^t \sum_{g=1}^G \sum_{m=1}^{M(\tau,g)} EC(t,\tau,g,m) \cdot Y(\tau,g,m) + \sum_{g=1}^G IEC(t,g) \quad (E.5)$$

$$\text{Var}(C_t) = \sum_{\tau=1}^t \sum_{g=1}^G \sum_{m=1}^{M(\tau,g)} VC(t,\tau,g,m) \cdot Y(\tau,g,m) + \sum_{g=1}^G IVC(t,g) \quad (E.6)$$

where $EC(t, \tau, g, m)$ and $VC(t, \tau, g, m)$ denote the mean and variance of the maximum rated capacity from the τ, g, m -th project in year t and where $IEC(t, g)$ and $IVC(t, g)$ denote the mean and variance of the maximum rated capacity from the g -th class and in year t prior to making any plant additions.

Constraints on Production Decisions

The fundamental time unit in the production model is a week. For each year, a small number of distinct weekly patterns - at most three or four - is sufficient to represent the seasonal variations in supply and demand. For the entire planning horizon there are $T \cdot I$ distinct weekly production allocation subproblems and for each subproblem there exists four distinct subsets of constraints. Considering the i -th week of the t -th year, one first has K demand constraints

$$\sum_{g=1}^G X_g(t, i, g, k) - \sum_{p=1}^P X_c(t, i, p, k) \geq DEM(t, i, k) \quad (E.7)$$

where $k = 1, \dots, K$ and $DEM(t, i, k)$ denotes the level of the k -th demand in the i -th week of year t . Secondly, there are $(G + P)K$ power capacity constraints

$$X_g(t, i, g, k) \leq TEC(t, i, g), \quad (E.8)$$

$$X_c(t, i, p, k) \leq TEC(t, i, J + H + p), \quad (E.9)$$

where $g = 1, \dots, G$; $p = 1, \dots, P$; $k = 1, \dots, K$. The term $TEC(t, i, g)$ denotes the total expected available capacity for class g in the i -th week of year t .

Also, in each of the $T \cdot I$ weekly allocation subproblems, there are G_u usage level constraints of the form

$$\sum_{k=1}^K DUR(k) \cdot X_g(t, i, g, k) \geq U(g) \cdot TEC(t, i, g), \quad (E.10)$$

where $U(g)$ is the usage level multiplier which converts available power capacity in megawatts to either a minimum or maximum weekly energy level in megawatt hours for that class. Finally, there are P pumped hydro renewal constraints of the form

$$\sum_{k=1}^K [X_g(t, i, J + H + p, k) - E(p) \cdot X_c(t, i, p, k)] \cdot DUR(k) \leq 0 \quad (E.11)$$

for $p = 1, \dots, P$, where $E(p)$ denotes the pumping efficiency of the p -th pumped hydro class. This constraint insures that at the end of a week the water level in a reservoir will equal the level that existed at the beginning of the week.

Solution Technique

The mathematical model formulated in the previous section has a special structure which is illustrated below

$$\text{Min } \underline{c}' \underline{y} + \sum_{t=1}^T \sum_{i=1}^I \underline{h}_{ti}' \underline{x}_{ti} \quad (E.12)$$

subject to

$$\underline{y} \in S \quad (E.13)$$

$$A \underline{x}_{ti} + B_{ti} \underline{y} \geq \underline{b}_{ti} \quad (E.14)$$

$$\underline{y} \geq \underline{0}; \underline{x}_{ti} \geq \underline{0} \text{ for } i=1, \dots, I; t=1, \dots, T. \quad (E.15)$$

where $\underline{y}$ and $\underline{c}$ denote, respectively, vectors of investment decision variables and investment cost coefficients. The vectors $\underline{x}_{ti}$ and $\underline{h}_{ti}$ are, respectively, the production decision variables and the production cost coefficients that are associated with the ti -th production subproblem. The set S denotes all investment plans feasible with respect to the binary restrictions, the multiple choice constraints (E.2), and the set of nonlinear system reliability constraints (E.4). The constraints of (E.14) denote the operating relationships for the ti -th production subproblem. The $T \cdot I$ sets of these constraints are coupled through the investment decisions $\underline{y}$ and they make the mathematical program quite large. In a recent and typical application, the GPP formulation gave rise to a model with 450 binary investment decision variables, 75 continuous investment decision variables and 5700 continuous production decision variables. There were 75 multiple choice constraints on the binary decision variables, 25 quadratic reliability constraints on investment decision and 6250 constraints on production. Large scale optimization techniques are necessary for efficient solution of these problems; the interested reader is referred to ([19]) for more information.

APPENDICES
OF
Systems Control, Inc.

Scope

WASP is designed to find the optimal generation expansion policy for an electric utility system using dynamic programming and probabilistic simulation. The program evolved from the SAGE expansion program at the Tennessee Valley Authority.

APPENDIX A
WASP - WIEN AUTOMATIC SYSTEM PLANNING PACKAGE

R.T. Jenkins Tennessee Valley Authority
D.S. Joy Oak Ridge National Laboratory

Featured in the planning package are the following capabilities:

- User supplied life of new generation projects
- Pumped storage and hydroelectric
- Probabilistic simulation including forced outages and scheduled maintenance
- Binding constraints
- Separation of financial calculations into domestic and foreign accounts
- Study period of up to 30 years in length
- Modular configuration allows flexible data manipulation

Objective

The objective function is the present worth discounted summation of capital costs, operating costs and salvage value. For capital expenditures, the escalation rate of construction cost and discount rate of time preference can be combined in the formula

$$Q_{kj} = \frac{(1 + m_k)^p}{(1 + i_k)^n}$$

where Q_{kj} = Combined present worth and escalation factor for expansion unit k in study year j

m_k = Escalation rate of k^{th} candidate

i_k = Present worth discount rate for k^{th} candidate

n = Number of years from present-worth base year

p = Number of years from escalation base year

In the case of a new unit, the capital cost is considered to be paid at the initial point of a specific stage (or year) as is the capacity increase. A "weighting factor" to reflect preferences with regard to foreign capital is included in the capital expenditure calculation.

$$C_j = \sum_k \left[Q_{L_{kj}} \cdot IL_k + FF_j \cdot Q_{F_{kj}} \cdot IF_k \right] \cdot MWC_k \cdot N_k \cdot 10^3$$

C_j = Present worth of capital expenditure for year j

k_j = Index number of expansion unit

$Q_{L_{kj}}$ = Local capital present-worth and escalation factor

$Q_{F_{kj}}$ = Foreign capital present-worth and escalation factor

IL_k = Base year local capital cost

IF_k = Base year foreign capital cost

FF_j = Foreign capital "weighting factor"

MWC_k = Megawatt capacity of k^{th} expansion candidate

N_k = Number of units added of type k

Credit to the objective function from salvage value is represented by the discounted residual capital expenditure

$$R_j = \sum_k P_{knyr} S_{kj}$$

where R_j = Credit for all unit additions in year j

$P_{knyr} = (1+i_k)^{-nyr}$

nyr = Number of years from P.W. base year to end of study

S_{kj} = Computed salvage value for unit(s) k . (see below)

If C_{kj} = Undiscounted capital cost for expansion candidate k escalated to year j ,

$$then \quad C_{kj} = \left[(1+m_k)^p IL_k + FF_j (1+m_k)^p IF_k \right] \cdot MWC_k \cdot N_k \cdot 10^3$$

and $S_{kj} = \left[1 - \frac{y_k}{L_k} \right] C_{kj}$ (Straight Line Depreciation)

where L_k = Economic life in years of candidate

y_k = Study life portion of economic life

$$or \quad S_{kj} = \left[1 - \frac{1 - (1+i_k)^{-L_k + y_k}}{1 - (1+i_k)^{-L_k}} \right] C_{kj}$$

(Sinking Fund Depreciation).

Operating costs due to fuel expenditures are assumed to be paid at the mid point of each stage. Then the combined present-worth and escalation cost factor for fuel ℓ in year j is:

$$Q_{\ell j} = \frac{(1+m_{\ell})^n}{(1+i_{\ell})^{m+\frac{1}{2}}}$$

Hence operating cost for year j is

$$Q_j = \sum_{\ell} Q_{\ell j} (CST_{\ell} + NFCST_{\ell}) + QF_{\ell j} \cdot FF_j \cdot FCST_{\ell}$$

where CST_{ℓ} = Local fuel expenditure for fuel type 1 (See Production Decisions)

$FCST_{\ell}$ = Foreign fuel expenditure

$NFCST_{\ell}$ = Local nonfuel operating expenditures

Finally the complete objective is

$$L(X) = \sum_{j=1}^t C_j - R_j + Q_j$$

Constraints

Constraints in dynamic programming have a non-pejorative effect and actually make computation time feasible. A particular state configuration must have a minimum and maximum reserve requirement; a greatly expanded system is not economic. Thus

$$SCAP \geq (1.0 + (RSV)_{\min}) \cdot MWPEAK$$

$$SCAP \leq (1.0 + (RSV)_{\max}) \cdot MWPEAK$$

where $SCAP$ = Capacity of state (MW)

$(RSV)_{\min}$ = Minimum reserve margin

$(RSV)_{\max}$ = Maximum reserve margin

Another means of reducing the number of alternatives is to place a restriction on the number of units for each project considered, then

$$(MIN)_i \leq N_i \leq (MAX)_i$$

where $(MIN)_i$ = Minimum number of units to be considered

N_i = Number of units of expansion candidate i

$(MAX)_i$ = Maximum number of units to be considered

Additionally, the actual reliability of the generating system is computed in the simulation subprogram and states which do not meet the critical value are rejected. User-controlled constraints on state capacity and alternative selection may be modified without concomitant loss of state simulation data when it is found that the constraint is binding for the optimal solution.

Method of Solution

The WASP package is composed of six program modules; each is executed separately and data may be checked and corrected before implementing the next step.

The Fixed System Program (FIXSYS) describes the state of the initial existing power system and includes data on the number of units of each type, minimum and maximum operating capacities, heat rates, fuel type and cost, forced-outage rates and maintenance requirements. Precommitted units and retirement rates are also specified.

VARSYS (The Variable System Program) defines the unit types to be considered in expansion plans. This may include pumped storage and/or hydroelectric projects. Data requirements correspond to the inputs of FIXSYS.

Generation requirements in each stage of the study are defined by the Load Description Program (LOADSY) which develops the load duration curve for each period within the year from the load data.

The Expansion Configuration Generator Program (CONGEN) allows the system planner to direct the focus of this study to the area of most economic concern by user-controlled constraints (see Constraints).

Simulation of the configuration and computation of the operating cost is provided by MERSIM (Merge and Simulate Program). A probabilistic model is used to calculate unit loadings, system cost (in local and foreign exchange), probability of not being able to meet the system load and the probable amount of unserved energy.

The optimal expansion policy and economic calculation of fuel escalation prices, penalty on foreign expenditures and present-worth is determined by the Optimization Program (DYNPRO). States which are feasible are those which have a lower LOLP than the critical value. Constraints used in CONGEN to expedite the procedure which are binding in the optimal solution are identified by DYNPRO.

Production Decisions

The shape of the load duration curve is represented as a fifth order polynomial

$$y = \sum_{j=0}^5 a_j x^j$$

where y = fraction of peak load

x = fraction of time

The coefficients ($a_0, \dots, a_5$) determine the shape and must be modified if a change in shape is forecasted. Peak loads are specified for each stage in the study period; fractions of the annual peak are input. Then the year is subdivided into periods (at most 12). For use by the simulation program, the curve is discretized into a partition with mesh DM. The following must hold:

$$DM > \frac{(ICAP)_{\max}}{590}$$

where $(ICAP)_{\max}$ is the maximum installed capacity.

The number of points in the partition may be estimated by:

$$N = \frac{ICAP}{DM}$$

In practice 100-350 discrete points are recommended.

Prior to production costing and simulation an estimated maintenance schedule must be formulated to determine equipment availability. The procedure outlined here classifies generation units by capacity magnitude and allocates time for maintenance for the largest class when reserves are greatest and correspondingly for the smallest class when reserves are least. The minimum reserve for each period:

$$MNRSV_i = INSTCP_i - MAXLD_i$$

where $MNRSV_i$ = Minimum reserve in period i
 $INSTCP_i$ = Installed capacity in period i
 $MAXLD_i$ = Maximum system load in period i

If $PSMAIN_i$ is the previously scheduled maintenance in period i then available maintenance space for that period $MAINSP_i = MNRSV_i - PSMAIN_i$.

Each class has total maintenance requirement

$$MWDAYS = \sum_i (MWC)_i \cdot (MAINT)_i \cdot (NOSETS)_i$$

where $(MWC)_i$ = Actual capacity of unit i
 $(MAINT)_i$ = Maintenance requirement for unit i
 $(NOSETS)_i$ = Number of units i

The amount of maintenance that can be performed by removal of a specific capacity for the entire period (maintenance block)

$$MAINBK = (MAINCL) \cdot (T_p)$$

$$MAINCL = \text{Capacity of maintenance class}$$

$$T_p = \text{Length of period in days}$$

$NO = \frac{MWDAYS}{MAINBK}$ blocks are required for each maintenance class and the blocks are sequentially assigned to this period with the largest maintenance space ($MAINSP_i$). Each class is considered in order starting with the one of greatest magnitude.

An example is pictured in the accompanying diagram in which the first two maintenance blocks were scheduled during the first period, the third block to the second period and the remaining fractional block to the fourth period. This illustrates consideration of a fractional block where an estimated interpolated capacity $MCLL = \frac{REMAIN}{T_p}$ allows the maintenance to extend over the entire period.

$$REMAIN = MWDAYS - [NO] \cdot MAINBK$$

Once all the classes have been provided with maintenance schedules the availability rate for each unit is calculated as follows:

$$P_i = \frac{N_i}{NO}$$

$$P_i = \text{Probability of performing maintenance for class in period } i$$

$$N_i = \text{Number of maintenance blocks scheduled in period } i$$

Thus expected outage rate

$$(Pm)_i = \frac{(MAINT)_i \cdot P_i}{T_p}$$

whereupon the expected availability rate for each unit

$$A_i = (1 - Pm_i) (1 - FOR)$$

Simulation of the effect of random outages is expressed by means of the equivalent load duration curve for each period:

$$EL_i(\cdot) = P_i EL_{i-1}(\cdot) + q_i EL_{i-1}(\cdot - MW_i)$$

$$\text{where } P_i + q_i = 1$$

$$P_i = \text{Availability rate for unit } i \text{ during period (see above)}$$

$$\text{and } EL_0 = \text{Original load duration curve}$$

Expected generation for unit i is

$$E_i = P_i T \int \frac{\sum_{j=1}^i MW_j}{\sum_{j=1}^{i-1} MW_j} EL_{i-1}(x) dx.$$

the LOLP is P^* and expected unserved energy

$$U = T \int \frac{\sum_{j=1}^i MW_j}{\sum_{j=1}^{i-1} MW_j} EL_i(x) dx.$$

in the following diagram:

In the previous discussion, it was assumed that units would be completely loaded in turn; a more realistic assumption is that the loading is divided into base load and peak load blocks. Generally, base load and cycling units are defined with two blocks and peaking units only have a load following component. A heat rate is specified for the base block as is the average incremental heat rate for the load following block.

Hydroelectric projects must be combined into a single unit whose capacity is the sum of each individual unit capacity as is the energy of the entire project. As in the thermal units, capacity can be divided into two blocks; the base block is placed in first position in the loading order and the residual capacity is used for peak shaving. Energy generation is limited by water supply and reservoir constraints. In addition, an emergency hydroelectric category may be defined. This is used to increase system reliability by "backing up" units out-of-service. A penalty cost is associated with this type of operation. Capacity multipliers are defined to reflect varying distribution of energy and capacity availability among periods within the year.

As in the case with hydroelectric generation,

the capacities and reservoir limits are combined for all pumped-storage units to yield a combined unit. The cycle efficiency is the weighted average of the individual efficiencies.

Plant types are indexed by five types:

Nuclear

Fossil-fired

Hydroelectric

Pumped-storage

Emergency hydroelectric

Moreover, the fossil-fueled plant can be divided into four subgroups with their own unique fuel requirements.

Costs are obtained from the heat rates:

$$FLHTRT = \frac{(BHRT)(MWB) + (CRMHRT)(MWC - MWB)}{MWC}$$

BHRT = Heat rate for base block

MWB = Capacity for base block

CRMHRT = Average, incremental heat rate for load following portion

FLHTRT = Full load heat rate

Then operating cost for fuel,

$$OC = 10^{-5} (HR) (FC)$$

HR = Appropriate heat rate

FC = Appropriate fuel cost

(can be calculated for foreign or local expenditure).

Non fuel expenditure for each unit is

$$NFCST = OMA \left(\frac{12}{NPER} \right) \cdot MNC \cdot NOSETS \cdot 10^3 \\ + OMB \cdot (ENGB + ENGP) \cdot 10^3$$

where NFCST = Non fuel expenditure for unit operation

OMA = Fixed O & M cost

NPER = Number of periods in year

NOSETS = Number of identical units

OMB = Variable operating and maintenance cost

ENGB = Expected generation of base portion of capacity

ENGP = Expected generation of peak portion of capacity

vestment Decisions

The optimization procedure (dynamic programming) finds the policy which results in a system of desired reliability with minimum discounted cash flow expenditures over the study period.

Let $D(t)$ = Decision made between stage $t-1$ and stage t

$X(t)$ = State or configuration of power system

then $X(t) = X(t-1) + D(t)$

implies $X(t) = X(0) + \sum_{j=1}^t D(j)$ where $X(0)$ is the

the initial system state.

The objective function is

$$L(X) = \sum_{j=1}^t C_j - R_j + O_j \quad (\text{see Objective})$$

To find the optimal path, the optimal path to every state in each stage is determined up to stage $j-1$ by the recursive procedure outlined here. The optimal objective costs to states at stage $j-1$ are added to the cost of attaining the state under consideration at stage j to find that state in stage $j-1$ that lies in the optimal trajectory to the state at stage j . Associated with that state in the final year of the study period which has the minimum cumulative discounted cost is the optimal trajectory which can be determined by tracing backward to the initial condition.

Limitations

In the approximation of capacity required for a fractional maintenance block, a distortion of actual capacity removed from the system is incurred. The number of maintenance classes should not exceed 7 for this reason.

Uncertainty is neglected in the load forecast and hydroelectric capacity. Also, the ability of hydroelectric power to cover forced outages is neglected in the model due to the removal of the peaking portion of the hydroelectric energy directly from the original load duration curve. The maximum

number of configurations in the Optimization Program is limited to 200 requiring the use of restrictive user imposed "tunnels" that often sharply restrict global optimality to a local region and require heuristic methods of constraint modification. The length of the study period is limited to 30 years.

Examples and Test Cases

Not available.

Performance Capability

Maximum core storage required for the WASP package is 30 K words and 120 K bytes on an IBM computer. Data may be used from previous iterations to facilitate computation time reduction.

APPENDIX B OPTGEN - OPTIMAL GENERATION EXPANSION BY DYNAMIC PROGRAMMING

Stephen T. Lee

Stone and Webster
Engineering Corporation

Scope

This program determines optimal generation expansion plans for an electric utility using dynamic programming. It has the following special features:

- Automatic computation of up to 100 near-optimal expansion plans
- Manually prepared expansion plans can be simulated using the same program to provide a consistent evaluation and comparison with the program-generated optimal plan
- Automatic selection of plant sites with their associated transmission costs
- Option to use probabilistic or deterministic production cost simulation
- Automatic truncation of non-optimal plans
- Capacity and cost adjustments to account for end effects of alternative plans

Objective

The normal practice by a privately-owned utility company in generation expansion planning is to minimize the present worth of the revenue requirement. Included in the revenue requirement is the rate of return allowed by a regulatory agency.

The objective of the program is to minimize the present worth of the annual revenue requirement over a selected period. Two periods for defining the objective function are allowed:

- (1) Simulation period only, i.e., only those years in which actual load growth and unit additions are simulated.
- (2) Simulation period plus an evaluation period of any duration. In the evaluation period, load

growth is assumed to be stopped and generating units are replaced in kind.

Revenue requirement consists of fuel costs, O&M costs, depreciation, interest payment, insurance, taxes (if any), and return on equity. A levelized fixed charge rate is used to represent the equivalent uniform annual cost of owning a particular facility. Fixed charges include those for generating facilities as well as for site-related transmission facilities.

Escalation rates can be specified for capital investment (one rate for all types), separately for three fuel types, and for all operating costs.

Only one discount rate for present worth calculation is allowed and it cannot be time-varying.

Constraints

The following constraints are considered by the program to limit the number of feasible states.

Reserve Constraints:

The reserve constraints used in the program define a minimum and a maximum percentage reserve within which feasible expansion plans are sought.

Reliability Constraint:

A reliability index is calculated for each potential state of expansion and a minimum reliability index based on the benchmark year performance is used to reject unreliable expansion plans. This constraint may be nullified in which case the minimum reserve percentage becomes the binding constraint.

The calculation of the reliability index is based on a simplified and approximate method of estimating the probability of loss of load (LOLP). For the benchmark year, the cumulative probability distribution of forced outages is computed by the usual convolution process. The LOLP based on the peak load for the benchmark year is calculated. Its value is normalized to 1.0 and is the minimum required reliability index.

The cumulative distribution of forced outages is then approximated by four log-linear segments evaluated at intervals equal to the standard deviation of the distribution. The reliability index of a future state is estimated by computing the mean and standard deviation of forced outages, expressing the reserve of that year in terms of standard deviations above the mean value of forced outages, and obtaining it from the log-linear approximations of the distribution function for the benchmark year.

Maximum Number of Units:

Each generation alternative can be restricted by a maximum number of units which are allowed to be installed during the entire expansion period.

Method of Solution

The basic problem of generation expansion is formulated as follows. Each year in the expansion period is a stage. In each year, there are many combinations of new units which form feasible states, e.g., in the first year there may be three states, one being one 900 MW nuclear unit, the second being one 600 MW coal-fired unit, and the third being three 100 MW gas turbines.

As the years progress, the number of states increases because more new capacity is needed, and there are many different combinations of the different types of units which can meet the requirement. This is the so-called "curse of dimensionality" because the computational requirement increases with the number of states, which increases roughly exponentially with the number of alternative types of units.

Without some heuristic scheme of truncating the number of states, it is impractical to solve a problem with more than three alternative types. The heuristic truncation method which allows four or even five alternatives to be run simultaneously will be described later.

Forward Dynamic Programming:

The basic algorithm of forward dynamic programming applied in the generation expansion problem will now be described. Refer to Figures 1, 2 and 4. This part of the algorithm is called forward because it proceeds from the first year to the last, in contrast to backward dynamic programming used later and shown in Figure 3 which backtracks from the last year.

Figure 4 shows an example with two types of alternatives, a 400 MW fossil unit and a 54 MW gas turbine, and a four-year expansion period, not counting the benchmark year which is denoted by the left-most circle with two zeros. In the first year, the program finds two states which result in reserves between the specified minimum and maximum and satisfy the reliability index. They are (0,4) and (1,0), indicating four gas turbines and one fossil unit, respectively.

For each state, the program simulates the production cost of the system and finds the state among all states in the previous year which, when proceeding to the present state, does not necessitate a deletion of a unit, and which results in a minimum cost incurred up to the present year. For the first year, the only feasible transition is from (0,0) and the minimum cost is just the cost incurred in the first year. This so-called cost-to-date is the total operation and production costs and the fixed charges, present-valued and cumulated up to and including the present year. Thus the state (0,4) requires a minimum of 76.3 million dollars to reach it from the beginning.

The program then proceeds to the second year and finds four feasible states, (0,10), (1,2), (1,4) and (2,0). It simulates the production costs and for each state, it looks back one year and from the two

Figure 1. Functional Block Diagram of OPTGEN

Continued in Figure 3

Figure 2. Flow Chart of Forward Dynamic Programming

Figure 3. Flow Chart of Backward DP and Output

NOTATION FOR NEW UNITS INSTALLED

(x,y) x = NO. OF 400 MW FOSSIL UNITS
y = NO. OF 54 MW GAS TURBINES

Figure 4. Generation Expansion by Dynamic Programming

previous states it determines which of them can proceed feasibly to the present state. For instance, (1,4) can come from both (0,4) and (1,0). Among these feasible prior states, the program computes the additional costs for the present and adds them respectively to the minimum costs of the prior feasible states. From these costs-to-date, it selects the minimum cost-to-date and remembers the transition from the prior state which yields the minimum. This is called the backward pointer. For example, (1,4) has a minimum cost-to-date of \$164.4 million and the backward pointer is shown as an arrow coming from (0,4). The dotted line from (1,0) shows the other feasible transition.

The program proceeds in like fashion to the last year. At this point, the minimum cost-to-date for each state in the last year is calculated and then sorted to determine the minimum cost for all feasible transitions. In the example, (2,7) is the best state in the last year and the minimum cost is \$359.4 million. To find the expansion schedule, it is only necessary to retrace the backward pointers. Thus the optimal plan is the following sequence of states: (0,0) - (1,0) - (1,2) - (2,2) - (2,7). Subtracting one state from the following state gives the unit added each year. The optimal installation schedule thus determined is listed below.

Year	Units Added 400 MW	54 MW
1	1	0
2	0	2
3	1	0
4	0	5

Derivation of 100 Best Plans:

If the objective is to find the optimal plan only, forward dynamic programming is sufficient. A plan can be traced backward from each of the terminal states with the backward pointers or solid arrows in Figure 4. This does not give too many suboptimal plans. Backward dynamic programming is used to increase the number of such plans.

In backward dynamic programming, the algorithm starts from the next-to-last year. For each state, it finds the feasible transitions to the following year and determines the transition which results in the minimum cost-to-go. The forward pointer indicates the cheapest forward transition from that state. The program then sweeps backward and repeats for all years until it reaches the beginning. In essence, it is the same as forward dynamic programming except for the reversal of direction. See Figure 3.

Since the screening process of determining whether a state satisfies the reserve and reliability criteria and the production costing have already been done in the forward algorithm, this part takes much less time. When both methods are combined as in this program, the number of suboptimal plans which are available is limited only by the storage requirement.

Many of these plans may be identical for most of the years and are simply minor variations in the last two or three years. In order to obtain the significant suboptimal plans in the output, a number equal to the number of years in the end of the period for which minor variations may be ignored, can be

specified. For each group of plans which are identical up to the specified end years, the program will print only the cheapest plan. In this way, the top 10 plans will include a lot more plans with significant variations.

Production Decisions

Two methods of production costing are available: probabilistic and deterministic. This probabilistic method is similar to that in WASP. For computation efficiency, the deterministic method is usually used.

Deterministic Production Costing:

The method uses a trapezoidal approximation of the annual plant duration curve as reported by K.L. Hicks in 1959. It was found that the actual loading of generating units based on historical data could be approximated by a trapezoid in Figure 5 whose vertical height equaled the system generation capacity, whose width equaled 8,760 hours (a year) times the maximum capacity factor of the base load units, and whose area equaled the energy demand (MWhr) for that year. The energy generated by the individual units could be approximated by horizontal strips of the trapezoid if the vertical axis was subdivided according to the rated capacities of the units arranged in order of their energy cost (heat rate x fuel cost), with the inexpensive base load units at the bottom and the peaking units on top. The resulting capacity factors fit the actual data better than the conventional method of stacking units on the load duration curve, because all units including peaking units are loaded to various degrees.

Figure 5. The Loading Trapezoid

It should be pointed out that this is a heuristic method which attempts to model the effect of random forced outages, maintenance outages and other operating peculiarities of the system on the loading of units.

The accuracy can be further improved by two calibration factors. A peaking constant which is used to increase or decrease the rated capacity of peak-

ing units in the formation of the trapezoid can be adjusted to change the loading of peaking units. Similarly, a cycling constant is specified to change the loading of cycling units.

The individual loading of all units can be fine-tuned by the use of individual maintenance factors, which derate the units in the loading triangle. The relation of the derated capacity of a unit used in the loading trapezoid to the maintenance factors is detailed in the following equation.

Derated Capacity = Rated Capacity

$$\times \left(1 - \frac{\text{Maintenance Factor}}{\text{Base Value}}\right)$$

In this fashion, the loading of a unit can be adjusted by varying the maintenance factor.

After the capacity factor of a unit is determined by the loading triangle, the energy cost is calculated by a reciprocal curve shown in Figure 6. $H_{\max}$ and H_0 are specified for each unit. $H_{\max}$ is the heat rate at maximum loading multiplied by the fuel cost. H_0 can be adjusted to obtain the correct energy cost for lower capacity factor.

Figure 6. Energy Cost vs. Unit Capacity Factor

Investment Decisions

The investment decisions for generating units are made using dynamic programming as described previously. In order to limit the number of states considered, a truncation algorithm is used.

Truncation of Non-Optimal States:

The theory of state truncation is based on the assumption that the optimal plan is fairly close to being of minimum cost-to-date in each year up to the last year. This is especially true if the cost-to-date for each state is adjusted to account for the differences in the installed capacity, e.g., a state representing the addition of a big nuclear unit may have excess capacity for that year resulting in a

high cost-to-date, which when prorated by the minimum required capacity, may actually be less than the adjusted cost-to-date of a state with small units. The criterion for determining the minimum required capacity is either minimum percentage of reserve or fixed LOLP index.

The method of state truncation is to eliminate states in years when the number of states exceeds a specified number by first determining the minimum adjusted cost-to-date in the previous year. States in the previous year which have adjusted costs above a certain ratio to the minimum are then flagged. States in the present year whose backward pointers indicate a transition from a flagged state are then eliminated. If the resulting number of states in the present year still exceeds the maximum, the cost ratio is reduced by a factor more than once if necessary, and the elimination process repeated.

Selection of Plant Sites:

Generation expansion should ideally be solved together with transmission expansion. It is, however, not practical to do so. In most cases, transmission costs can be ignored in the generation expansion studies because they are small compared to the cost of generating capacity and they may be roughly the same for different generation expansion plans. In cases where plant sites are remote and transmission costs are significant, a model for including such costs is available in the program.

For each site, a cost-capacity step curve can be specified. A typical curve is shown in Figure 7. In this example, it is assumed that the first set of transmission additions related to this site costs \$A and is sufficient for 400 MW of generating capacity. For the next increment of 400 MW capacity, the total transmission cost for this site jumps to \$B, and so forth. The maximum capacity which can be built at this site is shown to be 1,600 MW.

Figure 7. Transmission Cost-Capacity Step Curve

The program allows a first-available year to be specified for each site. During forward dynamic programming, the program assigns the new units to various sites such that the total transmission cost is minimized. The fixed charges for the transmission investment are added to the annual costs. The siting assignment, however, cannot be applied in backward dynamic programming. Therefore, only the best plans obtained by forward dynamic programming, which include transmission costs, are available.

Adjustment for End Effects:

Since different expansion plans may have different system capacities in the last year of the study period, it is not correct to compare their revenue requirements without some adjustment to account for the end effects. The reserve and reliability constraints are used to adjust the capacities in the last year to an equal basis, either minimum reserve percentage or fixed LOLP index. The fixed charges in the last year associated with the units newly installed in that year are prorated according to the adjustment in capacity. In other words, it is assumed that only portions of these units are installed in the last year.

Furthermore, the adjusted cost of the last year can be projected for any number of years and the present worth revenue requirements for this evaluation period is added to the objective function for minimization.

Limitations

Although the loading trapezoid method for production costing is extremely fast, its accuracy requires some calibration with a more detailed and accurate production costing model. No automatic procedure is available for that calibration and there is no assurance that the same set of calibrating factors is valid as the optimal expansion plan evolves.

Hydro and pumped storage units are not modeled in the production costing nor the investment alternatives.

Effect of maintenance on system LOLP is not taken into account in the approximate method of estimating LOLP. In fact, the annual distribution of daily peak loads is replaced by the single annual peak load.

The maximum number of states in any year is limited to 200. The study period cannot exceed 20 years and the maximum number of generation alternatives is 5.

Examples and Test Cases

Not available.

Performance Capability

Maximum core storage required for OPTGEN is 240 bytes on an IBM computer.

APPENDIX C
U. MASS MODEL - A MATHEMATICAL PROGRAMMING MODEL FOR
LONG-RANGE PLANNING OF ELECTRIC POWER GENERATION

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Scope

This is an optimization program that is used for planning investments in electric power generation. The program is used to help determine for each year over some planning horizon what types and sizes of generating plants should be brought into a power system in order to meet, reliably, the system's forecasted demands for electricity. The planning objective is to minimize the present worth of all investment and operating costs that are incurred for power generation over the horizon. The mathematical program that is formulated is large scale and has been both binary and nonlinear constraints. The solution algorithm employs Bender's Decomposition Principle, a heuristic successive linearization procedure, and a Branch & Bound mixed integer linear programming code. Computation costs are low and, in the important area of sensitivity analysis, the program offers additional economies which promise to make it attractive to power system planners. Computational results are presented for a full sized generation planning problem for the New England region of the United States.

Objective

The objective is to minimize

$$\sum_{t=1}^T \sum_{g=1}^G \sum_{m=1}^{M(t,g)} IC(t,g,m) Y(t,g,m) + \sum_{t=1}^T \sum_{i=1}^I \sum_{g=1}^J \sum_{k=1}^K F(i) DUR(k) OC(t,g) X_S(t,i,g,k)$$

- where $IC(t,g,m)$ = The investment cost of one unit of the m^{th} type project from class g in year t (see method of solution)
- $OC(t,g)$ = The operating cost coefficient (\$/MWH) for the g^{th} class in year t
- $F(i)$ = The frequency of the number of weeks/yr. the i^{th} operating week occurs
- $DUR(k)$ = The number of hours/week the k^{th} demand occurs

- T = Number of years on planning horizon
- I = Number of production subproblems used per year to model seasonal variations in demand and available capacity
- K = Number of different demand levels used in modeling weekly demand
- G = Total number of generating classes
- J = Number of thermal generating classes
- $M(t,g)$ = Number of alternative investment projects available from the g^{th} class in year t
- $Y(t,g,m)$ = Number of projects of m^{th} type to be installed from class g in year t
- $X_S(t,i,g,k)$ = Prod. level in MW of the g^{th} class for k^{th} demand in i^{th} operating week for year t

Constraints

If the g^{th} class is to be treated as continuous since only one relatively small plant site is available, $M(t,g) = 1$ and $Y(t,g,1)$ is continuous. Otherwise $Y(t,g,m)$ is discrete (0,1) and satisfies

$$\sum_{m=1}^{M(t,g)} Y(t,g,m) \leq 1 \quad \forall t$$

The system reliability constraint is in terms of the probability that the total available capacity (after preventive maintenance) is less than the annual peak demand. This is expressed analytically by the following approximations:

$$\left[PMF \cdot \bar{C}_t - \bar{d}_t \right] + G(R^*) \sqrt{PMF^2 \cdot \check{C}_t + \check{d}_t} \geq 0$$

$$G(R^*) = a_1 - a_2 \sqrt{\ln \left(\frac{1}{R^*} \right)^2}$$

where $\bar{d}_t$ = Annual peak demand (normal random variable with mean $\bar{d}_t$ and variance $\check{d}_t$)

- R^* = Max. allow. value for peak risk
- PMF = One minus the fraction of installed capacity down for preventive maintenance at the time of the annual peak.

a_1, a_2 = Coefficients determined by "fitting" the analytic constraint to the actual stochastic constraint

C_t = Available capacity for peak demand without maintenance scheduling

$\bar{C}_t$ = Mean of above

$\tilde{C}_t$ = Variance of above

If $EC(t, \tau, g, m)$ and $VC(t, \tau, g, m)$ denotes the mean and variance, respectively, of the available capacity for the (τ, g, m) project in year t , and IEC and IVC refers to existing groups at $t=0$,

$$\begin{aligned}\bar{C}_t &= \sum_{\tau=1}^t \sum_{g=1}^G \sum_{m=1}^{M(\tau, g)} EC(t, \tau, g, m) Y(\tau, g, m) \\ &+ \sum_{g=1}^G IEC(t, g) \\ \tilde{C}_t &= \sum_{\tau=1}^t \sum_{g=1}^G \sum_{m=1}^{M(\tau, g)} VC(t, \tau, g, m) Y(\tau, g, m) \\ &+ \sum_{g=1}^G IVC(t, g).\end{aligned}$$

The optional plant mix constraint to restrict investment in certain classes is

$$\sum_{\tau=1}^t \sum_{m=1}^{M(\tau, g)} NC(\tau, g, m) Y(\tau, g, m) + INC(t, g)$$

$$\left\{ \begin{array}{l} \leq \\ \geq \end{array} \right\} PMIX(g) \cdot TNC_t$$

NC, INC = Name plate capacities

PMIX(g) = Fraction of total installed capacity (TNC_t)

$$TNC_t = \sum_{\tau=1}^t \sum_{g=1}^G \sum_{m=1}^{M(\tau, g)} NC(\tau, g, m) + \sum_{g=1}^G INC(t, g)$$

The demand constraint for production in each of the T-I weekly subproblems is

$$\sum_{g=1}^G X_S(t, i, g, k) - \sum_{p=1}^P X_C(t, i, p, k) \geq DEM(t, i, k)$$

where DEM = Level in MW of the demand

$X_C(t, i, p, k)$ = Demand placed on the system by the pumped hydro class p (there are P classes).

Power capacity constraints for each subproblem are

$$X_S(t, i, g, k) \leq TEC(t, i, g)$$

$$X_C(t, i, p, k) \geq TEC(t, i, J+H+P)$$

H = Number of conventional hydro-electric generation classes

TEC(t, i, g) = Total expected available capacity
= PMD(1, g) SVM(1, g) FOM(i, g)

$$\left[\sum_{\tau=1}^t \sum_{m=1}^{M(\tau, g)} EC(t, \tau, g, m) Y(t, \tau, g, m) + IEC(t, g) \right]$$

PMD = Preventive maintenance derating factor

SVM = Seasonal variation multiplier

FOM = Forced outage derating multiplier

The usage level constraints for each weekly subproblem are

$$\sum_{k=1}^K DUR(k) X_S(t, i, g, k) \left\{ \begin{array}{l} \leq \\ \geq \end{array} \right\} V(g) \cdot TEC(t, i, g)$$

and $V(g)$ = Usage level multiplier which converts available power capacity to either a min. or max. weekly energy level for that class.

Each weekly subproblem has, in addition, pumped hydroelectric constraints to insure water levels each week are returned to their former levels.

$$\sum_{k=1}^K \left[X_S(t, i, J+H+P, k) - E(p) \cdot X_C(t, i, p, k) \right]$$

$$\cdot DUR(k) \leq 0$$

$E(p)$ = Pumping efficiency

Method of Solution

Thermal plants are classified in distinct groups in terms of operating costs. Hydroelectric plants which have no operating costs are classified in terms of the ratio of weekly energy capacity to power capacity. Since system planners are usually limited in the number of alternative investment projects, the set of available plant sizes is finite. Only one

project can be chosen from each generation class in each year.

The structure of the problem may be represented as follows where y represents the investment decision vector and x_{ti} the operating decision vector:

$$\min. \underline{c}^T y + \underline{h}_{ti}^T x_{ti}$$

Subject to

$$y \in S_1$$

$$y \in S_2$$

$$Dy \leq d$$

$$y \geq 0$$

$$Ax_{ti} + B_{ti} y \geq b_{ti}$$

$$x_{ti} \geq 0$$

where $S_1 = \{Y|Y \text{ obeys the nonlinear reliability constraint}\}$

$S_2 = \{Y|Y(t,g,m) = 0 \text{ or } 1 \text{ if } g \text{ is a discrete class}\}$

$$\text{Let } S = S_1 \cup S_2 \cup \{y|Dy \leq d, y \geq 0\}$$

Then given a particular y , it is seen that the weekly subproblem becomes

$$\min \underline{h}_{ti}^T x_{ti}$$

Subject to

$$Ax_{ti} \geq (b_{ti} - B_{ti} y)$$

$$x_{ti} \geq 0$$

After an appeal to Bender's decomposition principle, the entire program is defined as

$$\min_{y \in S} \left\{ \underline{c}^T y + \max_{w^n \in W} \left\{ \sum_{t=1}^T \sum_{i=1}^I (b_{ti} - B_{ti} y)^T u_{ti}^n \right\} \right\}$$

$$\text{where } w^n = \{u_{11}^n, \dots, u_{ti}^n, \dots, u_{TI}^n\}$$

and $w^n =$ The n^{th} dual basic feasible solution to the production subproblem.

$$W = \{w^n, n=1,2,\dots,N\} = \{A^T u_{ti} \quad h_{ti}; u_{ti} \quad 0, \forall t, i\}$$

Although the set W is not available, it is possible to apply the decomposition principle indirectly

through an iterative algorithm.

$$\text{Define } W_{n+1} = W_n \cup \{w^{n+1}\} \quad W_1 = \{w^1\} \quad n = 1, 2, \dots, N$$

Then given W_n , the decomposed master problem is solved for y using $W = W_n$. This defines a feasible (although generally non-optimal) investment plan Y and an upper bound for the cost. Next, under the investment outlined the T-I weekly subproblems are solved and the total cost derived. In addition, another dual feasible solution is added to the set W_n to obtain W_{n+1} for the next iteration. As this algorithm proceeds, $W_n \rightarrow W$ and the cost upper bound converges to the minimal cost of the original program.

Due to the nonlinear constraints on y , a heuristic procedure based on successive linearizations is employed. Each time the set of dual basic feasible solutions is augmented, the reliability constraints are re-linearized.

Suppose at the $n-1^{\text{th}}$ iteration of the master program the reliability constraints (S_1) had been linearized and represented as

$$g_t(y) \geq 0 \quad t=1, \dots, T$$

Then the new constraints for the n^{th} iteration are

$$g_t(\underline{s}^n) + (\underline{y} - \underline{s}^n)^T \nabla g_t(\underline{s}^n) \geq 0$$

where

$$\underline{s}^n = (1 - \alpha) \underline{s}^{n-1} + \alpha \underline{y}^{n-1} \quad \alpha \in (0,1)$$

and $\underline{y}^{n-1}$ is the solution obtained on the $n-1$ iteration. A mixed integer code is used to implement the programming procedure with the linearized constraints. The initial $\underline{y}$ is arrived by ansatz and the set W is initialized with a number of corresponding dual basic feasible solutions.

Production Decisions

For a complete discussion of the role production plays in the programming method, see above. In addition, we should note that associated with each operating subproblem there is a "frequency parameter" indicating the number of weeks during the year that a particular weekly allocation subproblem is assumed to occur. The total cost is the sum of every cost corresponding to the subproblem weighted by these "frequency parameters". Each weekly allocation subproblem is characterized by a weekly demand model, power capacity available from each generating class and weekly energy capacity for each hydroelectric class. The duration parameter associated with the demand level defines the number of hours/week that demand is at the level specified by the corresponding demand level. Available power capacity in each generation class is given by a linear derating to represent preventive maintenance and forced outage.

Investment Decisions

The optimal investment program is arrived at through an iterative algorithm described in Method of Solution. All costs are defined in present worth and investment costs are represented as a single cash outlay occurring at the time of installation. Included are property taxes, insurance, depreciation, fixed O&M costs and other costs independent of operation. End effects are treated by assuming that demand is constant after the planning horizon and plants slated for retirement are replaced by identical plants. Due to increases in reliability as plants mature, excess capacity may result from installation of too many plants at the end of the planning horizon. This problem is alleviated by an artificial extension of the planning horizon by an amount equal to the maximum immature period of all generation alternatives.

Limitations

Plant capacity is not allocated on a plant by plant basis, rather on the aggregate level of each generation class. Linearization approximations are used to derive operating cost coefficients for fuel and variable O&M. The iterative algorithm is terminated when cost convergence as well as convergence in feasibility occurs. If the cost obtained from the solution of the linearized master program is within a specified error of the total cost of the investment plan, convergence in cost is said to occur. Feasibility convergence requires that the linearized and actual reliability constraint functions are sufficiently close at that iteration. Plant location decisions and necessary investments in transmission and distribution equipment are not considered.

Examples and Test Cases

With the hope of duplicity, a 1971 problem which had been previously solved was solved using this approach. A planning horizon of 1977-1995 was specified. The cost of capital was fixed at 8.6%, and the maximum allowable peak risk was 0.000385 (no more than one day of failure per 10 years elapsed).

```
# Discrete Gen. Classes = 2
# Confs. Gen. Classes = 2
# Gen. Classes not under invstmt.
#   alternatives = 10
# Thermal Gen. Classes = 0
# Conventional hydroelectric classes = 3
# Pumped hydroelectric classes = 3
```

New investment alternatives:
Nuclear-Discrete
Intermediate Fossil-Discrete
Gas Turbines (245MW)- Continuous
Pumped Hydroelectric (250MW) - Continuous

Twenty alternative investment projects are permissible in the discrete classes.

To reduce the excessive computation time, the linearized master program was decomposed into three 9-year master subproblems with respective starting

date of 1, 6, and 11 years. This results in a restriction of the solution space and a consequent increase in minimum cost. Due to uncertainties in many variables, these introduced errors may not be significant, however.

Most of the expansion program was made up of nuclear projects. Total cost was $\$18499.7 \cdot 10^6$ composed of $\$13201 \cdot 10^6$ investment costs and $\$5298 \cdot 10^6$ operating costs.

Performance Capability

The above test case converged with nine iterations of the solution method. One hour of CPU time on a CDC 3600 was required which was composed of 53% spent solving production allocation subprograms and 47% in solving the master programs. It has been implemented in batch mode on a CDC 6600 computer; total computation time was 426 system seconds and the core requirement was 300 K octal words.

APPENDIX D MIT MODEL - ECONOMIC ENVIRONMENTAL SYSTEM PLANNING PACKAGE

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Scope

The Economic-Environmental System Planning Package is a set of generation expansion planning programs designed to explicitly consider the feasibility and cost of meeting environmental standards. Various parts of the package have evolved from the ALPS expansion planning model, developed at the Hanford Engineering Development Laboratory, as well as several power system operation and environmental models developed at MIT.

As a generation expansion planning tool, the model exhibits several unique characteristics:

- Expansion alternatives are characterized by a plant type, fuel type, nominal capacity, site type, thermal pollution abatement technology and air pollution abatement technology.
- The cost and performance characteristics of air pollution controls are explicitly incorporated.
- The feasibility of expansion alternatives is tested by comparing performance to emission and ground level air quality standards.
- The required minimum stack height for meeting air quality standards is determined.
- The cost and performance of water pollution controls are explicitly incorporated.

- The feasibility of expansion alternatives is tested by comparing performance to water quality standards.
- The required design characteristics of water quality control technologies are determined.
- Consumptive water use, land requirements and environmental residuals are also determined.
- The incorporation of a site availability constraint.

The following characteristics apply to the more conventional aspects of the package:

- Plant types can include hydro and pumped storage.
- Incorporates both capacity and energy constraints in determining the need for new units.
- Incorporates constraints on the rate of introduction of new unit types.
- Incorporates fuel availability constraints, including detailed representation of nuclear fuel requirements.
- Utilizes separate production cost model.

Objective

The objective function is the sum of the present worth of future capital and operating costs, given as follows:

$$Z(T) = Z_{\text{plant}}(T) + Z_{\text{fuel}}(T)$$

$$Z_{\text{plant}}(T) = \sum_{v=1}^T \sum_{j=1}^J C_{jv} \cdot X_{jv}$$

$$Z_{\text{fuel}}(T) = \sum_{t=1}^T \sum_{v=-V}^t \sum_{j=1}^J F_{jvt} \cdot \text{CAPFAC}_{jvt} \cdot \text{PER}_t \cdot \text{CAP}_{jv} \cdot X_{jv}$$

- where $Z(T)$ = Total capital and operation costs (dollars) associated with a given system design over time interval $0 \leq t \leq T$
- v = Time at which alternative becomes operational $-V \leq v \leq T$
- J = Total number of alternatives
- C_{jv} = Present worth of capital and operating (other than fuel) costs of an alternative of type j and vintage v (dollars)

X_{jv} = Number of type j alternatives with vintage v to be built

CAPFAC_{jvt} = Capacity factor in period t of type j alternative with vintage v
 $0 \leq \text{CAPFAC}_{jvt} \leq 1$

PER_t = Length of period t (hours)

CAP_{jv} = Capacity of an alternative of type j and vintage v (kW)

The expansion model selects the decision variables X_{jv} and CAPFAC_{jvt} (see section on solution techniques for the method of determining CAPFAC_{jvt}) which minimize $Z(T)$, subject to the constraints imposed.

Constraints

Several constraints are utilized in the formulation of the expansion planning model which aids in the reduction of feasible sets of plant expansion alternatives.

One of these is an installed capacity constraint which effectively operates as a reserve margin criteria. It is formulated as follows:

$$\sum_{j=1}^J \sum_{v=-V}^t \text{PAV}_{jvt} \cdot \text{CAP}_{jv} \cdot X_{jv} \geq \text{MAXLOAD}_t \cdot (1 - \xi_t)$$

$t = 1 \dots T$

where PAV_{jvt} = Mean expected availability in period t of plant type j with vintage v

CAP_{jv} = Capacity of plant type j with vintage v

X_{jv} = Number of type j alternatives with vintage v to be built

MAXLOAD_t = Mean expected maximum system load in period t

ξ_t = Required margin of spare capacity in period t

The model also utilizes an energy demand constraint to ensure sufficient total energy is available from the installed additions. The constraint requires that the energy produced in period t by all plants built before period t (except pumped storage plants) minus the transmission and pumping losses associated with the pumped storage plants, must be greater than or equal to the expected energy demand in period t .

Algebraically,

$$\sum_{j \in PS} \sum_{v=-V}^t PER_t \cdot CAPFAC_{jvt} \cdot CAP_{jv} \cdot X_{jv} - \sum_{j \in PS} \sum_{v=-V}^t (1/\eta_{jv} - 1) \cdot PER_t \cdot CAPFAC_{jvt} \cdot CAP_{jv} \cdot X_{jv} \geq ED_t$$

$$t = 1 \dots T$$

where PER_t = Length of period t

η_{jv} = Overall efficiency of a pumped storage hydro plant of type j and vintage v

ED_t = Mean expected energy demand in period t

Note that this formulation does not allow energy to be stored from one time period to the next.

The program also incorporates constraints which permit existing and previously committed units to be included in the set of future generation units. Their respective formulations are as follows:

$X_{jv} = XC_{jv}$ for existing units

$X_{jv} \geq XC_{jv}$ for committed units

where XC_{jv} = Number of plants of type j with vintage v previously built or committed

The program includes a constraint which limits the rate at which new units of a given plant type can be added to the system. The following formulation is used:

$$\sum_{j \in R_i} X_{jv} \leq XR_{iv}$$

where R_i = Set of plant types included in class i

XR_{iv} = Cumulative number of plants in plant type class i that may be built in vintage period v

Two different plant siting constraints are utilized in the model; one is for hydro and pumped storage plants and one is for thermal plants.

The hydro site constraint limits the number of hydro or pumped storage plants of capacity HSZ_h or larger to be equal to or less than the specified number of sites which can support plants of capacity HSZ_h or larger.

Algebraically,

$$\sum_{j \in HS_h} \sum_{v=1}^T X_{jv} \leq NHSA_h$$

where HS_h = Set of all hydro and pumped hydro plants with capacity HSZ_h or greater

$NHSA_h$ = Number of hydro sites available which can support hydro or pumped hydro plants of capacity HSZ_h or greater

The thermal site constraint is similar, except that it measures site size in terms of four environmental resources, air pollution, land use, water use and heat dissipation, as follows:

$$\sum_{j \in TS_{alcws}} \sum_{v=1}^T X_{jv} \leq NTSA_{alcws}$$

where TS_{alcws} = The set of all thermal plants which require site type s with at least the quantity of environmental resources as indexed by $a, l, c,$ and w .

a = Index of air pollution level

l = Index of land amount

c = Index of consumptive water use

w = Index of heat dissipation capacity

$NTSA_{alcws}$ = Number of sites of type s available which can support thermal plants with the environmental resource requirements indexed by $a, l, c,$ and w or greater.

In addition to several constraints relating to nuclear fuels (not discussed here because of the detail involved), the program also recognizes two types of fossil fuel constraints. One concerns limiting the amount of fuel available at a given price level, as follows:

$$\sum_{t=1}^T NFP_{fmt} \leq UFA_{fm}$$

$f = 1 \dots 13$

$m = 1 \dots M_f$

where NFP_{fmt} = Amount of fuel type f purchased in period t at price level m

UFA_{fm} = Quantity of fuel type f available at price level m

The second fuel constraint works in conjunction with the first, and limits the amount of fuel consumed to the amount purchased in a given period, or

$$\sum_{j \in F} \sum_{v=-V}^t FC_{fjvt} \cdot X_{jv} = \sum_{m=M_f} NFP_{fmt}$$

$$t = 1 \dots T$$

$$f = 2 \dots 13$$

where F = The set of fossil fuel types

FC_{fjvt} = The amount of fuel of type f ($f = 2 \dots 13$ for fossil fuels) consumed by a plant of type j and vintage v in period t

NFP_{fmt} = The amount of fuel type f purchased in period t at price level m

The preceding constraints are an integral part of the plant expansion component of the economic-environmental system planning package. Two related sub-models which evaluate the air and water environmental performance of expansion alternatives also contain logic which constrains the choice of future plant additions.

The air quality model constrains the choice of alternatives to those which do not meet the following user-definable criteria:

- Stack emission standard
- Three-hour ground level air quality standard
- Twenty-four hour ground level air quality standard
- Annual ground level air quality standard

The logic incorporated in this sub-model includes a dispersion model to calculate the relevant performance measures for various types of sites.

The water quality model performs similar types of constraint actions for alternatives which cannot meet user-specified water quality criteria, viz:

- The plant requires more than a specified limit of river or estuary flows
- The dilution flow, if required, is greater than twice the normal plant cooling water flow
- The temperature standards cannot be met within defined mixing zone with maximum dilution flow
- A small lake site has a loading less than or equal to 0.5 acre per megawatt
- The Froude number for a surface discharge is less than 3.6 or greater than 25

Method of Solution

As presently configured, the Economic-Environmental System Planning Package is comprised of four major parts, each possessing a number of sub-models. They are the Generation Expansion Model (GEM), the Site Evaluation: Air Model, the Site Evaluation: Water Model and the Production Cost Model.

The expansion planning algorithms themselves are contained within the GEM portion of the model. Using estimated capacity factors for generating units, the sub-models of GEM perform the accounting and some constraint violation tests and prepare the plant data for the expansion optimization. The optimization procedure itself is an IBM-supplied linear programming code designated MPSX (Mathematical Programming System Extended), which uses the revised simplex method of solution with bounded variables and range constraints.

Following the optimization, plant additions are transferred to the probabilistic simulator SYSGEN to determine optimum capacity factors for these unit additions. (The use of SYSGEN is not to be confused with the "Production Cost Model", which has an environmentally-oriented purpose.) The resulting capacity factors from SYSGEN form the basis for a new capacity factor estimate to be used in the optimization routine. The optimization routine and SYSGEN thus form an iterative loop which is repeated until the capacity factor estimates converge.

The Site Evaluation: Air Model works in conjunction with the accounting portions of GEM. It consists of a boiler model, which contains emission factors for different fuels and boiler firing patterns; a minimum stack height model; and a meteorological dispersion model using the double Gaussian dispersion formula. The dispersion and stack height models are used iteratively until either the air quality standards are met or the maximum stack height is reached. Infeasible solutions are passed back to the GEM accounting routines. Cost and operating data are also transferred.

The Site Evaluation: Water Model also works in conjunction with the accounting portions of GEM. Various engineering models are used to determine the performance of plants in different types of cooling and discharge situations. Infeasible solutions, costs and performance data are transferred back to GEM.

The Production Cost Model is separate and not to be confused with SYSGEN, the probabilistic simulation routine. The Production Cost Model is a time sequence simulator for more closely analyzing environmental performance over a limited time period, such as minimum stream flow conditions during a specific season.

The Production Cost Model consists of a maintenance scheduler and a unit commitment simulation. The actual formulation of these sub-models is unclear from the standpoint of their respective objective functions. The maintenance scheduler, which is stated to be formulated as a mixed-integer program, is claimed to have the capability

of maintenance scheduling and unit shut-down for either economic or environmental reasons. The Unit Commitment Model, which is formulated as a linear program, is said to produce operating costs as well as air and water environmental impacts.

The exact purpose of the Maintenance Scheduler and Unit Commitment Model are somewhat unclear since, on the one hand, a long-range planning solution would not involve the associated amount of detail and, on the other hand, if done more precisely, would involve a much more refined technique than is apparently intended in the models described.

Production Decisions

As stated earlier, the Production Cost Model utilized by GEM is the probabilistic production simulator SYSGEN. While the iterative procedure between SYSGEN and the linear programming optimization is somewhat unique, the actual production cost code is based on the Booth-Balerieux approach. Since this approach is well-known, no further discussion of the particular formulation appears warranted.

What is unclear, however, is the actual performance of the iterative procedure and its ability to converge with the year-by-year and plant-by-plant results of SYSGEN. Available documentation does not permit an evaluation of this aspect of the model's performance.

Investment Decisions

The linear programming formulation of the optimization procedure will determine a near-optimum set of system investments over time from the alternatives supplied. Since all time periods are considered simultaneously, the dynamics of the problem are properly considered. Some error may be introduced by linearizing the discrete nature of actual unit additions. As previously discussed, the actual model performance is dependent upon the ability to converge the estimates of unit capacity factors.

Limitations

Based upon available information, no inherent program limitations have been identified.

Examples and Test Cases

Not available.

Performance Capability

Not available.

APPENDIX E

PUPS - PLANNING OF UNCONVENTIONAL POWER SOURCES

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Scope

PUPS was designed for the purpose of studying

the economic feasibility of tidal power in the Bay of Fundy. It develops a near-optimal long-range generation expansion plan for a region, using screening curves and snapshot-year analysis. The resulting plan is, therefore, made up of a series of static optimizations.

The following combination of features makes it a unique tool:

- Chronological simulation of hydro, pumped storage, and system absorption of unconventional power sources
- Mix of thermal generation is optimized by screening curves for the snapshot years
- LOLP criterion is met by adding combustion turbines
- Expansion plan between snapshot years is interpolated
- Automatic comparison of an alternative expansion plan against the base case plan to provide the cost differences
- Up to 500 generating units can be modeled and 50 years of expansion is still computationally feasible

Objective

No explicit objective function is used in the PUPS program because it is only a pseudo optimization program. It is, however, equivalent to a series of static optimizations of the generation mix for each snapshot year with interpolation in between. The static optimization is accomplished using screening curves which traditionally have been used by system planners.

The implicit objective of the screening curves is to minimize the annual cost of the power system for the snapshot year. The annual cost consists of the following components:

- (1) Annual fixed charge of new generating units to be added, including fixed O&M
- (2) Annual fuel cost and variable O&M for new generating units serving the entire system load

The procedure is only a true optimization if there is no existing generation, the system load remains constant and unit sizes are not discrete. However, for long-range studies, the procedure produces results that closely resemble optimal expansion plans derived by more sophisticated dynamic optimization models.

Constraints

For the planning functions of the model, the following constraints are imposed:

Reliability Constraint:

The generation system for each snapshot year must satisfy an LOLP criterion. Two definitions of LOLP are possible:

- (a) LOLP is based on 260 daily peak loads, or
- (b) LOLP is based on hourly loads over the entire year.

In either case the effect of maintenance can be approximated as an option.

In between snapshot years, the reliability constraint takes the form of a minimum reserve percentage, linearly interpolated between the reserve requirements of the two snapshot years.

Capacity Factor Constraints:

The addition of nuclear units is limited by a specified minimum annual factor below which nuclear units cannot be technically operated. This overrides the economic penetration of nuclear units.

A maximum capacity factor can be specified for combustion turbines to limit their economic expansion.

Method of Solution

The program uses a snapshot-year approach. The intervals between snapshots can be varied from snapshot to snapshot. For each snapshot year, a detailed hour-by-hour simulation of the operation of the non-thermal generation system is made. This is performed by CATO. See Figure 1 for the functional block diagram of the sub-models used in a snapshot year.

The hydro system and storage expansion are input data. The result of CATO is the annual thermal load duration curve which is used for both OPTMIX-TCC and PROCOX. OPTMIX applies the screening curves to the thermal LDC and derives the expansion of the non-peaking thermal generating units from the previous snapshot to the current snapshot year. The peaking combustion turbines are added one at a time by TCC until the LOLP criterion is met. The resulting thermal system structure is combined with the thermal LDC in PROCOX to compute the annual thermal production cost.

After a snapshot analysis is completed, the year-by-year expansion plan between the previous and the current snapshot years is obtained by FILLIN which basically arranges the schedule to match the optimal mix as closely as possible and at the same time satisfy the minimum reserve constraint.

The annual revenue requirements are computed and their present worths cumulated as the snapshot analysis marches forward in time. At the completion of the last snapshot year, the annual cost of the last year is projected to any number of years to form the evaluation period.

Production Decisions

The simulation of the production decisions in the operation of the generation system is performed by CATO and PROCOX. Their basic functions and algorithms are summarized below.

Scheduling of Non-Thermal Generation by CATO:

The objective of the CATO model is to determine in each snapshot year, the generation schedule of

Figure 1. Functional Relationships for Snapshot Year Analysis

all the non-thermal resources, in order to identify the residual load which is to be supplied by the thermal system.

The method of approach is a deterministic simulation based on a chronological load model of 8736 hourly loads. No optimization is performed. Rather, decision rules are applied to approximate an optimal scheduling policy. The scheduling sequence is as follows:

- (1) Must-run generation
- (2) Unconventional generation
- (3) Controllable hydro
- (4) Storage devices

The absorption from unconventional generation, the generation from all hydro units and the restitution from storage are deducted from the original load. The storage pumping schedules from thermal generators are added to the original load. The resulting load is to be supplied by the thermal units. That load is referred to as the thermal load.

A second result of CATO is the time series of residual unconventional generation unabsorbed in the primary market and available to the secondary market.

Algorithms for Utilizing Unconventional Generation: CATO applies the following decision rules for simulating the utilization of unconventional generation.

- (a) Direct Absorption: The basic limitation in determining the direct absorption is the must-run generation. Three components are identified in the must-run generation: hydro, nuclear, and fossil must run. The load above the must-run generation can be supplied by direct absorption from tidal generation.
- (b) Retiming Policies: Three different storage policies can be simulated in CATO, depending on the characteristics of the storage devices made available for retiming the residual.
 - Policy A
A storage device is dedicated to retiming of unconventional generation and is operated on a weekly basis.
 - Policy B
A storage device is dedicated to retiming of unconventional generation and is operated on the same cycle as the unconventional generation.
 - Policy C
All storage devices in the system are used for peak shaving. Priority is for retiming unconventional generation. The retiming is simulated on a weekly basis.

Algorithms for Scheduling Hydro and Storage Devices: Hydro generation is scheduled by peak shaving with a predetermined amount of hydro energy on a

weekly basis. The basic algorithm for scheduling storage devices is similar. The generation schedule is determined by peak shaving but the amount of energy is unknown. The charging schedule is found by valley filling the same amount of energy divided by the round-trip efficiency. The amount of cycled energy is determined iteratively to reach the optimal economic conditions subject to the energy storage capacity constraint.

The optimal economic condition is approximated by the following inequality:

$$(p - \text{NUCAP}) \leq \gamma (r - \text{NUCAP})$$

where p and r are the pumping and restitution load level, respectively, NUCAP is the total derated nuclear capacity in the system and γ is the roundtrip efficiency.

The above assumes that pumping with nuclear energy is always economical and that the system incremental cost function is proportional to load level above the nuclear capacity.

Annual Thermal Production Costing by PROCOX:

The PROCOX model estimates the annual production cost associated with a given thermal load and a set of thermal generating units.

The method of approach is based on an annual thermal load duration curve with derated unit capacities for incorporating the effect of forced and planned outages.

The units are stacked under the thermal LDC according to average operating cost. Each unit is derated: base load and cycling units by forced outage and maintenance, and peaking units by forced outage only.

The main result of PROCOX is the annual production cost for the entire system. Other results are:

- System fuel consumption and cost per fuel type
- Capacity factor, or equivalently the energy production of each unit
- Fuel cost and O&M cost for each unit

Investment Decisions

The investment decisions are made for a snapshot year by the OPTMIX and TCC models. Subsequently, the decisions for the intermediate years are made by FILLIN.

Optimization of Thermal Generation Mix by OPTMIX:

The OPTMIX model determines for each snapshot year the mix of non-peaking thermal units based on economics and operating constraints, given the thermal mix of the previous snapshot year.

The methodology of OPTMIX is a static optimization based on the annual thermal load duration curve and derated capacities. Discrete unit sizes

are considered. The scale effect is indirectly taken into account by the snapshot-year approach, if the load growth between two successive snapshot years is high enough to allow the installation of large units. The economic aspects are modeled by the screening curves and the technical constraints are reflected on the unit capacity factors.

The screening curve approach to determine the optimal mix when no technical constraints apply is shown in Figure 2.

Figure 2. Screening Curve Approach to Determine the Optimal Thermal Generation Mix

Definitions:

C_p = Annual fixed cost (capital charge plus fixed O&M) of peaking units in \$/kW.

γ_p = Operating cost of peaking units in \$/kW-year at 8760 hours.

A_p = Availability of peaking units.

$I_p = (C_p/A_p)$ Effective annual fixed cost.

Similar notations are defined for base load and cycling units by changing the subscripts to "n" and "c", respectively.

The annual cost function of each kW of derated capacity is shown in Figure 2 as a straight line with a slope equal to the operating cost γ and an intercept equal to the effective fixed cost I . These screening curves combined with the annual thermal load duration curve demonstrate the economics of installing peaking units to serve the portion of the load with load factor less than H ,

$$\text{where } H = (I_c - I_p)/(\gamma_p - \gamma_c)$$

Moreover, they show that cycling units should be installed to serve the load which occurs more than $H\%$ of the time up to the point where base-load units take over at load factor Q ,

$$\text{where } Q = (I_n - I_c)/(\gamma_c - \gamma_n).$$

The load levels which correspond to the load factors H and Q are denoted by Y^* and X^* , respectively. Making the assumption that derated capacities are equivalent to firm load levels, the value X represents the optimal amount of derated base load capacity, and

$$(Y - X) = \text{The amount of cycling capacity.}$$

However, technical constraints can override the optimal conditions. For instance, there is a minimum capacity factor for nuclear units which prevents them from operating in a cycling mode. There may also be a maximum capacity factor for gas turbines above which their reliability becomes greatly impaired. These constraints modify X^* and Y^* to $\hat{X}$ and $\hat{Y}$.

An integer number of base-load units will be added to the existing ones, up to matching $\hat{X}$ within some tolerance. An integer number of cycling units will be added to the base-load units and the existing cycling units up to matching $\hat{Y}$ within some tolerance.

Peaking Capacity Planning by TCC:

Once OPTMIX has defined the non-peaking structure, the system security level can be estimated by a probabilistic calculation. This is done by computing a yearly Equivalent Load Duration Curve (ELDC) on the basis of the thermal load duration curve and the forced outages of all the non-peaking units. Then peaking units are added one at a time until the loss-of-load probability reaches the desired reliability level.

The thermal LDC can be based on 8736 hourly loads or 260 daily peak loads according to the selection of a reliability index. The impact of maintenance is approximated by valley filling the LDC with the MW-days of maintenance outages.

Interpolation Between Snapshot Years by FILLIN:

Given the new units which are to be installed between two snapshot years, and the linearly interpolated reserve requirements for the intermediate years, these new units are scheduled for installation according to the following criteria:

- The relative mix of the alternative types of new generation should be close to the target mix for each intermediate year. For example, if the target mix is 1.3 nuclear units in a particular year, the program will consider the possibilities of either one or two nuclear units.
- Of all the possible combinations of alternative types in each year, that combination which offers the least installed capacity and yet meets the reserve requirement will be selected.

The production costs for the intermediate years are obtained by PROCOS operating on the thermal load duration curve which is interpolated between the snapshot years and using the actual thermal system structure for these intermediate years.

Limitations

Because the expansion plan is the result of a series of static optimizations, it is not dynamically optimal. This fact limits the application of PUPS to really long-range studies for which the exact timing of unit installations is not so critical. However, combined with judgment, PUPS can still be used for near-term planning.

Expansion planning with storage devices is not an automatic feature in PUPS. It requires the input of a storage expansion scenario. Similarly, automatic selection of new hydro units to be installed is not possible.

The production costing method in PROCOS does not take into account accurately the effect of random outages. The effect of maintenance schedules on the production cost is also not modeled accurately. The derating procedure (by forced outage rate and planned outage rate) is only valid for large systems with many units. However, it may be argued that this approximation is acceptable if one only wants the cost differences between alternative expansion plans whose accuracy should be acceptable because the alternatives are developed by the same model with the same set of approximations.

Examples and Test Cases

No published example and test case are available. The program was used extensively in the Bay of Fundy Tidal Power Study for developing 25-year expansion plans with and without tidal power for two regions, the Canadian Maritime Provinces and the New England region. Typically, a snapshot interval of 5 years was used.

The expansion alternatives considered were nuclear, coal, combustion turbines and pumped storage.

Performance Capability

The program requires 57 K words or 230 K bytes of core storage.

For a test case with 7 snapshot years, 25-year expansion period, 40 generating units expanding to 120 units, 3 hydro units, and one equivalent pumped storage unit, the execution time on a UNIVAC 1108 computer was 90 CPU seconds.

APPENDIX F MNI-GRETA - GENERATION PLANNING MODELS OF ELECTRICITE' DE FRANCE (EDF)

Staff

Electricité de France

Scope

There are a number of models developed and used by EDF for long- and medium-term generation and transmission planning. Two models are described here, GRETA and MNI. They are not directly integrated into a single computer program. Two other models, DYNA and MEXICO, are used for transmission planning. Each of the four models addresses a sub-problem of the global generation and transmission planning problem, as follows:

- MNI for long-term generation planning
- GRETA for medium-term production costing and adjustments to the long-term expansion plan
- DYNA for long-term studies of plant location and transmission network development
- MEXICO for medium-term studies of the transmission network reinforcements

For long-term studies, dynamic models (MNI and DYNA) are used. MNI uses optimal control methods while DYNA is a linear program encompassing all the years in the study period. For medium-term studies static models (GRETA and MEXICO) are used, resorting mainly to Monte Carlo simulations for annual analysis. For the interactions between these models, see Figure 1.

This synopsis will describe the MNI and GRETA models only.

Objective

The objective of the MNI model is to minimize the total present worth of investment, expected production cost and cost of unserved energy, discounted at a given rate over several decades. Predicted equipment and fuel prices are entered as deterministic data, while load, hydraulic inflows and forced outages are treated as random variables. The objective function is:

$$\text{Min} \sum_{t=1}^{\infty} \left(\frac{1}{1+d} \right)^t * \left[G_t(X_i^t) + \sum_i K_i U_i^t \right]$$

Figure 1. Decomposition of the Planning Problem into Subproblems for Suboptimization

subject to:

$$\underline{U}_i^t \leq U_i^t \leq \overline{U}_i^t$$

$$X_i^{t+1} = X_i^t + U_i^t$$

$$X_i^0 = \text{Initial state (known)}$$

where d = Discount rate

K_i = Annual investment cost associated with class i (constant annuities and replacement by same type at end of lifetime)

U_i^t = Capacity investment in class i made in year t

$G_t(X_i^t)$ = The expected production cost during year t given the system structure X_i^t in that year. The failure cost is also included.

The production cost G_t is estimated from a sub-model within MNI which is different from GRETA.

This sub-model is actually a production costing

model incorporating the failure cost through a fictitious expensive unit loaded after the last unit in the system. The objective function is to minimize the expected annual production cost.

$$\text{Min}_{M^t, R^t} Z = \sum_h P_h \sum_j P_j \sum_{t=1}^{12} Z_t (M^t, R^t, H_h^t, L_j^t)$$

subject to:

$$\underline{M}_i \leq \sum_t M_i^t \leq \overline{M}_i$$

$$\underline{R}^t \leq R^t \leq \overline{R}^t$$

where M_i^t = Maintenance status of unit i in month t

R^t = Hydro release during month t

H_h^t = Water inflow with probability P_h

L_j^t = Load level with probability P_j

Z_t = The monthly production cost if random variables are H_h^t and L_j^t and decision variables are M^t and R^t .

The objective of GRETA is to simulate the optimal operation of a power system which contains hydro and storage devices, taking into account the uncertainty of load, thermal generation and water inflows. It is an accurate model suitable for short-term and medium-term planning. Because of its computational requirement, it cannot be directly integrated with the MNI model for generation capacity planning.

Constraints

In the MNI model, the constraints on the optimization are expressed as upper and lower bounds on the admissible generation additions for each generation alternative.

A significant departure from the U.S. practice is the absence of reliability constraints. Reliability is considered as part of the cost function. A failure cost is computed for the expected unserved energy and added to the generation fuel and operating cost. Usually this failure cost per kWh is assumed to be \$0.50 to \$1.50.

In the GRETA model, the hydro system is represented by three equivalent units with a limited capability to model their interactions. Operating constraints are ignored. Storage devices are constrained by their reservoir volume.

Method of Solution

The MNI long-term expansion problem is formulated as an optimal control problem using Pontryagin's maximum principle. It is solved by a steepest-descent algorithm.

This approach permits a timewise decomposition in which co-state variables (in the context of Pontryagin's maximum principle) play an important role and provide useful information. A component ψ_i^t of the co-state vector is the value of use of equipment i at year t , i.e., the present worth of expected cost reduction if 1 kW of equipment i is added to the system in year t .

GRETA is a production costing and security assessment model which performs Monte Carlo simulations for the three random variables (load, thermal capacity and water inflows) and applies management/operating rules to determine annual statistics on the system operation.

In a sub-model of GRETA called PRODY, dynamic programming is used to provide optimal hydro management rules which can be used for an efficient simulation of the hydro system.

Production Decisions

In the MNI model, production decisions are made under a number of assumptions to increase the computational efficiency. On the other hand, the

GRETA model examines the effect of uncertainty much more accurately at the cost of computer time.

Production Costing in MNI:

The maintenance schedule M^t and the hydro release R^t are optimized decision variables in the problem formulated earlier. Given these energy management decisions, the production costing problem is solved on a monthly basis by deterministic analyses repeated for several occurrences of the random variables (load and water inflows).

The load model is a monthly duration curve with 10 levels corresponding to well-known periods:

- Levels 1, 2, 3, and 4: on-peak periods of work days
- Level 5: on-peak periods of Saturdays
- Levels 6 and 7: off-peak periods of work days (night)
- Levels 8, 9, and 10: remainder of weekends

This subdivision is adopted for easier scheduling of storage devices.

The thermal units are represented by their derated capacity and a single proportional cost (incremental cost).

The hydro units are aggregated into a single equivalent unit, and for each water inflow value and each water release decision, the maximum amount of energy $W_1, W_2, \dots, W_{10}$ which can be used during each level of the LDC are determined.

The storage units are aggregated into two equivalent units: one with a daily cycle and the other with a weekly cycle operation. Both units are characterized by:

- Capacity P
- Round-trip efficiency η
- Reservoir volume V

The generation schedules for the various units are determined by an iterative process whose objective is to determine the optimal pumping schedules given the hydro capability and the thermal cost function:

STEP 1: Select a marginal pumping cost λ_p

STEP 2: Determine optimal pumping schedules for λ_p . This is solved by linear programming.

STEP 3: Given the energy stored, optimize the hydro and restitution schedules (i.e., level out the thermal load.) This is a nonlinear program with linear

constraints. As a result, the marginal saving from restitution is known: λ_r

STEP 4: Compare λ_r and λ_p to determine whether pumping should be increased or decreased. Adapt λ_p accordingly. Go to STEP 1.

Note that in this production costing model, only load and hydro uncertainties are considered. Thermal forced outages are represented by capacity deration. Load and hydro uncertainties are treated by a combinatorial approach: computations are repeated for selected combinations of loads and water inflows to represent their full spectrum of occurrence and the results are weighted according to the associated probabilities.

The production costing model also determines the cost gradient vector with respect to all capacities of equipment considered (thermal and storage). This result is useful for the "investment" model which can use them as initial gradients (values of use).

Production Costing by GRETA:

The load model considers an annual energy level (specified as data), weekly energy levels for average weather conditions (Gaussian distributions with autocorrelation with the two preceding weeks), and daily weather impact (modeled through load-weather model and weather statistics).

The hydro system is aggregated into three equivalent hydro units (total equivalent capacity less than actual capacity), with a limited number of parameters to represent their interactions. (See Figure 2.)

The storage system is aggregated into two equivalent units (weekly and daily cycle). No seasonal storage is considered. Each unit is defined by pumping and generation capacities, reservoir volume and round-trip efficiency. Their scheduling is done on the basis of the weekly LDC after deduction of the hydro contribution (in a former version), or by optimization in the current version.

The thermal units are considered individually except for old units which are aggregated. They are defined by their capacity, average production cost and reliability data (steady-state forced outage rate and average duration of outages). The last thermal unit has a very high cost and is used to represent the cost of outages. Startup costs are neglected. Spinning reserve is not mentioned.

The maintenance schedule is prespecified but the optimal hydro management rules are determined by the model itself. Unit commitment is not considered on an hourly basis; rather, it is approximately handled in the weekly load duration curves.

The model is actually a package of five programs: CONS, THALE, HYDRAU, PRODY and GRETA, which performs separate functions as follows:

GRETA: HYDRO SYSTEM REPRESENTATION FOR EACH WEEK

NOTE:

Q is a decision variable.

All other quantities are data.

Figure 2. GRETA: Hydro System Representation for Each Week

CONS: CONS reads elementary load information and prepares load data samples by Monte Carlo draws. Autocorrelation and weather effect are modeled.

THALE: THALE reads characteristics of thermal system and maintenance schedules. Samples of available thermal capacity are drawn by Monte Carlo methods, using state probabilities depending on previous state only (Markov assumption, Kolmogorov equation).

HYDRAU: HYDRAU reads hydro system data and hydro inflows historical data. It defines the three equivalent hydro units (one seasonal, one weekly, one run-of-river) and the inflow sample by Monte Carlo draws or by selection of past sequences. Functions are specified for defining the must-run energy from seasonal reservoir according to the water inflow, and the fractions of seasonal release which increase the downstream energy.

PRODY: PRODY uses dynamic programming to define optimal hydro management rules.

The flowchart in Figure 3 shows the three basic steps. The following definitions of variables are needed:

- R_t = Water reserve at beginning of stage t
- A_t = Water inflow during stage t . This is a random variable with the following probability mass function:
- $$\text{Prob (inflow} = A_{it}) = \pi_{it}$$
- Q_t = Water release during stage t (in MWH)
- $G_t(Q_t)$ = Thermal saving in stage t resulting from optimal utilization of release Q_t .
- $V(R_t)$ = Value function of water reserve R_t is defined as expected savings generated by optimally managing the system from time t on with R_t as initial reserve.

By its definition, $V(R_t)$ can be written as:

$$V(R_t) = \max_{Q_t} \left\{ G_t(Q_t) + E \left[V(R_{t+1}) \right] \right\}$$

The expectation is taken over the random water inflow distribution.

The optimal water release is obtained by imposing:

$$\frac{dV(R_t)}{dQ_t} = 0$$

From this, one derives the following optimal condition:

$$G'_t(Q_t) = E \left[V'(R_{t+1}) \right]$$

where the ' denotes a derivative w.r.t. the explicit variable.

The thermal savings $G_t(Q_t)$ are determined by peak shaving the load duration curve, from which $G'_t(Q_t)$ can be computed.

The curve $V'(R_{t+1})$ can be derived by the following backward recursive process:

$$V'(R_{t+1}) = V'(R_t - Q_t + A_t)$$

$$E \left[V'(R_{t+1}) \right] = \sum_i V'(R_t - Q_t + A_t) * \pi_{it}$$

For a fixed (known) value of R_t , $E \left[V'(R_{t+1}) \right]$ can thus be expressed as a function of Q_t if $V'(R_{t+1})$ is known. Remember that $V(R_{t+1})$ is assumed to be known; its derivative $V'(R_{t+1})$ can thus be obtained easily in order to initialize the backward recursive process.

Knowing the curve $E \left[V'(R_{t+1}) | R_t \right]$ as a function of Q_t and the curve $G'_t(Q_t)$, the optimal Q_t will be obtained at their intersection. Also, the ordinate of their intersection is the marginal value $V'(R_t)$ which can be associated with the reserve R_t given the optimal decision Q_t^* .

The entire solution algorithm can, therefore, be summarized as follows:

- 1 Start with $t = T$
- 2 Determine $G'_t(Q_t)$
- 2a Select one value of R_t
 - Select one value of Q_t
 - Compute $E \left[V'(R_{t+1}) | R_t \right] = \sum_i V'(R_t - Q_t + A_{it}) * \pi_{it}$
 - Repeat for various Q_t
 - Determine Q_t^* and $V'(R_t)$.

Figure 3. Flow Chart of GRETA

- 2b Repeat for various $R_t \rightarrow$ curve $V'(R_t)$ and decision vector $Q_t^*(R_t)$
- 3 Repeat for all t backward
- 4 Determine optimal trajectory by selecting the optimal decisions $Q_t^*(R_t)$ on the basis of the expected reservoir levels given initial reservoir level R_0 and expected water inflows

GRETA

This is the simulation module. It uses various operation rules to schedule the following generation resources:

- 1 Hydro Generation
 - Seasonal release Q_t^* based on the condition that marginal thermal saving in the stage must be equal to the expected marginal value of the reserve at the end of the stage
 - Weekly hydro by peak shaving
 - Run-of-the-river hydro as base generation
- 2 Pumped storage - two units are considered: one with weekly cycle, the other with daily cycle. They are scheduled with the objective of minimizing the thermal cost.
- 3 Thermal generation - thermal units are stacked under the thermal LDC in order of increasing average production cost.

Investment Decisions

Investment decisions are made in MNI by solving the dynamic optimal control problem formulated in the Objective section using the method of steepest descent and Pontryagin's maximum principle. The exact mathematical procedure is not reported in the literature.

No investment decisions are made by the GRETA model.

Limitations

The production costing model in MNI does not treat thermal forced outages accurately. The aggregation of all hydro units into a single equivalent is also not very satisfactory. Because of these approximations, the resulting expansion plan is to be verified by running GRETA which is a more accurate simulation model.

However, the Monte Carlo simulation performed by GRETA is very costly. Its accuracy, of course, depends on how many samples are drawn. Typically, 500 to 1000 samples are needed for sufficient accuracy.

Examples and Test Cases

An example was published in the 1975 PICA Conference. The MNI model was applied to the expansion of the Mexican National Interconnected System. The study covered the period 1978-2000 divided into intervals of three to five years.

The resulting expansion plan called for maximum nuclear penetration, together with fossil-fueled generation and a moderate increase of hydro. No information on computation time was available.

Performance Capability

No information on program size is available. The CPU time for running 1000 samples in GRETA on an IBM 370/165 computer is broken down by sub-models as follows:

CONS:	3 minutes
THALE:	7 minutes
HYDRAU:	1 minutes
PRODY:	28 minutes
GRETA:	6 minutes
TOTAL:	45 minutes

APPENDICES

OF

Public Service Electric and Gas Company

APPENDIX A-1 LOAD FLOW METHODS

Problem Formulation

The voltage current relationship in a network in nodal form is given by

$$I = YE \quad (1)$$

or in the inverse form

$$E = Y^{-1}I = ZI \quad (2)$$

The complex injected power at a node (bus) i is given by

$$S_i = E_i I_i^* = P_i + jQ_i \quad (3)$$

A PQ bus i is one at which the total injected power is specified.

$$\begin{aligned} S_i^{SP} &= P_i^{SP} + jQ_i^{SP} \\ &= (P_{Gi}^{SP} - P_{Li}^{SP}) + j(Q_{Gi}^{SP} - Q_{Li}^{SP}) \\ &= E_i I_i^* \end{aligned} \quad (4)$$

A PV bus i is one at which the total injected real power and the voltage magnitude are specified.

$$P_i^{SP} = (P_{Gi}^{SP} - P_{Li}^{SP}) = \text{Re}(E_i I_i^*) \quad (5)$$

$$|E_i^{SP}| = (e_i^2 + f_i^2)^{1/2} \quad (6)$$

The system slack bus has both the magnitude and angle of its voltage specified. This bus makes up the difference between the scheduled load and generation that is caused by system losses.

An exact load flow solution is achieved when equation 4-6 are satisfied.

The complex power mismatch is derived from:

$$\Delta S_i = S_i^{SP} - E_i I_i^* \quad (7)$$

The current mismatch equation is

$$\Delta I_i = \frac{\Delta S_i^*}{E_i^*} \quad (8)$$

The most common convergence criteria used are

$$\begin{aligned} \Delta P_i &\leq \epsilon_p \text{ for all PQ and PV buses} \\ \Delta Q_i &\leq \epsilon_q \text{ for all PQ buses} \end{aligned} \quad (9)$$

ϵ_p and ϵ_q are tolerances chosen typically in the range of .01 to 10 MW/MVAR

Gauss-Seidel Method using Y_{bus}

In this method an expression for voltage is obtained for each PQ bus from equations 1 and 3

$$E_i = \frac{(P_i^{SP} - jQ_i^{SP})/E_i^* + \sum_{k \neq i} Y_{ik} E_k}{Y_{ii}} \quad (11)$$

$$\begin{aligned} \text{An alternate form is } \Delta E_i &= \frac{\Delta S_i}{Y_{ii}} = \frac{\Delta S_i^*}{E_i^* Y_{ii}} \\ &= \frac{S_i^{SP*} - E_i^{*2} \sum_{k \neq i} Y_{ik} E_k}{E_i^* Y_{ii}} \end{aligned} \quad (12)$$

The calculation is started with an estimated value for each of the voltages except the slack bus voltage which is known.

Equations 11 or 12 yield to an iterative process and the solution is approached in an iterative manner.

During the calculations, the most recent values of the voltages are used in the right hand sides of equations 11 or 12.

For a PV bus, $|E_i|$ is specified and Q_i^{SP} is not available. In equation 11, Q_i^{SP} can be replaced by Q_i^{cal} , the calculated reactive power, in $(E_i \sum_{k \neq i} Y_{ik} E_k^*)$. After evaluating E_i , its magnitude is reset to $|E_i^{SP}|$ while maintaining its new angle.

The slack bus voltage magnitude and angle are known, and require no equation.

In the nonlinear load flow problem, sometimes it may be advantageous to form an inner iteration loop for E_i in equation 11 by substituting the newly evaluated E_i from the left hand side back into E_i^* on the right-hand side. If iterated to convergence, this inner loop process entirely liquidates ΔS_i .

A variation of this method consists in solving a set of linear equations to find ΔE at each node

For a PQ node

$$P_i^{SP} + jQ_i^{SP} = (E_i + \Delta E_i)(I_i + Y_{ii} \Delta E_i)^* \approx E_i(I_i + Y_{ii} \Delta E_i)^* + \Delta E_i I_i^* \quad (13)$$

I_i is first solved from equation 1 using the latest values of E_i 's

For a PV node

$$P_i^{SP} = \text{Re} \left[E_i (I_i + Y_{ii} \Delta E_i)^* + \Delta E_i I_i^* \right] \quad (14)$$

$$|E_i^{SP}|^2 = |E_i + \Delta E_i|^2 \approx |E_i|^2 + 2 \text{Re} \{ E_i \Delta E_i^* \} + |\Delta E_i|^2 \quad (15)$$

$$\text{where } E_i = e_i + jf_i \text{ and } \Delta E_i = \Delta e_i + j\Delta f_i$$

Z-Matrix Methods

In this method equation 2 is solved directly for E in terms of I which are obtained from equation 3. In order to improve the convergence characteristics, it is useful to include, at each load bus, a fixed impedance to ground to approximate the load on the basis of the estimated voltage at this bus. The actual load specified is produced by a fringing current which is injected into each load bus to correct for the difference between actual and estimated voltage.

The typical bus voltage expression for bus n is

$$E_n = Z_{n1} I_1 + Z_{n2} I_2 + \dots + Z_{ns} I_s + \dots + Z_{nn} I_n \quad (16)$$

where I_s is the slack bus current

The approximate impedance to ground to represent load at bus k is

$$Z_{Lk} = \frac{|E_{Lk}|^2}{P_{Lk} - jQ_{Lk}} \quad (17)$$

where E_{Lk} is the initial estimated voltage for bus k .

For any bus n , the combined load fringing and generator current is

$$I_n = \left[\frac{P_{Gn} - P_{Ln}}{E_n} + j \frac{Q_{Gn} - Q_{Ln}}{E_n} + \frac{E_n^*}{Z_{Ln}} \right]^* \quad (18)$$

The corresponding new I_s from the slack bus voltage equation is

$$I_s = \frac{1}{Z_{ss}} (E_s - Z_{s1} I_1 - Z_{s2} I_2 - \dots - Z_{sn} I_n) \quad (19)$$

The corrected bus voltage is calculated from equation 16.

In these correction equations, the latest values of the injection currents available are used (Gauss Seidel Method)

At a generation bus for which a fixed voltage magnitude $|E|$ is desired, within the limitation that $Q_{min} \leq Q \leq Q_{max}$, the procedure adopted might be as follows. The voltage magnitude at bus n is corrected by injecting a current at bus n while maintaining all other injected currents constant except that at the slack bus. The new voltage at bus n is

$$\tilde{E}_n = Z_{n1} I_1 + Z_{n2} I_2 + \dots + Z_{ns} (I_s + \Delta I_s) + \dots + Z_{nn} (I_n + \Delta I_n) \quad (20)$$

where $\tilde{E}_n$ is to have the specified magnitude

Equations 16 and 20 together give

$$\tilde{E}_n - E_n = Z_{nn} \Delta I_n + Z_{ns} \Delta I_s \quad (21)$$

Since the slack bus voltage is fixed in magnitude and angle

$$\Delta E_s = Z_{s1} \Delta I_1 + Z_{s2} \Delta I_2 = 0$$

$$\text{or } \Delta I_s = - \frac{Z_{sn}}{Z_{ss}} \Delta I_n \quad (22)$$

Thus equation 21 becomes

$$\tilde{E}_n - E_n = (Z_{nn} - \frac{Z_{ns}^2}{Z_{ss}}) \Delta I_n \quad (23)$$

The additional equation to be satisfied is

$$P_n = \text{Re} \left[\tilde{E}_n (I_n + \Delta I_n)^* \right] \quad (24)$$

since the power is specified.

Equations 23 and 24 can be solved for I_n and the angle of $\tilde{E}_n$ by separating the real and imaginary parts and linearizing the equations by neglecting the $(\Delta I_n)^2$ terms.

The new current $\tilde{I}_n$ ($I_n + \Delta I_n$) is used to calculate the corresponding generator VAR value.

$$Q_{Gn} = \text{Im} \left[\tilde{E}_n \tilde{I}_n^* - \frac{|\tilde{E}_n|^2}{Z_{Ln}^*} \right] + Q_{Ln} \quad (25)$$

Equation 25 follows from equation 18.

This value of Q is checked to see if it is within regulating limits. If not, the approximate limit is used instead.

Newton Methods

Complex power at node i is given by, from equation 3

$$P_i + jQ_i = E_i \sum_k Y_{ik}^* E_k^* \quad (26)$$

Newton's method involves repeated solutions of a system of linear equations derived from equation 26. In the polar formulation, the Jacobian matrix of equation 26 gives the linearized relationship between small changes in voltage angle and magnitude, δE_i and $\delta \theta_i$, and small changes in real and reactive power, δP_i and δQ_i .

The matrix equation can be written for convenience of presentation in the following partitioned form:

$$\begin{bmatrix} \delta P \\ \delta Q \end{bmatrix} = \begin{bmatrix} H & N \\ J & L \end{bmatrix} \begin{bmatrix} \delta \theta \\ \delta E/E \end{bmatrix} \quad (27)$$

Slack bus mismatches and voltage corrections are not included in equation 27, also δQ_i and δE_i for each PV bus are absent.

The elements of equation 27 are defined by

$$\begin{aligned} H_{ik} &= \frac{\partial P_i}{\partial \theta_k}, & N_{ik} &= \frac{\partial P_i}{\partial E_k} E_k \\ J_{ik} &= \frac{\partial Q_i}{\partial \theta_k}, & L_{ik} &= \frac{\partial Q_i}{\partial E_k} E_k \end{aligned} \quad (28)$$

The partial derivatives defined above are real functions of the admittance matrix and the node voltages. Although based on a polar formulation of the problem, they should be computed by rectangular complex arithmetic in order to avoid time-consuming calculations of trigonometric functions. The alternative rectangular version seems to be slightly less reliable and rapid in convergence than the polar version.

Terms of equations 28 when $i \neq k$ are

$$\begin{aligned} H_{ik} &= L_{ik} = a_k f_i - b_k e_i \\ N_{ik} &= -J_{ik} = a_k e_i + b_k f_i \\ \text{when } i &= k \\ H_{ii} &= -Q_i - B_{ii} E_i^2 \\ L_{ii} &= Q_i - D_{ii} E_i^2 \\ N_{ii} &= P_i + C_{ii} E_i^2 \\ J_{ii} &= P_i - C_{ii} E_i^2 \end{aligned} \quad (29)$$

$$\begin{aligned} \text{where } Y_{ik} &= G_{ik} + jB_{ik} \\ a_k + j b_k &= (e_k + j f_k) (G_{ik} + j B_{ik}) \end{aligned} \quad (30)$$

The terms δP_i and δQ_i are residuals of (26) as defined below

$$\begin{aligned} \delta P_i &= P_i (\text{scheduled}) - P_i (\text{actual}) \\ \delta Q_i &= Q_i (\text{scheduled}) - Q_i (\text{actual}) \end{aligned} \quad (31)$$

The basic algorithm of the method is as follows.

From a flat voltage start ($E = 1.0$ p.u., $\delta = 0$) the Jacobian matrix (27) is formed and augmented by the column of residuals. The voltage corrections are solved by Gaussian elimination and back-substitution. The corrections are applied to the node voltages. The residuals δP_i and δQ_i are then checked. If they are sufficiently small, the problem is solved, otherwise, the procedure is repeated, starting with the formation of the Jacobian matrix.

Area Interchange Control

Each area in a multi-area load flow problem will have a scheduled net megawatt import/export. To satisfy this constraint each area is assigned a slack generator. These generator buses will have δ , P and Q variable with $|E|$ fixed. There are no equations for these generators. These are substituted by equations for the area interchanges. If P_{ik} is the total interchange specified for area k , then the equation for the area k slack machine is replaced by

$$P_{ik} = \operatorname{Re} \sum_{i=1}^{l_k} E_{pi} (E_{pi} - E_{qi})^* (-Y_{piqi})^* \quad (32)$$

where

- p_i terminal bus in area k for tie line i
- q_i terminal bus outside area k for tie line i
- l_k total number of tie lines emanating from area k .

E_{pi} , p_i voltage magnitude and angle at bus p_i

Y_{piqi} the element in the admittance matrix corresponding to tie line i .

The area slack bus equations in the Jacobian matrix are replaced by

$$\delta P_i = \sum_{i=1}^{l_k} \left[\frac{\partial P_i}{\partial \theta_{p_i}} \delta \theta_{p_i} + \frac{\partial P_i}{\partial E_{p_i}} E_{p_i} \frac{\delta E_{p_i}}{E_{p_i}} + \frac{\partial P_i}{\partial \theta_{q_i}} \delta \theta_{q_i} + \frac{\partial P_i}{\partial E_{q_i}} E_{q_i} \frac{\delta E_{q_i}}{E_{q_i}} \right] \quad (33)$$

(The subscript k from P_i has been removed for brevity)

$$\text{where } \frac{\partial P_i}{\partial \theta_{q_i}} = f_{p_i} a_i - e_{p_i} b_i \quad (34)$$

$$\frac{\partial P_i}{\partial E_{q_i}} E_{q_i} = f_{p_i} b_i + e_{p_i} a_i$$

$$\text{with } a_i + j b_i = (e_{q_i} + j f_{q_i}) (G_{piqi} + j B_{piqi})$$

$$\begin{aligned} \frac{\partial P_i}{\partial \theta_{p_i}} &= - \frac{\partial P_i}{\partial \theta_{q_i}} \\ \frac{\partial P_i}{\partial E_{p_i}} &= \frac{\partial P_i}{\partial E_{q_i}} E_{q_i} - 2 E_{p_i}^2 G_{piqi} \end{aligned}$$

$$\delta P_i = P_i (\text{scheduled}) - P_i (\text{actual}) \quad (35)$$

Inclusion of the area control equations in a Newton's power flow program involves some modification in the input and storage of data ordering and triangularization of the Jacobian. For n areas, P_i for $n-1$ areas will determine system interchange, since

$$\sum_{k=1}^n P_{ik} = 0 \quad (36)$$

A P_i equation will in general have a zero diagonal element in the Jacobian matrix. This element must become non-zero before the Gaussian elimination algorithm attempts to divide by the diagonal term. For each area enough buses must be included prior to the P_i equation so that a path may be found from a tie-line terminal bus of the area to the area slack bus. This will insure that the diagonal becomes nonzero before the division takes place.

Adjustment of transformer and phase shifter taps

Representation of LTC transformer

Fig. 1

If node i is regulated by LTC transformer T_1 (with tap t_1), assuming the convention shown in Figure 1, the self and mutual admittances of nodes i and k are given by

$$\begin{aligned} Y_{ik}^0 &= G_{ik}^0 + j B_{ik}^0 = -Y^0 \\ Y_{ki} &= Y_{ki}^0 = t_1 Y_{ik}^0 \\ Y_{ii} &= Y_{ii}^0 + (t_1^2 - 1) Y^0 \\ Y_{kk} &= Y_{kk}^0 \end{aligned} \quad (37)$$

Representation of phase shifting transformer

Fig. 2

If nodes i and k are the terminals of the phase shifting transformer and if the phase shifter is on the i side of the Y^0 admittance (Fig. 2) the admittance relationships are

$$\begin{aligned} Y_{ik} &= -Y^0 e^{j\phi_{ik}} \\ Y_{ki} &= -Y^0 e^{-j\phi_{ik}} \\ Y_{ii} \text{ and } Y_{kk} &\text{ remain unchanged} \end{aligned} \quad (38)$$

An LTC is operated so that the tap is adjusted (within limits) to constrain the voltage to a desired value. For this mode of operation $|E_i|$ is constant and the transformer tap setting t_i should replace it in equation 27 as a variable. Hence, any LTC regulated node i has its voltage $|E_i|$ replaced by t_i as a variable. Incorporating these changes will modify some of the N and L terms in equation 27. For example, if node i is regulated by LTC transformer having tap setting t_i and the transformer is located in branch (i,k) , N_{ki} and L_{ki} terms would be replaced by terms C_{ki} and D_{ki} given by

$$\begin{aligned} C_{ki} &= \frac{\partial P_k}{\partial t_i} t_i \\ D_{ki} &= -\frac{\partial Q_k}{\partial t_i} t_i \end{aligned} \quad (39)$$

and the corresponding $\frac{\partial E_i}{\partial t_i}$ would be replaced by $\frac{dt_i}{t_i}$

Because the variable t_i is not a node variable in the same sense as E_i , C_{ki} and D_{ki} are zero when no branch (i,k) exists for the network as well as when branch (i,k) does not represent the LTC transformer that is regulating node i . Each LTC regulated-node column in equation 27 thus usually has only one nonzero off-diagonal C_{ki} and/or D_{ki} term. When LTC limits are encountered during the course of a solution LTC's are changed from variable to fixed types.

Terms C and D can be calculated from

$$\begin{aligned} C_{ki} &= (a_i^0 e_k + b_i^0 f_k) t_i = N_{ki} \\ D_{ki} &= (a_i^0 f_k - b_i^0 e_k) t_i = L_{ki} \\ a_i^0 + j b_i^0 &= (v_i + j f_i) (G_{ki}^0 + j B_{ki}^0) \\ Y_{ki}^0 &= (G_{ki}^0 + j B_{ki}^0) \\ C_{ii} &= -2 G_{ki}^0 E_i^2 t_i^2 + (a_k^0 e_i + b_k^0 f_i) t_i \\ D_{ii} &= 2 B_{ki}^0 E_i^2 t_i^2 + (a_k^0 f_i - b_k^0 e_i) t_i \end{aligned} \quad (40)$$

Phase shifter ϕ_{ik} is typically operated to constrain P_{ik} at a value P_{ik}^{reg} . Since P_{ik} is not a regular problem variable ϕ_{ik} enters as an extra problem variable, and the linearized relation $\Delta P_{ik} = P_{ik}^{reg} - P_{ik}$ is an additional constraint equation. The resulting linearized Newton equations will appear as in (41).

$$\begin{bmatrix} \Delta P \\ \Delta Q \\ \Delta P_{ik} \end{bmatrix} = \begin{bmatrix} H & N & E \\ J & L & F \\ H_{ik,i} & H_{ik,k} & N_{ik,i} & N_{ik,k} & E_{ik,ik} \end{bmatrix} \begin{bmatrix} \Delta \delta \\ \frac{\Delta E}{E} \\ \Delta \phi_{ik} \end{bmatrix} \quad (41)$$

$$\begin{aligned} E_{i,ik} &= \frac{\partial P_i}{\partial \phi_{ik}} \\ P_{i,ik} &= \frac{\partial Q_i}{\partial \phi_{ik}} \end{aligned} \quad (42)$$

The terms in i and k rows of the Jacobian matrix are calculated using the admittances given in (38)

The off diagonal terms in the row of the P_{ik}^{reg} constraint equation are

$$\begin{aligned} H_{ik,k} &= -H_{ik,i} = H_{ik} \\ N_{ik,k} &= N_{ik} \\ N_{ik,i} &= N_{ik} + 2 E_i^2 G_{ik}^0 \end{aligned} \quad (43)$$

The terms in the column of the P_{ik}^{reg} constraint equation are calculated using (42). The off-diagonal terms are

$$\begin{aligned} E_{i,ik} &= -H_{ik} \\ F_{i,ik} &= J_{ik} \\ E_{k,ik} &= H_{ki} \\ F_{k,ik} &= J_{ki} \end{aligned} \quad (44)$$

and the diagonal term is

$$E_{ik,ik} = E_{i,ik}$$

Decoupled Load Flow

In a practical power system, the coupling between "P- δ " and "P-E" components is relatively weak which is reflected in the elements of the submatrices N and J in equation 27 being small compared to those in H and L . This permits "decoupling" (solving separately) the P- δ and Q-E problems by neglecting the elements of N and J . Two separate sets of equations thus obtained are:

$$\Delta P = H \Delta \delta \quad (45)$$

$$\Delta Q = L \frac{\Delta E}{E} \quad (46)$$

It has been found useful to rearrange equation 46 by dividing ΔQ by E , since it substantially reduces the nonlinearity of the Q-E problem.

$$\frac{\Delta Q}{E} = L' \frac{\Delta E}{E} \quad (47)$$

An approach which works well is to construct equation 45 for $\Delta \delta$, and use the updated δ 's in constructing and then solving (47) for ΔE . Each of these construction/solutions can be performed alternately in the same storage area. In the form presented, the decoupled method has been claimed to converge at least as reliably as the formal Newton version (27). For convergence to practical accuracies, it usually takes a similar number of iterations. The rate of convergence in the early stages of the solution is faster than that of the formal Newton approach, although the decoupled method does not subsequently have the quadratic property needed for rapid high-accurate solution. The reliability of the method is high.

Fast decoupled method

Using the approximations

$$\cos \delta_{ik} \approx 1, \quad G_{ik} \sin \delta_{ik} \ll B_{ik}, \quad Q_i \ll B_{ii} E_i^2$$

equations 45 and 46 can be reduced to

$$\Delta P = [B' E] \Delta \delta \quad (48)$$

$$\Delta Q = [B'' E] \frac{\Delta E}{E} \quad (49)$$

The elements of B and B'' are the elements of $[-B]$, E is a diagonal matrix.

The decoupling process is completed by:

- Omitting from B' the shunt reactances and off-nominal in-phase transformer taps
- Omitting from B'' the angle shifting effects of phase shifters
- taking the left-hand E terms in (48) and (49) on to the left-hand sides of the equations and then in (48) removing the influence of NVAR flows on the calculation of $\Delta \delta$ by setting all the right hand E terms to 1 p.u.
- neglecting series resistances in calculating the elements of B

The final equations thus become

$$\frac{\Delta P}{E} = B' \Delta \delta \quad (50)$$

$$\frac{\Delta Q}{E} = B'' \Delta E \quad (51)$$

The method has been found to work just as well if phase shifters are left out of B' also. Consequently, both B' and B'' are always symmetrical, and their constant sparse upper triangular factors are calculated and stored once only at the beginning of the solution.

APPENDIX A-2
STOCHASTIC/PROBABILISTIC LOAD FLOW

Introduction

Currently, load flow analysis commonly performed as part of the system planning function is primarily deterministic in nature; that is, each load flow calculation solves for a specific set of branch flows given a unique set of input parameters (system configuration, system parameters and generation and load schedule). Critical planning decisions are then made on the basis of a limited number of such load flow cases combined with considerable human judgment.

Yet it is intuitively obvious that since the several load flow input parameters are characteristically uncertain in nature, the load flow solution is an inherently stochastic one, and one in which the resultant branch flows are more properly represented by a range of possible values, or mathematically by a probability distribution function. Such a solution would provide the planner with a clearer indication of the reliability of the transmission system being analyzed, and thus greater confidence in his planning decisions.

Available Methodologies

To date, methods of including these uncertainties into the load flow analysis have focused on adapting statistical techniques toward treating uncertainties in the node data (i.e. load/generation schedules.) Hence, given a specific network configuration and line parameters, and net load data at each system node expressed in terms of a probability distribution function, these methods would express the resulting network branch flows also in terms of a probability distribution function.

More specifically, methods have been developed by a) Borkowska, b) Dopazo, Klitin and Sasson and c) Heydt, which apply different statistical mathematics to solve the problem as defined above; Borkowski for the dc case, and Dopazo, Klitin and Sasson and Heydt for the ac case. Although each method has been applied to test systems by the authors, the absence of sufficiently wide use and application by planning engineers to analyze real-life large-scale systems does not allow conclusive statements to be rendered regarding the relative preferability of any of the three methods or the potential adaptability of any one method to large load-flow models.

Observations

1. The load flow problem is stochastic in nature; that is, several of its input parameters are subject to uncertainty, and hence its output (branch flows) is best expressed as a set of possible values with associated frequencies of occurrence, or a probability distribution function.
2. The uncertainties in the formulation of the load flow analysis input parameters are caused by the following factors:
 - load forecast uncertainties due to influences of business, economics, conservation, etc.;
 - load variability due to weather conditions and load management measures;
 - delays in the installation of new generation and transmission facilities;
 - unavailability (forced outage, maintenance) of installed generator and transmission facilities;
 - uncertainty in fuel prices and fuel availability;
 - application of new technologies in power generation and transmission.
3. A comprehensive, workable stochastic load flow would:
 - provide the planning engineer with a flexible tool to effectively compare planned transmission systems on a probabilistic basis;
 - lend greater overall credibility to the load flow results by enclosing the power flow demand pattern to which each branch will be subjected, instead of only a typical value as in the conventional load flow;
 - provide for an overall reduction in computer usage and engineering manpower requirements since although the data requirements for each run will be significantly greater than for a conventional load flow, each run will represent the results of several conventional load flows.
4. Three independent stochastic load flow models have been developed to solve for possible ranges of transmission branch flows due to uncertainty in net nodal data. Further information is desired regarding the applicability of each of these methods to analyze large power systems.

APPENDIX B TRANSIENT STABILITY

Synchronous Machine Representation

The basic 2 axis equations of a synchronous machine as formulated by Park can be summarized, assuming two rotor circuits on each axis, as follows:

$$\dot{V}_{fd} = x_{fd} i_{fd} - x_{ad} i_d + x_{fld} i_{ld} \quad (1)$$

$$\dot{V}_d = x_{ad} i_{fd} - x_d i_d + x_{ad} i_{ld} \quad (2)$$

$$\dot{V}_{ld} = x_{fld} i_{fd} - x_{ad} i_d + x_{lld} i_{ld} \quad (3)$$

$$\dot{V}_q = -x_q i_q + x_{aq} i_{lq} + x_{aq} i_{2q} \quad (4)$$

$$\dot{V}_{lq} = -x_{aq} i_q + x_{llq} i_{lq} + x_{l2q} i_{2q} \quad (5)$$

$$\dot{V}_{2q} = -x_{aq} i_q + x_{l2q} i_{lq} + x_{22q} i_{2q} \quad (6)$$

$$e_{fd} = \frac{1}{\omega_0} p \dot{V}_{fd} + r_{fd} i_{fd} \quad (7)$$

$$e_d = \frac{1}{\omega_0} p \dot{V}_d - \frac{\omega}{\omega_0} V_q - r_a i_d \quad (8)$$

$$0 = \frac{1}{\omega_0} p \dot{V}_{ld} + r_{ld} i_{ld} \quad (9)$$

$$e_q = \frac{1}{\omega_0} p \dot{V}_q + \frac{\omega}{\omega_0} V_d - r_a i_q \quad (10)$$

$$0 = \frac{1}{\omega_0} p \dot{V}_{lq} + r_{lq} i_{lq} \quad (11)$$

$$0 = \frac{1}{\omega_0} p \dot{V}_{2q} + r_{2q} i_{2q} \quad (12)$$

$$T_e = \dot{V}_d i_q - \dot{V}_q i_d \quad (13)$$

Although a synchronous machine can be represented in much more detail by assuming additional rotor circuits on each axis, the limited amount of data supplied by a manufacturer do not generally permit any further detail. However, extensive studies have shown that the equations presented here are sufficient for an accurate representation of a synchronous machine in a stability program. The three amortisseur circuits represent the eddy current paths in the solid iron rotor of a round rotor steam-turbine generator. In the case of a laminated rotor machine (such as a hydraulic turbine generator or synchronous motor) data for only one amortisseur circuit in the quadrature circuit may be available. For this type of machine, it is customary to consider the q axis transient reactance to be the same as the q axis synchronous reactance.

Although equations 1-13 can be solved directly, the numerical solution of the differential equations requires a very small integration step resulting in high computational costs. In stability studies, the $p \dot{V}_d$ and $p \dot{V}_q$ terms can generally be neglected without sacrificing

accuracy significantly. This permits a much larger time step in the numerical integration thereby effecting considerable saving in the computational cost.

Depending on the nature of the study various other simplifications are also in order. Generally machines near a disturbance are represented by a detailed model. Whereas machines remote from the disturbance may be represented by a simple model. Machines at intermediate locations may be represented by a model of intermediate complexity.

After applying various simplifications, the following machine models can be derived. They all use the standard machine data supplied by the manufacturers and which also can be determined from tests. The models are numbered in the order of increasing detail. In all of the models, the $p \dot{V}_d$ and $p \dot{V}_q$ terms are neglected.

Model 5

This model has two rotor circuits in each axis - the field circuit plus one amortisseur in the d-axis and two amortisseurs in the q-axis. It is the most complex model now available in large scale stability programs, and uses all the presently defined data. Of the various forms in which this model may be presented, the following approximate form seems to be most elegant.

$$T_{do}' p e_q' = e_f - (x_d - x_d') i_d - e_q' \quad (14)$$

$$T_{d0}'' p e_q'' = e_q' - (x_d' - x_d'') i_d - e_q'' \quad (15)$$

$$e_q' = e_q + r_a i_q + x_d' i_d \quad (16)$$

$$e_q'' = e_q + r_a i_q + x_d'' i_d \quad (17)$$

$$T_{q0}' p e_d' = (x_q - x_q') i_q - e_d' \quad (18)$$

$$T_{q0}'' p e_d'' = e_d' + (x_d' - x_d'') i_q - e_d'' \quad (19)$$

$$e_d' = e_d + r_a i_d - x_q' i_q \quad (20)$$

$$e_d'' = e_d + r_a i_d - x_q'' i_q \quad (21)$$

$$T_e = e_d' i_d + e_q' i_q + (x_q' - x_d') i_d i_q \quad (22)$$

Model 4

This model has one amortisseur circuit in each axis and a field circuit. The equations are

Equations 14-17 and 22 unchanged

$$T_{q0}' p e_d' = (x_q - x_q') i_q - e_d' \quad (23)$$

$$e_d' = e_d + r_a i_d - x_q' i_q \quad (24)$$

Model 3

This model has a single quadrature axis rotor circuit and a field circuit. The equations are

$$T_{d0}' p e_q' = e_f - (x_d - x_d') i_d - e_q' \quad (25)$$

$$T_{q0}' p e_d' = (x_q - x_q') i_q - e_d' \quad (26)$$

$$e_q' = e_q + r_a i_q + x_d' i_d \quad (27)$$

$$e_d' = e_d + r_a i_d - x_q' i_q \quad (28)$$

$$T_e = e_d' i_d + e_q' i_q + (x_q' - x_d') i_d i_q \quad (29)$$

Model 2

This model has no amortisseur circuits and only the field circuit is represented. The equations are

$$T_{d0}' p e_q' = e_f - (x_d - x_d') i_d - e_q' \quad (30)$$

$$e_q' = e_q + r_a i_q + x_d' i_d \quad (31)$$

$$0 = e_d + r_a i_d - x_q' i_q \quad (32)$$

$$T_e = e_q' i_q + (x_q - x_d') i_d i_q \quad (33)$$

Model 1

This is the classical transient stability model. This uses a constant voltage magnitude behind transient reactance.

The reactances and time constants appearing in the above equations are expressed as using the usual notations.

$$x_d'' = x_d - \frac{x_{ld} x_{ad}^2 - 2x_{fld} x_{ad}^2 + x_{ffd} x_{ad}^2}{x_{ld} x_{ffd} - x_{fld}^2} \quad (34)$$

$$x_q'' = x_q - \frac{x_{22q} x_{aq}^2 - 2x_{l2q} x_{aq}^2 + x_{l1q} x_{aq}^2}{x_{22q} x_{l1q} - x_{l2q}^2} \quad (35)$$

$$x_d' = x_d - \frac{x_{ad}^2}{x_{ffd}} \quad (36)$$

x_q' ($=x_q''$ in the case of salient pole machines where only one quadrature axis amortisseur is represented).

$$e_q = e_q' - \frac{x_{d2q}^2}{x_{l1q}} \quad (37)$$

$$T_{do}' = \frac{x_{ffd}}{\omega_0 r_{fd}} \quad (38)$$

$$T_{q0}' = \frac{x_{l1q}}{\omega_0 r_{l1q}} \quad (39)$$

$$T_{do} = \frac{1}{\omega_o F_{1d}} \left(x_{11d} - \frac{x_{r1d}^2}{x_{rfd}} \right) \quad (40)$$

$$T_{qo} = \frac{1}{\omega_o F_{2q}} \left(x_{22q} - \frac{x_{12q}^2}{x_{11q}} \right) \quad (41)$$

The equation of motion is given by

$$\frac{H}{\pi f_o} p^2 \delta + T_i - T_e - K_d \frac{p\delta}{\omega_o} \quad (42)$$

The constant K_d may be used to approximately represent any damping not accounted for by the machine equations.

An accurate representation of a synchronous machine especially a solid iron turbine generator requires representation of a large number of rotor circuits on both axis to account for the effects of rotor ω current transients on machine performance. However, the complexity of such a model will limit its use only to specialized studies. Recently efforts have been directed towards establishing simplified machine models using modified values for the machine parameters to resemble the response characteristics of the complex model. It has been shown that the calculated responses from such a complex model can be approached very closely to those obtained from test.

Conventional machine parameters calculated or obtained from tests on the basis of a limited number of rotor iron circuits cannot be expected to produce the same responses as those from a complex model using a large number of circuits. However, it is possible to adjust the parameters of the simpler models such that the frequency response of the impedance elements of the simpler and the complex models would be similar. The simpler models with these adjusted parameters would then be expected to be adequate for studies requiring an accurate machine model. Work has also been reported on the development of procedures of obtaining machine models from frequency response tests of actual machines. The procedure is similar to that of obtaining simpler models from a complex one. Instead of calculating the frequency responses of the complex model, where all the relevant data may not be available, the responses are obtained from direct measurements. Both methods have been shown to produce similar results. It has been found that, in general, as far as the basic reactance values (such as x_d , x_q , x_d'

etc.) are concerned the difference between the standard data as calculated on the basis of ANSI definitions and the adjusted data is not significant. However, in the case of time constants, the difference is quite noticeable. It may be noted that the time constants for the adjusted data are not those usually associated with the exponential decay of the direct or quadrature axis voltages. Studies performed using the simpler and complex models and comparison with test results have shown that the results obtained from simpler models using the adjusted data are generally more accurate than those obtained using standard machine data. Although model 5 with adjusted data has an overall edge in accuracy over other less elaborate models the much simpler model 3 with adjusted data can produce results of comparable accuracy.

Saturation

In a stability study of a complex system, a rigorous treatment of machine saturation is impractical. Saturation has generally been accounted for in one of two ways, both approximate. While using one of the more complex machine models, it is convenient to account for saturation by adjusting the values of x_{ad} and x_{aq} depending on the state of machine saturation. A saturation factor is calculated from the no-load saturation curve and the corresponding air-gap line. The voltage behind the potier reactance or leakage reactance is used for this purpose. The direct and quadrature axis quantities are assumed to be affected equally due to saturation. It may be noted that in this method of accounting for saturation, all the reactance values and time constants in the machine differential equations are affected by saturation and must be adjusted at each step of integration. However, the effect of saturation on the transient and subtransient reactances is not significant and, therefore, these may be left unchanged in the voltage equations that are solved along with the network equations.

In using the simpler machine models 2 and 3, it is customary to account for saturation by subtracting a quantity, proportional to the degree of saturation, from the right hand side of differential equations (Eqs. 25 and 30) representing the change in the direct axis rotor flux linkage.

Representation of Loads

In the first stability programs, loads were represented by constant impedances so that network driving point and transfer impedances as seen from the generators between switching times would remain constant. In the stability analysis of earlier systems, this was perhaps a valid assumption since stability was known to be relatively insensitive to transient responses of loads in those systems. Also the modest computing facilities did not allow representation of loads in any further details. This is still the way loads are represented in some of present day stability studies, where the loads are known to be predominantly of impedance types. However, the importance of proper representation of loads in the stability studies of large interconnected systems is recognized and most modern transient stability programs have provision for individual representation of bus loads as functions of bus voltage, bus frequency or both. Although the response of nearly all loads to voltage changes can be represented by some combination of constant impedance, constant current, and constant MVA devices, the actual proportion in which these are distributed in a composite load is not always known. Even if this can be estimated for a system during the steady state, the load characteristic is likely to change in the transient state following a major system disturbance.

The general non-linear load representation adopted in most stability programs is of the form

$$P = K + K_1 E + K_2 E^2 \quad (43)$$

$$Q = K_3 + K_4 E + K_5 E^2 \quad (44)$$

The three terms are corresponding to constant MVA, constant current and constant impedance parts respectively. If desired, the three terms can be combined into one as follows:

$$P = P_o E^{n1} \quad (45)$$

$$Q = Q_o E^{n2} \quad (46)$$

where n might theoretically vary between 0 and 3.

In the absence of a more complete information on the load behavior, either method is acceptable during the range of voltages encountered during machine angular swings. However, the representation using equations 43 and 44 has the disadvantage that the presence of the constant terms does not allow them to pass through a zero P or Q point for zero voltage. This can be overcome by allowing the load to change to a constant impedance type when the bus voltage magnitude falls below a minimum. The load would be treated as a constant impedance ($P \propto E^2$, $Q \propto E^2$) until the bus voltage rises above the minimum at which point the original representation would be restored.

Similar arrangement is also desirable in the alternative representation (Equations 45, 46).

The dependence of loads on frequency can be accounted for in a similar way. For example, to allow for load dependence on both voltage and frequency equations 45 and 46 can be modified as follows:

$$P = P_o \omega^{n1} E^{n1} \quad (47)$$

$$Q = Q_o \omega^{n2} E^{n2} \quad (48)$$

Loads involving inertia may require special representations that include the inertia effects depending on their influence on the dynamic performance of the system. In the case of large industrial type induction or synchronous motor, since they form a substantial portion of the total load and since their number is usually limited, it is practical as well as desirable to employ a detailed mathematical representation in terms of d - q axis, which includes all the transient and inertial effects accurately. If the stability of these motors themselves are under investigation then their representation in detail becomes essential. Synchronous motor loads when they require special representation can be represented in the same way as a synchronous generator. The representation of induction motor require some discretion. The representation of the machines stator transients is impractical in an overall system stability study. The value of the effective rotor time constant of a motor is a function of external system parameters as well as of motor constants. In many power systems, the effective rotor time constant is small. When this is true, it is possible to neglect both rotor and stator time constants. The induction motor can then be represented by the familiar steady state equivalent circuit with appropriate values of reactance, resistance and slip. The equivalent circuits normally used for stability studies are shown in Figures 1A and 1B. The impedance

Fig. 1A

Fig. 1B

Most induction motors are designed with rotor slot configurations which result in significant variations of rotor resistance and leakage reactance with slip. When such motors experience large transient slip, the equivalent circuit of Figure 1B should be used. The average system frequency at the terminals of each motor during a time interval is calculated and the difference between the motor nominal rotor slip and the system frequency slip is used in the induction motor equivalent circuit to calculate the new electrical torque at the end of the time interval.

When the motor and system parameters are such that the effective rotor time constant should be considered, the induction motor transient behavior can be computed using transient equations. Starting with the motor's differential equations referred to synchronously rotating axes, and neglecting stator transients, the following equations can be derived

$$p e' = -[e' + j(\pi - \alpha') I_B] / T_{do}' - j w s e' \quad (49)$$

$$E_t = -(R_s + j \omega' X_s) I_B + e' \quad (50)$$

where E_t = terminal voltage

R_s = stator resistance

X_s = blocked rotor reactance

ω = open-circuit reactance

T_{do}' = open-circuit rotor time constant

w = stator electrical angular velocity

s = slip, per unit

e' = rotor voltage proportional to rotor flux linkage

I_B = stator current, out of the machine

Two other equations that are necessary to complete the induction machine modelling are

$$T_e = \text{Re}(e' I_B) \quad (51)$$

$$\frac{ds}{dt} = \frac{\pi f_o}{H} (T_e - T_L) \quad (52)$$

The load torque applied to the motor shaft may have both speed and time dependent components. The speed dependent function may have the form

$$T_L = A + B \omega_r + C \omega_r^2 \quad (53)$$

A, B, C are arbitrary constants and ω_r is rotor speed in per unit. The necessity of using a very small integration time step due to small rotor time constant may prohibit the representation of rotor transients in a large scale stability study. The use of one of the

equivalent circuits would permit a much larger time step. However, the calculation of network and machine terminal conditions becomes more involved. Therefore, unless the rotor time constants are very small and a very small time step is anticipated, the induction machine model representing rotor transients (Eqs 49-52) would be a more logical choice since, in addition to increased accuracy, this would result in a more efficient network solution.

Synchronous Condensers

Synchronous condensers generally have low inertia constants. When the effects of inertia is to be included, the synchronous condensers may be represented as synchronous machines. However, the low inertia constants can produce high-amplitude swings at relatively high frequencies. Therefore, it may be desirable to eliminate this difficulty by representing synchronous condensers as inertialess, lossless device which must operate at a terminal power factor of zero. Therefore, only the d axis impedances are of interest. During the stability calculations the position of the direct axis is varied such that the phasor position of the internal voltage and the terminal voltage are the same.

Excitation Systems

The basic representations for various types of excitation systems as proposed by the IEEE Working Group have been adopted for many stability programs. These have been generally satisfactory and flexible enough to represent a wide range of excitation system types. The Working Group has defined four excitation system types to be used in computer representations. These are described in detail in reference. Only the Type 1 excitation system is reproduced here, since this will be used to illustrate dynamic stability calculations later. It may be noted that the type 1 excitation system is representative of the majority of modern systems now in service and presently being supplied. Many other systems can also be adequately represented by a proper adjustment of the constants

Fig. 2

In the absence of a standard representation of supplementary stabilizing signals, a general representation as shown in Figure 3 may be used. Inputs from machine speed, bus frequency, electrical power, and terminal voltage may be used separately or in combination.

Fig. 3

Prime-Movers

The basic models for speed-governing systems and turbines suitable for power system stability studies have been presented by the IEEE Working Group. A detailed discussion may be found in reference. The general models for speed-governing systems for steam turbine and hydro systems are shown in Figures 4A and 4B respectively.

Fig. 4A

Fig. 4b

The speed-governing models of Figure 4 may be used to represent either a mechanical-hydraulic system or an electro-hydraulic system by means of an appropriate selection of parameters.

A general model for steam turbine systems suitable for use in stability calculation is shown in Figure 5.

Fig. 5

All of the commonly encountered steam system configuration may be represented by a proper evaluation of the parameter values. The effect of boiler response and fast valving can be included by inserting multipliers as shown.

An ideal hydroturbine can be represented for stability studies, as shown in Figure 6.

Fig. 6

It may be noted that this representation can be obtained from the

general model of Figure 5 by putting $K_1 = -2$, $K_3 = 1$, $T_5 = \frac{T_w}{2}$ and all other constants equal to zero.

Relay Representation

The basic relay types normally represented in a large scale stability program are distance relay, overcurrent relay, out-of-step relay, overpower relay and underfrequency relay. A few other types are also occasionally represented. The variables that are needed by the relay simulation routines are the bus voltage, bus frequency, line current and power flow, and apparent line impedance. The apparent impedance seen by an impedance relay is calculated by dividing the voltage at the bus near the relay by the current flowing in the line away from the bus near the relay. Bus frequency deviation is based on the rate of change of voltage angle. The calculation procedure to simulate the operation of a three zone distance relay is illustrated. The calculation procedures to simulate other types of relays are similar. The three units of the three zone distance relay are adjusted independently. A directional unit is either provided in the relay, as in the impedance-type distance relay, or is inherent in the operating characteristics, as in the mho-type distance relay. The operating characteristics of these two types of relays are shown in Figures 7a and 7b.

Fig. 7

During a system disturbance and following the switching operations, power swings will occur on the transmission system. During the step-by-step calculations, the apparent impedance is calculated and compared to the operating characteristics of the relay. For this purpose, the impedance values can be plotted on the characteristic diagram of the relay - as shown in Figure 7b. From the coordinates of the centers of the circles for each zone and the apparent impedance value, the distances of the impedance point from the centers of the circles are calculated. These are compared with the radii of the circles to establish the zone in which the impedance point falls at a particular instant of time. If the apparent impedance is in zone 1, an immediate switching operation is initiated. If the impedance is within zone 2 and 3 or zone 3, the contacts of the associated units are closed and a timer is started.

The timer is advanced during the transient calculations by the time step. When the timer reaches the time setting for zone 2 or 3, and the corresponding contacts are closed, a switching operation is initiated. The switching time is determined by adding the inherent relay and the circuit breaker time. A dropout circle is defined for resetting the relay. The relay is reset instantly whenever the breaker is opened or whenever the impedance moves outside the dropout circle for zone 2 or 3 before the switching operation is initiated.

Transient Stability Calculation

In a transient stability study, the network is first brought into load flow balance. From the known terminal conditions of the generators and other machines represented in detail the magnitude E_t and angle θ of the terminal voltages with respect to a reference axis, and I_q the current feeding into the network, the internal voltages i.e. the voltages behind transient and subtransient reactances are determined. The position of quadrature axis of the generators and other synchronous machines are determined from a fictitious voltage behind the quadrature axis synchronous reactance.

In the transient state following a disturbance, the generator terminal voltages and electrical power output do not remain constant. At each time step, the machine internal voltages and angle are prescribed, and power injected into system are the unknowns that are to be determined by the load flow calculations. Accordingly, the load flow algorithm must be modified.

The calculation procedure that is most efficient in a particular study can be selected from a consideration of the study requirement.

Fig. 8

If during the swing curve calculation the information at every node is required at each time step, it is advantageous to preserve the identity of all the nodes and employ an iterative solution technique. The Gauss-Seidel iterative method is used in most stability calculations.

of this type. In many stability studies, on the other hand, information concerning the buses other than the generator buses and a limited number of other buses are not required. This permits the use of a more efficient calculation technique employing the reduced Y or Z matrix. Both Gauss-Seidel iterative method and the matrix method will be reviewed here. Synchronous machines will be assumed to be represented by model 3. Calculation techniques for other machine models are similar. Transient saliency is assumed to be present.

In the synchronous machine equations, the currents and voltages are expressed in terms of the individual d-q axis reference frame. It is necessary to express these quantities in terms of a common network (D,Q) reference frame in order to obtain a network solution. The transformation relationship is given by:

$$\begin{bmatrix} d \\ q \end{bmatrix} = \begin{bmatrix} \sin \delta & -\cos \delta \\ \cos \delta & \sin \delta \end{bmatrix} \begin{bmatrix} D \\ Q \end{bmatrix} \quad (54)$$

and by its inverse

$$\begin{bmatrix} D \\ Q \end{bmatrix} = \begin{bmatrix} \sin \delta & \cos \delta \\ -\cos \delta & \sin \delta \end{bmatrix} \begin{bmatrix} d \\ q \end{bmatrix} \quad (55)$$

Due to the presence of saliency, it is convenient to define a fictitious voltage behind one of the transient reactances in the network calculation. This voltage is corrected in an iterative manner in the course of the calculation. If the fictitious voltage is assumed to be the voltage behind the q-axis transient reactance, the voltage is calculated at the start of the step-by-step calculation from:

$$E = E_t + (x_d + j x_q') I_t \quad (56)$$

The d and q axis voltages corresponding to the rotor flux linkages ψ_d and ψ_q are given by equations 27 and 28. These are held constant during the network solution. The changes in these voltages are governed by the differential equations 25 and 26.

During the network calculation, the iterative correction of the fictitious voltage E is achieved through the following equations.

$$E_d = e_d' \quad (57)$$

$$E_q = e_q' + (x_q - x_d') I_d \quad (58)$$

The corrected values of E_d and E_q are expressed in network reference frame and the network solution is repeated. Under normal circumstances the convergence is very quick. The iterative procedure for the voltage correction is shown in Figure 9.

Fig. 9

In the nodal iterative method, the general equation for determining the bus voltages for power flow calculation is given by:

$$E_i = \frac{-\sum Y_{ik} E_k + (P_{Li} - jQ_{Li})/E_i^*}{Y_{ii}} \quad (59)$$

The terms $(P_{Li} - jQ_{Li})/E_i^*$ represents the load current at bus i when the load is represented as constant power. For constant current load representation this term would be replaced by $I_{Li} \angle \phi_i - \theta_i$ where ϕ_i is the power factor angle and θ_i is the angle of the voltage with respect to the reference. If the load is represented by a constant impedance equation 59 reduces to:

$$E_i = \frac{-\sum Y_{ik} E_k}{Y_{ii} + Y_{i0}} \quad (60)$$

where Y_{i0} is the static admittance to ground representing the load. When bus i is a generator bus, Y_{ii} will include the machine equivalent admittance. Also, the expression within the summation sign will contain a term corresponding to the machine internal voltage (the fictitious voltage when saliency is considered) which is held constant during the iterative solution.

Equation 59 is quadratic in E_i , therefore, an iterative procedure is required to solve for the system bus voltages. Equation 60 is, however, linear and it may be more expedient to obtain the solution by a noniterative Gaussian elimination technique exploiting the sparsity of the matrix.

The same non-iterative Gaussian elimination technique can be applied to obtain an approximate solution of equation 59 during a large part of the swing curve calculation. The variations in magnitude and angle of bus voltages from one time step to the next are usually small except following a large disturbance. Hence the term $(P_{Li} - jQ_{Li})/E_i^*$ (or $I_{Li} \angle \phi_i - \theta_i$) in equation 59 can be replaced by a constant term calculated from the voltage of the previous time step. The equation then reduces to the linear form of equation 60 and the solution can be obtained in the same way.

Once the voltage solution is obtained, the line currents and the machine current can be calculated.

Often in a large scale stability study, the information concerning majority of the nongenerator buses is not required. Generally, the generator buses, the buses involved in switching operations, the buses where non-linear loads are to be represented, and the buses where voltages are to be monitored need to be retained. All other nodes can be eliminated resulting in a simplification in the calculations. Also many small generators and generators remote from the disturbance area need not be represented in the usual way. They can be converted to negative loads and the buses eliminated. The elimination of the buses can be carried out most advantageously during the assembly of the Y matrix. As each bus is included in the matrix, it is eliminated if the bus is not to be retained in the final matrix for stability study. After the reduction is completed, the network equation can be written in the following matrix form:

$$\begin{bmatrix} I_G \\ I_L \\ I_P = 0 \\ I_M = 0 \end{bmatrix} = \begin{bmatrix} Y_{GG} & Y_{GL} & Y_{GP} & Y_{GM} \\ Y_{GL} & Y_{LL} & Y_{LP} & Y_{LM} \\ Y_{GP} & Y_{LP} & Y_{PP} & Y_{PM} \\ Y_{GM} & Y_{LM} & Y_{PM} & Y_{MM} \end{bmatrix} \begin{bmatrix} E_G \\ E_L \\ E_P \\ E_M \end{bmatrix} \quad (61)$$

The subscripts correspond to

G buses corresponding to the generator internal voltages

L load buses

P buses involved in switching operation

M buses where voltages are to be measured

The rows and columns corresponding to the metering axes are eliminated. Since $I_M = 0$

$$E_M = -Y_{MM}^{-1} (Y_{GM} E_G + Y_{LM} E_L + Y_{PM} E_P)$$

Although shown here in matrix form, the elimination should be performed by a series of single row and column substitutions. The information necessary to reconstruct the voltages E_M are saved since voltages are to be calculated for these buses.

A second reduction is made after the switching operations have been performed following the above procedure, and information necessary to reconstruct the voltages E_M are saved. The resulting matrix equation is

$$\begin{bmatrix} I_G \\ I_L \end{bmatrix} = \begin{bmatrix} Y_{GG} & Y_{GL} \\ Y_{GL} & Y_{LL} \end{bmatrix} \begin{bmatrix} E_G \\ E_L \end{bmatrix} \quad (62)$$

where the elements of Y have been modified from those in (61) due to the reductions performed. When all loads are represented by constant impedances equation 62 can be further reduced to:

$$I_G = Y_{GG}' E_G \quad (63)$$

Since $I_L = 0$

In this case, the matrix Y_{GG} represents the admittances between the generator buses behind the transient reactances (x_d' for the formulation developed here using model 3). Although the generator currents are obtained by direct multiplication as shown in equation 63, an iterative correction for E_G , as illustrated in Figure 9, is required due to transient saliency. With E_G corrected, the power output of the generators are given by:

$$P = \text{Re} (E_G Y_{GG}^* E_G^*) \quad (64)$$

The power output can also be obtained from equation 29.

When non-linear load are considered, it is convenient to rearrange equation 62 into the form of equation 65.

$$\begin{bmatrix} I_G \\ E_L \end{bmatrix} = \begin{bmatrix} Y_{GG}' & - \\ -Z_{LL}' Y_{GL} & -Z_{LL}' \end{bmatrix} \begin{bmatrix} E_G \\ I_L \end{bmatrix}$$

Here again, a series of single row and column operations may be preferred to matrix multiplication and inversion as suggested in the above equation.

The iterative procedure that can be used to solve equation 65 is shown in Figure 10. Once the power outputs are known, the machine rotor angles can be calculated from the equations of motion.

The complete transient stability calculation involves the solution of the differential equations describing the synchronous and induction machines, excitation system control and prime mover control alternating with the network solution. Although any standard numerical technique can be used for the solution of the differential equations, most large scale stability programs use the modified Euler method because of its speed and acceptable accuracy. Other more accurate methods e.g. Runge Kutta and Predictor Corrector methods tend to be prohibitively time consuming in large system studies.

However for specialized studies e.g. investigating the effects of a particular machine model or a particular control system where the complete system is of a reduced order, one of the more accurate methods is recommended.

APPENDIX C-1
DYNAMIC STABILITY CALCULATION

State Space Representation of Power Systems

In dynamic stability analysis through a state-space approach, the system equations are first linearized about an operating point and expressed in the form

$$\dot{x} = Ax \quad (1)$$

where x is the vector of the state variables and A is a matrix of constant coefficients, called the coefficient matrix. For asymptotic stability the eigenvalues of A must have negative real parts.

While the eigenvalues of the coefficient matrix A can be obtained by standard techniques, in a complex system analysis the formation of the matrix can be a major task. A method which has been found most useful in forming the coefficient matrix of a large power system when machines are represented in detail along with their control systems is described here. This method of forming the coefficient matrix also facilitates eigenvalue sensitivity analysis.

Although the individual synchronous machines can be represented by any of the machine models listed earlier, the method is illustrated assuming all synchronous machines represented by model 3 or the classical model (Model 1). However, it will be apparent from the development that any other machine model can be easily incorporated.

The modifications in some of the intermediate steps necessary when induction machines are represented are also pointed out. Any of the standard excitation system representations can be associated with any of the synchronous machines. However, for the sake of simplicity, only the representation shown in Figure 2 of the previous appendix will be considered. This representation is further simplified by combining the regulator and exciter block and ignoring the regulator input filtering time constant (T_R). The prime mover control is not considered, since its inclusion does not present any difficulty. All loads except induction motors are assumed to be represented by constant impedances.

All these simplifications are applied in order not to obscure the basic simplicity and efficiency of the method. Adding the extra complexities and varieties of representation will not render the method impractical; however, the programming burden will be increased considerably.

In a multi-machine system using 2-axis representation, the relationship between the individual machine terminal voltages or currents in terms of the machine reference frame and network reference frame is given by equations of the form of equations 54 and 55 of the previous appendix.

For a system containing n synchronous machines, the voltage relationships are:

$$\begin{bmatrix} e_{d1} \\ e_{q1} \\ e_{d2} \\ e_{q2} \\ \vdots \end{bmatrix} = \begin{bmatrix} \sin \delta_1 & \cos \delta_1 & & \\ -\cos \delta_1 & \sin \delta_1 & & \\ & & \sin \delta_2 & \cos \delta_2 \\ & & -\cos \delta_2 & \sin \delta_2 \\ & & & & \ddots \end{bmatrix} \begin{bmatrix} e_{d1} \\ e_{q1} \\ e_{d2} \\ e_{q2} \\ \vdots \end{bmatrix} \quad (2)$$

or $E_n = T E_m$

The subscripts n and m refer to network and machine reference frame.

Equation 3 when linearized gives

$$\Delta E_n = T \Delta E_m + M \Delta \delta \quad (4)$$

where $M = \begin{bmatrix} -e_{q1} \\ e_{d1} \\ & -e_{q2} \\ & e_{d2} \\ & & \ddots \end{bmatrix}$, and $\Delta \delta = \begin{bmatrix} \delta_1 \\ \delta_2 \\ \vdots \end{bmatrix}$

From equation 4 it also follows that

$$\Delta E_m = T^{-1} \Delta E_n + N \Delta \delta \quad (5)$$

where $N = T^{-1}M = \begin{bmatrix} e_{q1} \\ -e_{d1} \\ & e_{q2} \\ & -e_{d2} \\ & & \ddots \end{bmatrix}$

Similar relationships for the currents are

$$\Delta I_n = T \Delta I_m + \bar{N} \Delta \delta \quad (6)$$

$$\Delta I_m = T^{-1} \Delta I_n + \bar{N} \Delta \delta \quad (7)$$

where $\Delta I_n = \begin{bmatrix} \Delta i_{d1} \\ \Delta i_{q1} \\ \Delta i_{d2} \\ \Delta i_{q2} \\ \vdots \end{bmatrix}$, $\Delta I_m = \begin{bmatrix} \Delta i_{d1} \\ \Delta i_{q1} \\ \Delta i_{d2} \\ \Delta i_{q2} \\ \vdots \end{bmatrix}$, $\bar{N} = \begin{bmatrix} -i_{q1} \\ i_{d1} \\ & -i_{q2} \\ & i_{d2} \\ & & \ddots \end{bmatrix}$, $\bar{N} = \begin{bmatrix} i_{q1} \\ -i_{d1} \\ & i_{q2} \\ & -i_{d2} \\ & & \ddots \end{bmatrix}$

Assuming that the network has been reduced retaining only the nodes at which machines are connected, the relationship between voltages and currents in network reference frame is given by

$$I_n = Y_n E_n \quad (8)$$

Where Y_n is the $2n \times 2n$ network admittance matrix written in real form after separating the real and imaginary parts given by

$$Y_n = \begin{bmatrix} g_{11} & -b_{12} & g_{12} & -b_{13} & \dots \\ b_{12} & g_{11} & b_{12} & g_{13} & \dots \\ g_{21} & -b_{21} & g_{22} & -b_{23} & \dots \\ b_{21} & g_{21} & b_{22} & g_{23} & \dots \\ \vdots & \vdots & \vdots & \vdots & \ddots \end{bmatrix}$$

Equation 8 can be written as

$E_n = Z_n I_n$, where Z_n is the inverse of Y_n . After linearization this gives

$$\Delta E_n = Z_n \Delta I_n \quad (9)$$

The differential and algebraic equations of synchronous machine model 3 are given in equations 25 through 29 of the previous appendix. For n machines, the voltage equations can be written in a matrix form after linearization as:

$$\Delta E_m + X \Delta I_m = \Delta E \quad (11)$$

where

$$\Delta E = \begin{bmatrix} \Delta e_{d1} \\ \Delta e_{q1} \\ \Delta e_{d2} \\ \Delta e_{q2} \\ \vdots \end{bmatrix} \quad \text{and} \quad X = \begin{bmatrix} r_{d1} & -x'_{q1} & & & \\ x'_{d1} & r_{d1} & & & \\ & & r_{d2} & -x'_{q2} & \\ & & x'_{d2} & r_{d2} & \\ & & & & \ddots \end{bmatrix}$$

Using equations 5, 9 and 6, equation 10 can be reduced to

$$\Delta I_m = A \Delta \delta + B \Delta E \quad (12)$$

where $B = T^{-1} [Z_n + T X T^{-1}]^{-1} T$

and $A = \bar{N} - B [N + X \bar{N}]$

The linearized differential equations for the machine internal voltages can be written in a matrix form as

$$p \Delta E = P \Delta E + Q \Delta I_m + \Delta E_f \quad (13)$$

where $P = \text{diag} \left(\frac{-1}{T_{d01}}, \frac{-1}{T_{d01}}, \frac{-1}{T_{d02}}, \frac{-1}{T_{d02}}, \dots \right)$

$$Q = \begin{bmatrix} Q_1 & & \\ & Q_2 & \\ & & \ddots \end{bmatrix}, \quad Q_i = \begin{bmatrix} 0 & (x_{qi} - x'_{qi})/T_{qi} \\ -(x_{di} - x'_{di})/T_{di} & 0 \end{bmatrix}$$

$$\text{and } \Delta E_f = \begin{bmatrix} 0 & \frac{\Delta e_{f1}}{T_{d01}} & 0 & \frac{\Delta e_{f2}}{T_{d02}} & \dots \end{bmatrix}^T$$

Substituting the expression for ΔI_m from equation 11 and rearranging, equation 12 reduces to

$$p \Delta E = C \Delta \delta + D \Delta E + \Delta E_f \quad (14)$$

where $C = Q A$ and $D = P + Q B$

The equation of motion in linearized form can be arranged in matrix form, for n machines, as

$$p \Delta \delta = \Delta \omega \quad (15)$$

$$\text{and } p \Delta \omega = \Delta t_m + S \Delta E + V \Delta I_m + K \Delta \omega \quad (16)$$

where $\Delta t_m = \pi f_0 \begin{bmatrix} \frac{\Delta T_{i1}}{H_1} \\ \frac{\Delta T_{i2}}{H_2} \\ \vdots \end{bmatrix}$, $S = \begin{bmatrix} S_1 & & \\ & S_2 & \\ & & \ddots \end{bmatrix}$, $S_i = \pi f_0 \begin{bmatrix} -\frac{x'_{di}}{H_i} & -\frac{x'_{qi}}{H_i} \\ \frac{x_{di}}{H_i} & \frac{x_{qi}}{H_i} \end{bmatrix}$

$$V = \begin{bmatrix} V_1 & & \\ & V_2 & \\ & & \ddots \end{bmatrix}, \quad V_i = -\frac{(e_{d1} + r_{a1} i_{d1} - x'_{d1} i_{q1}) \pi f_0}{H_i} - \frac{(e_{q1} + r_{a1} i_{q1} + x'_{q1} i_{d1}) \pi f_0}{H_i}$$

and $K = \text{diag} \left(\frac{-K_{d1}}{2 H_1}, \frac{-K_{d2}}{2 H_2}, \dots \right)$

Substituting the expression for ΔI_m from equation 11, equation 15 reduces to

$$p \Delta \omega = \Delta t_m + J \Delta \delta + F \Delta E + K \Delta \omega \quad (17)$$

where $J = V A$ and $F = S + V B$

For constant input torque $\Delta t_m = 0$

The linearized excitation control equations can be arranged in a matrix form, for n machines, as

$$p x_{ex} = K_{ex} x_{ex} + L \Delta E_t \quad (18)$$

where

$$x_{ex} = [\Delta e_{f1}, \Delta e_{f2}, \Delta e_{f3}, \dots]^T$$

$$K_{ex} = \begin{bmatrix} K_{ex1} & & \\ & K_{ex2} & \\ & & \ddots \end{bmatrix}$$

$$K_{ex1} = \begin{bmatrix} -\frac{1}{T_{AC}} & -\frac{K_{AC}}{T_{AC}} \\ -\frac{K_{FC}}{T_{AC} T_{FC}} & -\left(\frac{K_{AC} K_{FC}}{T_{AC} T_{FC}} + \frac{1}{T_{FC}} \right) \end{bmatrix}$$

$$L = \begin{bmatrix} L_1 & & \\ & L_2 & \\ & & \ddots \end{bmatrix}, \quad L_1 = \begin{bmatrix} -\frac{K_{AC}}{T_{AC}} \\ -\frac{K_{AC} K_{FC}}{T_{AC} T_{FC}} \end{bmatrix}$$

$$\Delta E_t = [\Delta E_{t1}, \Delta E_{t2}, \dots]^T$$

The terminal voltage vector ΔE_t is related to the axis voltage vector ΔE_m by the equation

$$\Delta E_t = E_t \Delta E_m \quad (19)$$

where

$$E_t = \begin{bmatrix} \frac{e_{d1}}{E_{d1}} & \frac{e_{q1}}{E_{d1}} & & \\ & \frac{e_{d2}}{E_{d2}} & \frac{e_{q2}}{E_{d2}} & \\ & & \ddots & \end{bmatrix}$$

Using equations 18, 10 and 11, equation 17 reduces to

$$p x_{ex} = K_{ex} x_{ex} + G \Delta E + H \Delta \delta \quad (20)$$

where $G = L E_t [I - X B]$ and $H = -L E_t X A$

So far all the synchronous machines have been considered to be represented by model 3. Some of the steps described above need to be modified when some of the machines are represented by the classical model (Model 1).

The equations for this model in 2-axis form are

$$0 = e_d + r_a i_d - x'_d i_q \quad (21)$$

$$\text{and } e'_q = e_q + r_a i_q + x'_d i_d \quad (22)$$

when e'_q is the constant voltage behind transient reactance x'_d . This voltage being constant there will be no differential equation to represent flux changes.

Written in matrix form, the voltage equation, after linearization, becomes, for a number of machines

$$\Delta E_m + X \Delta I_m = \Delta E \quad (23)$$

where the matrix X is the same as in equation 10 with x'_q changed to x'_d . However, ΔE in this case will be a null vector.

For the complete system, equations 10 and 22 are written as one matrix equation before forming equation 11.

The expression for torque output for the classical model is given by

$$T_e = e'_q i_q \quad (24)$$

After linearization this becomes

$$\Delta T_e = e'_q \Delta i_q \quad (25)$$

Therefore the equation of motion for the machines employing simplified model in matrix form, after linearization, becomes

$$p \Delta \delta = \Delta \omega \quad (25)$$

$$p \Delta \omega = V \Delta I_m + K \Delta \omega \quad (26)$$

where the matrix V is given by

$$V = \begin{bmatrix} 0 & -\frac{\pi h_1 e_1'}{H_1} & & \\ & 0 & -\frac{\pi h_2 e_2'}{H_2} & \\ & & \ddots & \\ & & & 0 \end{bmatrix}$$

For the complete system, equations 15 and 26 are written as one matrix equation of the form of equation 15, the matrix S being modified by introducing the appropriate number of zeros, while the new V matrix is given by

$$V = \left[\begin{array}{c|c} \text{V for model 3} & \\ \hline & \text{V for model 1} \end{array} \right]$$

By eliminating ΔI_m the equation reduces to that given by equation 16.

Equations 13, 14, 16, and 19 contain only the state variables and from these the state space equation can be formed as shown in equation 27.

$$\begin{bmatrix} \Delta \delta \\ \Delta \omega \\ \Delta E \\ \Delta x_{ik} \end{bmatrix} = \begin{bmatrix} & I & & \\ A & K & F & \\ C & & D & T \\ H & & G & K \end{bmatrix} \begin{bmatrix} \Delta \delta \\ \Delta \omega \\ \Delta E \\ x_{ik} \end{bmatrix} \quad (27)$$

In this equation, the matrix T is given by

$$T = \begin{bmatrix} 0 & 0 & 0 & 0 & \dots \\ \frac{1}{T_{d01}} & 0 & 0 & 0 & \dots \\ 0 & 0 & 0 & 0 & \dots \\ 0 & 0 & \frac{1}{T_{d02}} & 0 & \dots \\ \vdots & \vdots & \vdots & \vdots & \ddots \end{bmatrix}$$

It may be noted that most of the matrices involved in the operation are either diagonal or block diagonal matrices and this can be utilized to advantage during matrix operations.

Singularity of the Coefficient Matrix

Because of the representations adopted here, the coefficient matrix of a multi-machine system is singular in the absence of an infinite bus and when absolute values of the machine angles are considered - the columns corresponding to the $\Delta \delta$'s will add up to zero - resulting in a zero eigenvalue. This is because the system is actually of order $(m \times n - 1)$ and not $m \times n$, where m is the number of state variables per machine, assuming all the machines represented similarly. The singularity can be avoided, if desired, by expressing the angles of the machines with reference to a particular machine taken as a reference, thus reducing the number of variables by one. This calls for a few minor changes in the coefficient matrix. For example, taking the n th machine as a reference, the required changes can be achieved by deleting the row and column corresponding to $\Delta \delta_n$ and placing -1 in the intersection of the rows corresponding to $\Delta \delta_i$'s ($i=1, 2, \dots, n-1$) and the column corresponding to $\Delta \omega_n$. Apart from eliminating the zero eigenvalue the non-zero eigenvalues will remain unchanged regardless of which machine is taken as reference. This can be demonstrated by applying the fundamental properties of determinants.

When an infinite busbar is present and the machine angles are measured with reference to that busbar the system will be of $m \times n$ th order and the original coefficient matrix will be non-singular.

Derivative of the Coefficient Matrix

An important advantage in using the present technique is that in the final coefficient matrix, the elements involving any particular parameter of the system can be easily located. This enables the partial derivative of the coefficient matrix with respect to that parameter to be formed without undue difficulty. The partial derivative of the coefficient matrix is required in calculating the sensitivities of eigenvalues and eigenvectors with respect to a system parameter. The sensitivities of the eigenvalues λ_i and eigenvectors Y_i of the coefficient matrix A with respect to a system parameter can be shown to be given by

$$\frac{\partial \lambda_i}{\partial \alpha} = \frac{Y_i^t \frac{\partial A}{\partial \alpha} X_i}{Y_i^t X_i} \quad \text{and} \quad \frac{\partial X_i}{\partial \alpha} = \sum_{j=1}^n \mu_{ij} X_j \quad \text{respectively}$$

where μ_{ij} are given by

$$\mu_{ij} = \frac{Y_j^t \frac{\partial A}{\partial \alpha} X_i}{(\lambda_i - \lambda_j) Y_j^t X_j}$$

and the Y_i are the eigenvectors of the transpose of A.

For example, if the sensitivity of the eigenvalue λ_i with respect to a parameter of the excitation control system, say K_A , is desired, it is easily seen that only the matrices G, H and K_{ex} contain this parameter. The derivatives with respect to K_A of all the other submatrices forming the final A matrix are zero. The derivative of K_{ex} can be easily formed by inspection. The derivatives of G and H can be seen to be

$$\frac{\partial G}{\partial K_A} = \frac{\partial L}{\partial K_A} E_t [I - XB] \quad \text{and} \quad \frac{\partial H}{\partial K_A} = -\frac{\partial L}{\partial K_A} E_t X A$$

since of the matrices of which G and H are formed only L contains K_A .

Inclusion of Induction Motor

Only the intermediate steps before forming the final coefficient matrix will be shown. The induction machine equations as given in the previous appendix can be linearized and written in matrix form as

$$p \Delta E = P \Delta \omega + Q \Delta I_m + R \Delta s \quad (28)$$

where

$$P = \begin{bmatrix} P_1 & & \\ & P_2 & \\ & & \ddots \end{bmatrix}, \quad P_i = \begin{bmatrix} -\frac{1}{T_{d0i}} & s_i \omega_o \\ -s_i \omega_o & -\frac{1}{T_{d0i}} \end{bmatrix}$$

$$R = \begin{bmatrix} R_1 & & \\ & R_2 & \\ & & \ddots \end{bmatrix}, \quad R_i = \begin{bmatrix} e_{q'i} \omega_o \\ -e_{d'i} \omega_o \end{bmatrix}$$

$$\text{and} \quad \Delta s = [\Delta s_1 \Delta s_2 \dots]^t$$

The matrix Q is the same as in (12) with x_d and x_q changed to x and x'_d and x'_q changed to x' .

$$p \Delta s = S \Delta E + V \Delta I_m \quad (29)$$

where

$$S = \begin{bmatrix} S_1 & & \\ & S_2 & \\ & & \ddots \end{bmatrix}, \quad S_i = \begin{bmatrix} \frac{e_{d'i}}{2H_i} & \frac{e_{q'i}}{2H_i} \\ \frac{e_{q'i}}{2H_i} & \frac{e_{d'i}}{2H_i} \end{bmatrix}$$

and

$$V = \begin{bmatrix} V_1 & & \\ & V_2 & \\ & & \ddots \end{bmatrix}, \quad V_i = \begin{bmatrix} \frac{e_{d'i}}{2H_i} & \frac{e_{q'i}}{2H_i} \\ \frac{e_{q'i}}{2H_i} & \frac{e_{d'i}}{2H_i} \end{bmatrix}$$

$$\Delta E_m + X \Delta I_m = \Delta E \quad (30)$$

where the matrix X is the same as in equation 10 with x_d' and x_q' replaced by x .

In the induction machine equations, the axis voltages and currents are referred to a set of synchronously rotating axes which can be assumed to coincide with the network reference axes. Therefore in the equations, similar to equations 4 and 6, for the induction machines the matrix T will be a unit matrix and the vector ds will be a null vector.

For the complete system equations 10 and 30 are written as one matrix equation before forming equation 11.

The differential equations to the internal voltages of all the synchronous and induction machines can be collected and written in a matrix form as

$$p \delta E = P \delta E + Q \delta I_m + R \delta s + \delta E_f \quad (31)$$

The new P and Q matrices for the mixed machine representations will be given by

$$P = \begin{bmatrix} P \text{ for syn. machine} & \text{---} \\ \text{---} & P \text{ for induction machine} \end{bmatrix}$$

$$Q = \begin{bmatrix} Q \text{ for syn. machine} & \text{---} \\ \text{---} & Q \text{ for induction machine} \end{bmatrix}$$

and the matrix R and the vector δE_f are augmented by introducing an appropriate number of zero elements.

Substituting the expression for δI_m from equation 11 and rearranging, equation 31 reduces to

$$p \delta E = C \delta s + D \delta E + R \delta s + \delta E_f \quad (32)$$

where $C = QA$ and $D = P + QB$

Similarly the equation of motion for all the synchronous and induction machines can be written as one matrix equation of the form of equation 15 with appropriate modifications of the matrices S , V and K . By eliminating δI_m as before the state space form of equation 16 will be obtained.

Dynamic Stability Studies

In this method of studying dynamic stability the whole multi-machine system is represented by one linear vector matrix equation and hence the eigenvalues contain information on the dynamic response of the whole set of system variables rather than a few in which we are usually interested. Any change in the system dynamic performance due to a change in the system parameter can only be assessed by a proper interpretation of the eigenvalues. A change in the control parameter of a particular machine may have effects on other machines which may be quite remote and this will be reflected in the eigenvalues.

The solution of the vector differential equation, $\dot{x} = Ax$, may be written as $x = \sum_{i=1}^n k_i \lambda_i^t x^i$, where the λ_i are the

eigenvalues and x^i are the associated eigenvectors and k_i are arbitrary constants. It is assumed for simplicity that all the λ_i are distinct. The vector of the arbitrary constants can

be found from $k = X^{-1}x_0$ where x_0 is the vector of initial perturbations and X is a matrix whose columns are the vectors x^i . From the solution, it is clear that for a stable system a real eigenvalue will give rise to an exponentially decaying nonoscillatory term, the decay time constant being the reciprocal of the eigenvalue, whereas a conjugate pair of complex eigenvalues will give rise to an oscillatory term having an angular frequency equal to the imaginary part, the oscillations decaying exponentially with a time constant which is the reciprocal of the real part. Thus in a linear dynamic system the eigenvalues correspond to the natural modes of response. An eigenvalue with a small negative real part will indicate the presence of a transient term which is slow to die out. However, the relative magnitude of that term in a particular variable will depend on the particular element of the associated eigenvector.

The advantage of using a state space method in dynamic stability studies is that it is independent of the type of the disturbance so long as the latter is small enough to render the linearization of the system equations valid. Selection of a particular set of state variables is immaterial since the eigenvalues of the system will remain unaltered by a different choice of the state variables although the coefficient matrix will be different.

APPENDIX C-2

LONG TERM TIME DOMAIN

DYNAMIC STABILITY ANALYSIS

The long-term dynamic response refers to the composite performance of the generation, transmission, control and load elements of a power system over periods of time measured in minutes, rather than in cycles or seconds as is usual in short term response, following a major disturbance. A long-term response is characterized by power and voltage transients and frequency excursions resulting from sustained imbalance between generation and load. This phenomenon, on several occasions, has led to cascading outages resulting in widespread blackouts. A project funded by EPRI was undertaken by G E in an effort to better understand the significant factors which contribute to cascading outages and to identify corrective measures to reduce the severity of disturbances.

Phase I and II of the project have been completed and reported in RP 907-1 and RP 764-1, respectively. RP 907-1 described the development of a prototype computer program LOTDYS, which is capable of simulating power system performance for periods up to 20 minutes following major disturbances. The simulations include generation, transmission, protection and load transients. The synchronizing power and rotor angle swings with period less than approximately 10 secs are not included. The program can also simulate an island created by a power system split-up through its ability to be restarted from a midpoint or the end of a previous run.

The basic working LOTDYS is similar to that of a conventional dynamic simulation program. However, the mathematical formulation is such that a large time step of the order of a second is permissible which will result in reasonable computer running times for studies simulating dynamics over a long period of real time. Several considerations make this possible. Firstly, the transients due to the excitation control systems have been neglected. Since the time constants associated with the excitation control systems are negligibly small in relation to the total study time, it would be reasonable to assume that, for a properly stabilized control system, the transients will be over before the power system oscillations, due to the sustained imbalance of generation and load, get started. For the same reason the effects of machine electrical transients involving small time constants can be neglected and the need for a small time step is thus eliminated. Also, the inter-machine oscillations have been neglected. Thus all the synchronous machines simulated in the program are assumed to be running at the same speed. The speed is determined by the net difference between ac-

celerating and decelerating torques on the machine shafts. This assumption of machine coherency allows a much larger time step.

LOTDYS has the ability to perform a complete load flow at each time step, if necessary, to determine conditions on the network and to compute the mismatch between aggregate system load and prime mover output. However, the program will normally utilize extrapolation factor to compute the system acceleration at each time step when conditions do not change very much between steps, thus reserving the longer task of computing a complete load flow only at intervals much greater than one second.

In conventional dynamic simulation programs, a simplified prime mover model is generally employed due to the large time constants of most part of the system. The slow boiler transients are not considered at all. In LOTDYS, the prime mover models employ a detailed representation of the fossil fired, GE BWR and hydro systems. Particular attention has been given to the representation of auxiliary system at off-nominal voltage and frequency.

LOTDYS has been designed to complement the conventional transient stability program, and therefore, would be run in conjunction with one. A transient stability program would be run to analyze the effects during the first few seconds following a major initial disturbance to ascertain transient and short-term dynamic stability. LOTDYS would then take over and simulate the long term dynamics, lasting over a period of several minutes, following a chosen scenario to determine the ultimate response of the system. If at some time perhaps several minutes, following the initial disturbance another major event occurs, for example tripping of a line, loss of a unit etc., the short time transient stability program would be run for a short period following the event and LOTDYS would supply the initial condition. After the transient stability is established, the responses would be simulated by LOTDYS for the remaining period until a steady-state is reached.

The above procedure is certainly attractive in determining whether the system eventually stays together or falls apart during the prolonged period of imbalance between generation and load when corrective measures, such as load shedding, line tripping, etc., are being taken after the system has survived the initial shock following a major disturbance. However, this assumes that the long-term system break-up is purely the result of sustained imbalance between generation and load. The real cause may be the existence of an unstable mode originating in the fast acting control system which is not somehow excited during the first few seconds of the simulation by short-term transient stability program. During the subsequent period of the simulation by LOTDYS the instability, if any, due to an unstable mode will not show up since the short time constants are neglected in the program. Neglect of the short time constants in the long term dynamic simulation program is imperative since unless the integration time step is much smaller than the smallest time constant, computational instability may result. This difficulty can, however, be eliminated to a great extent by first analyzing the eigenvalues of the system represented in full detail. Thus along with a conventional short-term transient stability pro-

gram, an eigenvalue program should also complement the long-term dynamic simulation program.

The mathematical formulation and technical details are given in report RP-907-1. The report, RP 764-1, describes the improvements and extensions of the work described in RP 907-1. The prototype long-term dynamic simulation program LOTDYS has been extended in terms of efficiency and applicability. It is now capable of handling moderately large systems. Sparsity programming techniques along with extrapolative load flow process have reduced the computational cost of the simulation. It also includes models of nuclear stations with boiling water reactor, combustion turbine units, volts/Hertz regulator options in generator and load area voltage regulators. These are discussed in some details in separate chapters. Illustrations are given to show how the program can be used to enable the evaluation of specific measures which might be taken to reduce the severity of disturbances.

Phase III of this project is now in progress in applying the LOTDYS method to simulate several actual utility system disturbances in order to validate the method and provide further improvements of the models.

It has been stated in the reports that the long term simulation program would be used in conjunction with a conventional short-term transient stability program. The conventional stability program will simulate the system response during the first few seconds following a major disturbance. The long term program will take over once the short-term stability has been established. If during the long-term simulation there is further major disturbance, the short-term program would be called upon and the long term program would provide the starting conditions. It is recommended that this process is carried one step further. During the computation in the long term program so long as the changes in the voltages and frequencies are small the fast acting elements in the control systems can be assumed to be inoperative, since they are in most cases activated by voltage and speed variations. Therefore any unstable mode associated with these elements that might be present will not excite unstable oscillations. It is suggested that the long-term simulation program be made capable of transferring control to the short-term program as soon as it detects significant changes in voltages and/or frequency even though there is no major disturbance.

APPENDIX C-3 SUBSYNCHRONOUS OSCILLATIONS

The insertion of series capacitors into transmission systems creates oscillatory electric circuits that have natural frequencies in the subsynchronous range. At this frequency range, a synchronously rotating machine behaves like an induction generator. The amount of energy generated by the induction generator action is a function of the magnitude of the rotor resistance at the subsynchronous or slip frequency. If the system is poorly damped, the machine could feed more energy than is absorbed by the resistance loss in the transmission lines resulting in sustained subharmonic oscillations. The self excited currents may be initiated and grow quite independently of any applied armature voltage or field excitation. In the presence of field excitation, this will interact with the transient subharmonic currents to produce pulsating air-gap torques at slip frequency, which will in turn produce rotor oscillations and corresponding shaft torques. This pulsating torque may excite significant torsional movement of the rotor if the slip frequency is close to any of the mechanical torsional natural frequencies of the unit. Furthermore, the rotor oscillations will produce voltages in the armature circuits which will reinforce the self excited currents. Eventually, these coupled mechanical and electrical system oscillations may reinforce each other to the point where they become unstable. The shaft torques will build up spontaneously to damaging levels without any large initiating system disturbance.

The three principal aspects of the problem of subsynchronous resonance are:

- 1) generator self-excitation due to induction generator effects
- 2) interaction between the self excited oscillations and the mechanical torsional movements of the shaft.
- 3) combined generator and turbine rotor hunting.

The third mode can exist without series capacitor compensation and is not a subsynchronous resonance problem although it can be enhanced by it.

The method of analysis presented here is principally concerned with the instability of the first two types, particularly the second, although this will include the third mode as well. Analysis concerning the third form of instability only need not be carried out in such details.

A state space approach of analyzing the subsynchronous resonance problem is illustrated. This method offers more insight into the phenomenon than other methods of analysis. The eigenvalues of the coefficient matrix of the state space equation represent the character of the normal modes of the small-signal time response whereas the eigenvectors represent the mode shapes. The analysis of the subsynchronous resonance problem is more complicated than those of the conventional transient and dynamic stability problems due to the necessity of including the generator stator and network transient effects (p and q terms).

A single machine connected to an infinite bus as shown in Figure 1A is considered. The torsional system is shown in Figure 1B. A simplified excitation system model as considered in the previous appendix in connection with the dynamic stability calculation is used in this illustration. However, any other model along with power system stabilizers can be easily incorporated. The turbine control system is not considered since its inclusion does not present any difficulty.

Fig. 1A

Fig. 1B

The synchronous machine equations in d-q axis reference frame are given by equations 1 through 13 of the appendix on transient stability.

The flux linkage equations (equs. 1-6) after linearization can be written in matrix form as

$$\begin{bmatrix} d\psi_r \\ d\psi_s \end{bmatrix} = X \begin{bmatrix} di_r \\ di_s \end{bmatrix} \quad (1)$$

$$\text{where } d\psi_r = \begin{bmatrix} d\psi_{rd} \\ d\psi_{rq} \\ d\psi_{rd} \\ d\psi_{rq} \end{bmatrix}, \quad d\psi_s = \begin{bmatrix} d\psi_{sd} \\ d\psi_{sq} \end{bmatrix}$$

$$di_r = \begin{bmatrix} di_{rd} \\ di_{rq} \\ di_{rd} \\ di_{rq} \end{bmatrix}, \quad di_s = \begin{bmatrix} di_{sd} \\ di_{sq} \end{bmatrix}$$

$$\text{and } X = \begin{bmatrix} x_{Hd} & x_{fid} & & & -x_{ad} \\ & x_{fid} & & & -x_{ad} \\ & & x_{Hq} & x_{fq} & -x_{aq} \\ & & x_{fq} & x_{Hq} & -x_{aq} \\ x_{ad} & x_{ad} & & & -x_d \\ & & x_{aq} & x_{aq} & -x_q \end{bmatrix}$$

From equation 1

$$\begin{bmatrix} di_r \\ di_s \end{bmatrix} = Y \begin{bmatrix} d\psi_r \\ d\psi_s \end{bmatrix} \quad (2)$$

where Y is the inverse of X

Equation 2 can be broken down into two equations as

$$di_r = P d\psi \quad (3)$$

$$di_s = Q d\psi \quad (4)$$

$$\text{where } d\psi = \begin{bmatrix} d\psi_r \\ d\psi_s \end{bmatrix}$$

and P and Q matrices are obtained from Y.

The transmission line equations in d-q frame are given by

$$e_d = E_b \sin \delta_3 + R_L i_d - \frac{\omega_s}{\omega_0} X_L i_q + \frac{1}{\omega_0} X_L p i_d + E_{cd} \quad (5)$$

$$e_q = E_b \cos \delta_3 + R_L i_q - \frac{\omega_s}{\omega_0} X_L i_d + \frac{1}{\omega_0} X_L p i_q + E_{cq} \quad (6)$$

$$i_d = - \frac{\omega_s}{\omega_0 X_C} E_{cq} + \frac{1}{\omega_0 X_C} p E_{cd} \quad (7)$$

$$i_q = \frac{\omega_s}{\omega_0 X_C} E_{cd} + \frac{1}{\omega_0 X_C} p E_{cq} \quad (8)$$

where E_b = infinite bus voltage

E_{cd} , E_{cq} = d and q axis voltages across the series capacitor

ω_0 = synchronous speed

APPENDIX D SHORT CIRCUIT CALCULATION

The performance equation for a three-phase network in the bus frame of reference is

$$E_{bus}^{a,b,c} = Z_{bus}^{a,b,c} I_{bus}^{a,b,c} \quad (1)$$

Where $E_{bus}^{a,b,c}$ = Vector of three-phase bus voltages measured with respect to the reference bus.

$I_{bus}^{a,b,c}$ = Vector of impressed three phase bus currents

$Z_{bus}^{a,b,c}$ = Three phase bus impedance matrix.

In short circuit studies, the following simplifications can be made without sacrificing accuracy appreciably:

1. Represent each machine by a constant voltage behind reactance, transient or subtransient
2. Neglect shunt connections, e.g. loads, line charging, etc.
3. Set all transformers at nominal taps. Also, it is usually sufficient to represent transmission line and transformer impedances by their reactances.

Fig. 1

The performance equation of a system during a fault, from Thevenin's theorem, is

$$E_{bus(f)}^{a,b,c} = E_{bus(0)}^{a,b,c} + Z_{bus}^{a,b,c} I_{bus(f)}^{a,b,c} \quad (2)$$

The bus current vector during a fault at bus p is

$$I_{bus(f)}^{a,b,c} = \begin{bmatrix} 0 \\ \vdots \\ -I_p^{a,b,c} \\ \vdots \\ 0 \end{bmatrix} \quad (3)$$

$$\begin{aligned} E_1(f)^{a,b,c} &= E_1(0)^{a,b,c} - Z_{1p}^{a,b,c} I_p(f)^{a,b,c} \\ E_2(f)^{a,b,c} &= E_2(0)^{a,b,c} - Z_{2p}^{a,b,c} I_p(f)^{a,b,c} \\ E_p(f)^{a,b,c} &= E_p(0)^{a,b,c} - Z_{pp}^{a,b,c} I_p(f)^{a,b,c} \end{aligned} \quad (4)$$

$E_1^{a,b,c}, I_p^{a,b,c}$ etc. are 3×1 vector and $Z_{1p}^{a,b,c}$ etc. are 3×3 matrices.

$$E_p(f)^{a,b,c} = Z_f^{a,b,c} I_p(f)^{a,b,c} \quad (5)$$

where $Z_f^{a,b,c}$ is the three-phase impedance matrix for the fault

The above equations can be simplified considerably by the method of symmetrical components.

Using the transformation $E_{1,2,0}^{a,b,c} = T E_{1,2,0}^{1,2,0}$,

$I_{1,2,0}^{a,b,c} = T I_{1,2,0}^{1,2,0}$ where

$$T = \begin{bmatrix} 1 & 1 & 1 \\ a^2 & a & 1 \\ a & a^2 & 1 \end{bmatrix}$$

and 1,2,0 refer to the positive, negative and zero sequence quantities respectively.

Equation 2 reduces to

$$E_{bus(f)}^{1,2,0} = E_{bus(0)}^{1,2,0} - Z_{bus}^{1,2,0} I_{bus(f)}^{1,2,0} \quad (6)$$

where each element of the transformed Z_{bus} is a 3×3 diagonal

matrix diagonal matrix made up of elements Z_{ij}^1, Z_{ij}^2 and Z_{ij}^0 of the positive, negative and zero sequence bus impedance matrices $Z_{bus}^1, Z_{bus}^2, Z_{bus}^0$ respectively.

The fault impedance matrix $Z_f^{a,b,c}$ and the fault admittance matrix $Y_f^{a,b,c}$ can be transformed into the matrices $Z_f^{1,2,0}$ and $Y_f^{1,2,0}$ respectively. The resulting matrix is diagonal if the fault is balanced.

The equations for calculating fault currents and voltages (equations 4 and 5) can be written in terms of symmetrical components.

The current at the faulted bus p is

$$I_p(f)^{1,2,0} = (Z_f^{1,2,0} + Z_{pp}^{1,2,0})^{-1} E_p(0)^{1,2,0} \quad (7)$$

or

$$I_p(f)^{1,2,0} = Y_f^{1,2,0} (I + Z_{pp}^{1,2,0} Y_f^{1,2,0})^{-1} E_p(0)^{1,2,0} \quad (8)$$

The voltage at the faulted bus p is

$$E_p(f)^{1,2,0} = Z_f^{1,2,0} (Z_f^{1,2,0} + Z_{pp}^{1,2,0})^{-1} E_p(0)^{1,2,0} \quad (9)$$

or

$$E_p(f)^{1,2,0} = (I + Z_{pp}^{1,2,0} Y_f^{1,2,0})^{-1} E_p(0)^{1,2,0} \quad (10)$$

The voltages at buses other than p are

$$E_i(f)^{1,2,0} = E_i(0)^{1,2,0} - Z_{ip}^{1,2,0} (Z_f^{1,2,0} + Z_{pp}^{1,2,0})^{-1} E_p(0)^{1,2,0} \quad (11)$$

or

$$E_i(f)^{1,2,0} = E_i(0)^{1,2,0} - Z_{ip}^{1,2,0} Y_f^{1,2,0} (I + Z_{pp}^{1,2,0} Y_f^{1,2,0})^{-1} E_p(0)^{1,2,0} \quad (12)$$

The fault current in the three-phase element i-j is

$$I_{ij(f)}^{1,2,0} = Y_{ij}^{1,2,0} (E_i(f)^{1,2,0} - E_j(f)^{1,2,0}) \quad (13)$$

The index ff includes all elements mutually coupled to the element i,j as well as i,j. Each $Y_{ij}^{1,2,0}$ is a 3×3 diagonal matrix and is an element of the transformed primitive admittance matrix.

Three-Phase to Ground and Single-Phase to Ground Fault

The balanced three-phase to ground fault and the single phase to ground fault cases and the corresponding fault impedance and admittance matrices in terms of symmetrical components are shown below.

Fig. 2a

Figure 2b

Three phase fault current and the bus voltages are obtained by substituting the appropriate $Z_{1,2,0}$ in equations 7, 9 and 11. Since the pre-fault voltages are balanced

$$\begin{bmatrix} 1,2,0 \\ E_p(0) \end{bmatrix} = \begin{bmatrix} E_p(0) \\ 0 \\ 0 \end{bmatrix}$$

and the fault current is obtained from equation 7 as

$$\begin{bmatrix} I_p(1) \\ I_p(2) \\ I_p(0) \end{bmatrix} = \begin{bmatrix} \frac{E_p(0)}{s_f + Z_{pp}^1} \\ 0 \\ 0 \end{bmatrix} \quad (14)$$

The phase components of the fault current are obtained by premultiplying both sides of equation 14 by T

$$\begin{bmatrix} a,b,c \\ I_p(f) \end{bmatrix} = \frac{E_p(0)}{s_f + Z_{pp}^1} \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} \quad (15)$$

The voltage at the faulted bus p is, from equation 9.

$$\begin{bmatrix} 1,2,0 \\ E_p(f) \end{bmatrix} = \frac{s_f E_p(0)}{s_f + Z_{pp}^1} \begin{bmatrix} 1 \\ 0 \\ 0 \end{bmatrix} \quad (16)$$

The phase components are

$$\begin{bmatrix} a,b,c \\ E_p(f) \end{bmatrix} = \frac{s_f E_p(0)}{s_f + Z_{pp}^1} \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} \quad (17)$$

The voltage at the faulted bus p is

$$\begin{bmatrix} 1,2,0 \\ E_p(f) \end{bmatrix} = \frac{E_p(0)}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \begin{bmatrix} Z_{pp}^1 + Z_{pp}^0 + 3 s_f \\ -Z_{pp}^0 \\ -Z_{pp}^0 \end{bmatrix} \quad (22)$$

The phase components are

$$\begin{bmatrix} a,b,c \\ E_p(f) \end{bmatrix} = E_p(0) \begin{bmatrix} \frac{3 s_f}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \\ \frac{Z_{pp}^1 - Z_{pp}^0}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \\ \frac{Z_{pp}^1 - Z_{pp}^0}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \end{bmatrix} \quad (23)$$

The voltages at buses other than p are

$$\begin{bmatrix} 1,2,0 \\ E_i(f) \end{bmatrix} = \begin{bmatrix} E_i(0) \\ 0 \\ 0 \end{bmatrix} - \frac{E_p(0)}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \begin{bmatrix} Z_{ip}^1 \\ Z_{ip}^0 \\ Z_{ip}^0 \end{bmatrix} \quad (24)$$

$i \neq p$

In phase components

$$\begin{bmatrix} a,b,c \\ E_i(f) \end{bmatrix} = E_i(0) \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} - \frac{E_p(0)}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \begin{bmatrix} Z_{ip}^1 \\ Z_{ip}^0 \\ Z_{ip}^0 \end{bmatrix} \quad (25)$$

Once the voltages have been calculated, the fault current in any branch can be obtained from equation 13.

The voltages at buses other than p are

$$\begin{bmatrix} 1,2,0 \\ E_i(f) \end{bmatrix} = \begin{bmatrix} E_i(0) \\ 0 \\ 0 \end{bmatrix} - \frac{Z_{ip}^1 E_p(0)}{s_f + Z_{pp}^1} \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} \quad (18)$$

$i \neq p$

In phase components

$$\begin{bmatrix} a,b,c \\ E_i(f) \end{bmatrix} = \begin{bmatrix} E_i(0) \\ 0 \\ 0 \end{bmatrix} - \frac{Z_{ip}^1 E_p(0)}{s_f + Z_{pp}^1} \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} \quad (19)$$

It may be seen that in the calculation of balanced three-phase to ground short circuit only the positive sequence quantities need be considered.

In the case of line to ground fault, fault current and the bus voltages are obtained by substituting the appropriate $Z_{1,2,0}$ in equations 8, 10 and 12.

The fault current is obtained as

$$\begin{bmatrix} 1,2,0 \\ I_p(f) \end{bmatrix} = \frac{E_p(0)}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \begin{bmatrix} 1 \\ 1 \\ 1 \end{bmatrix} \quad (20)$$

The phase components are

$$\begin{bmatrix} a,b,c \\ I_p(f) \end{bmatrix} = \frac{3 E_p(0)}{2 Z_{pp}^1 + Z_{pp}^0 + 3 s_f} \begin{bmatrix} 1 \\ 0 \\ 0 \end{bmatrix} \quad (21)$$

Algorithms for building Z bus

The algorithms for building the three sequence matrices are similar. The only difference is due to the fact that transmission lines that share the same right-of-way are magnetically coupled in the zero sequence network. No such coupling exists in the positive or negative sequence network. In power system analysis, the negative sequence network is generally considered to be identical to the positive sequence network. Therefore only the positive and zero sequence matrices need to be formed and stored. When fault analysis involve only balanced three-phase to ground faults the zero sequence matrix is not needed.

Assume that the bus impedance matrix Zbus is known for a partial network of n buses (n can have any value from 1 upwards) and a reference node 0. The performance equation of the network is

$$E_{bus} = Z_{bus} I_{bus} \quad (26)$$

Fig. 3

Addition of a branch

The added branch p-q is assumed to be mutually coupled with one or more elements of the partial network. The elements Z_{qi} of the new row and column can be determined by injecting unit current at the ith bus and calculating the voltage at the qth bus with respect to the reference node. Since all other bus currents are zero

$$E_q = Z_{qi}$$

The currents in the element pq and all other elements of the network that are coupled to pq are expressed in terms of the primitive admittances and the voltages across the elements by

$$\begin{bmatrix} i_{pq} \\ i_{pf} \end{bmatrix} = \begin{bmatrix} y_{pq,pq} & y_{pq,pf} \\ y_{pf,pq} & y_{pf,pf} \end{bmatrix} \begin{bmatrix} v_{pq} \\ v_{pf} \end{bmatrix} \quad (27)$$

pf is a variable subscript referring to all elements coupled by pq .

Since $i_{pq} = 0$, from equation 27

$$i_{pq} = y_{pq,pq} v_{pq} + y_{pq,pf} v_{pf} = 0 \quad (28)$$

and since $v_{pq} = E_p - E_q = z_{p1} - z_{q1}$, and $v_{pf} = E_p - E_f = z_{p1} - z_{f1}$

z_{q1} is obtained from (28) as

$$z_{q1} = z_{p1} + \frac{y_{pq,pf} (z_{p1} - z_{f1})}{y_{pq,pq}} \quad (29)$$

The element z_{qq} is calculated by injecting unit current at the q th bus and calculating the voltage at that bus. Since all other bus currents are zero

$$z_k = z_{kq}$$

Since $i_{pq} = -1.0$

$$y_{pq,pq} v_{pq} + y_{pq,pf} v_{pf} = -1 \quad (30)$$

Substituting for v_{pq} and v_{pf} in (30), z_{qq} is obtained as

$$z_{qq} = z_{pq} + \frac{1 + y_{pq,pf} (z_{p1} - z_{f1})}{y_{pq,pq}} \quad (31)$$

If there is no mutual coupling between the added branch and other elements of the partial network, the elements of $y_{pq,pf}$ are zero

$$\text{and } y_{pq,pq} = \frac{1}{z_{pq,pq}}$$

Therefore,

$$z_{q1} = z_{p1}, i_{fq}$$

$$\text{and } z_{qq} = z_{pq} + z_{pq,pq} = z_{pp} + z_{pq,pq}$$

Furthermore, if there is no mutual coupling and p is the reference node,

$$z_{q1} = 0$$

$$\text{and } z_{qq} = z_{pq,pq}$$

Addition of a link (closing a loop)

When the new element $p-q$ closes a loop, the elements of the bus impedance matrix is recalculated by connecting in series with the added element a voltage source e_1 as shown in Fig. 4. This creates

Fig. 4

a new node which is later eliminated. Unit current is injected at the l th bus and e_1 is adjusted so that $i_{pq} = 0$. Since all other bus currents are zero, $E_k = z_{k1}$ and $i_1 = z_{11}$.

Since $e_1 = E_1 - E_q$ and v_{p1} is the voltage across element $p1$,

$$e_1 = E_p - E_q - v_{p1} \quad (32)$$

From equation 27

$$i_{pq} = i_{p1} = y_{p1,p1} v_{p1} + y_{p1,pf} v_{pf} = 0 \quad (33)$$

Since $y_{p1,p1} = y_{pq,pq}$, and $y_{p1,pf} = y_{pq,pf}$

z_{11} is obtained from (32) and (33) as

$$z_{11} = z_{p1} - z_{q1} + \frac{y_{pq,pf} (z_{p1} - z_{f1})}{y_{pq,pq}} \quad (34)$$

z_{11} is calculated by injecting unit current at 1, so that

$$i_{p1} = -i_1 = -1.0, \text{ and calculating } e_1.$$

Since all other bus currents are zero,

$$E_k = z_{k1}, e_1 = z_{11}$$

Therefore

$$v_{p1} = \frac{-(1 + y_{pq,pf} v_{pf})}{y_{pq,pq}}$$

Substituting for v_{p1} and v_{pf}

$$z_{11} = z_{p1} - z_{q1} + \frac{1 + y_{pq,pf} (z_{p1} - z_{f1})}{y_{pq,pq}} \quad (35)$$

In the absence of mutual coupling, the elements of $y_{pq,pf}$ are zero

$$\text{and } y_{pq,pq} = \frac{1}{z_{pq,pq}}$$

Therefore

$$z_{11} = z_{p1} - z_{q1}$$

$$z_{11} = z_{p1} - z_{q1} + z_{pq,pq}$$

$$= z_{pp} + z_{qq} - 2z_{pq} + z_{pq,pq}$$

Furthermore, if there is no mutual coupling, and p is the reference node,

$$z_{p1} = 0, z_{p1} = 0$$

$$\text{and } z_{11} = -z_{q1}$$

$$z_{11} = z_{qq} + z_{pq,pq}$$

The augmented matrix of the network with the new axis added is

$$\begin{bmatrix} E_1 \\ E_2 \\ \vdots \\ E_m \\ E_1 \end{bmatrix} = \begin{bmatrix} z_{11} & z_{12} & \dots & z_{11} \\ z_{21} & z_{22} & \dots & z_{21} \\ \vdots & \vdots & \ddots & \vdots \\ z_{m1} & z_{m2} & \dots & z_{m1} \\ z_{11} & z_{12} & \dots & z_{11} \end{bmatrix} \begin{bmatrix} i_1 \\ i_2 \\ \vdots \\ i_m \\ i_1 \end{bmatrix} \quad (36)$$

The required bus impedance matrix is obtained by setting $E_1 = 0$

and eliminating the 1 th row and column giving

$$E_{bus} = \left(z_{bus} - \frac{z_{11} z_{11}}{z_{11}} \right) i_{bus} \quad (37)$$

as the performance equation of the partial network including the link $p-q$.

The bus impedance matrix of the network is built by assembling the system one line at a time, and by modifying the matrix to reflect the change in the network equivalent impedances by the addition of the line. Each element of the transmission line is identified by the two buses at the ends of the line. Lines are read at random by their terminal bus numbers and per unit positive and zero sequence impedances. In short circuit studies, the reference bus is selected as the common bus behind all generator reactances and is numbered zero. The line data are reordered by an algorithm such that as each line is selected from the data list for processing, it can be connected to the partially assembled system. The first line must be one from the reference to some bus of the system. After the first line is processed, the matrix is a 1×1 matrix, the element being the impedance of the line. The next line is then selected from the data list and processed using one of the algorithms described depending on whether the new line is a branch or a link (closing a loop). The process is continued until the data list is exhausted.

The line data can be ordered optimally to minimize the time required for the building algorithm but this is not essential.

Modification of Z_{bus} for changes in the network

The changes in the network may be addition of elements, removal of elements, or changes in the impedances of elements. New elements can be added one at a time and the bus impedance matrix modified using the matrix building algorithm. If an element is removed which is not mutually coupled to any other element, the modified bus impedance matrix can be obtained by adding, in parallel with the element, an element whose impedance is equal to the negative of the impedance of the element to be removed. If the impedance of an element is changed, the modified bus impedance matrix is obtained by adding an element in parallel with the element such that the equivalent impedance of the two elements is the desired value. When mutually coupled elements are removed, the modified impedance matrix can be obtained by adding, in parallel with the element, an element with the negative of the impedance but with mutual couplings the same (sign and magnitude) as the original element. The same procedure can be used when there is a change in the impedance of an element which is mutually coupled to other elements.

In the course of a complete fault study usually each line connected to a faulted bus is opened, one at a time, to obtain the new total fault current and the contribution of the remaining lines. A great deal of computation can be saved by working with only the part of the total matrix that is directly involved in the calculations. For example, if the i th bus is the faulted bus and j, k, l are the buses connected to it, a small matrix is extracted from the total matrix as shown

Fig. 5a

Fig. 5b

To open the line $(i-l)$, add a line (loop closing) $(i-l)$ whose impedance is the negative of the original line impedance $Z_{il,il}$

and modify the above small matrix by the matrix building algorithm. In fact, only the i th row needs to be modified since the other elements will not be used in the computation. The magnitude of the fault current that would flow if the fault was removed from bus i and placed on the line side of the open breaker at bus l can be obtained from the driving point impedance of bus m , given by

$$Z_{mm} = Z_{ii} + Z_{il,il}, \text{ where } Z_{ii} \text{ is}$$

the driving point impedance of bus i after the line il is removed.

Short Circuit Studies of Large Systems

In many short circuit studies of very large systems the short circuit information pertaining to a part of the system is needed. In such cases it is unnecessary to build and work with the impedance matrix of the complete system. This not only allows short circuit studies of large systems to be carried out on small computers but the computing times can be greatly reduced. To illustrate the procedure, consider the system divided into two parts - Part A, the study area and Part B outside the study area, with lines connecting the two areas.

Fig. 6

First the data are sorted. Lines described by buses, both of which are in the study area, are placed in one file. All other lines are placed in a file of lines in the outside area. If the area B is composed of several disconnected areas - subareas B_1, B_2, B_3 , etc. data for one subarea is

sorted before going on to the next. When the first subarea has been completed, a new line to the reference is found for the second subarea and the process continued. If it happens that a subarea, isolated from the remainder of area B does not have a reference line, the data of that subarea are combined with the data of the study area A and the line sorting is completed.

The matrix building starts with area B. In the addition of a branch from an existing bus to a new bus the only elements that take an active part in the matrix modification are the elements of the row and column of the existing bus. In the addition of a link (closing a loop) the only rows and columns that take an active part in the matrix modification are the rows and columns of the buses being connected by the new line. Therefore, when all lines have been connected to a bus, the elements of the matrix in the row and column corresponding to the bus will never be required as active participants in the matrix modification. If the bus that has no more lines connected to it is a bus in area B, the row and column corresponding to the bus may be deleted, since the elements of this row and column will not be required in the fault analysis. When all lines have been processed, the matrix that remains will be the impedance matrix of the study area A with the effect of the rest of the system properly taken into account.

The impedance matrix building algorithm as described in this appendix is highly efficient for small and moderately large networks. For very large networks, when the short circuit information pertaining to a small part is required, the impedance matrix building algorithm and short circuit calculations performed. However, in some large scale short circuit studies, it may be necessary to perform a detailed analysis retaining all the nodes in the system. In such cases considerable savings in computing time and storage can be achieved if the solution is obtained through an optimally ordered triangular factorization of the bus admittance matrix, taking full advantage of the sparsity of the matrix.

If, in addition, the study requires only a few elements of the bus impedance matrix, only those elements can be calculated following the triangular factorization, thus further saving computer time and storage.

Although the short circuit calculation using the bus impedance matrix as described throughout this appendix is the most efficient and widely used method of short-circuit analysis of large systems, it is by no means the only method available. Prior to the development of the bus impedance matrix building algorithm, Gauss-Siedel iterative approach as used in load flow calculations has been used to solve the node voltages in short-circuit studies. However, this method is poorly suited to short-circuit studies, since each fault condition requires an iterative solution and therefore, a complete analysis of a large system is prohibitively expensive.

Short circuit calculations may also be performed using the loop impedance matrix. Although this method is more efficient than the nodal iterative approach and comparable to the bus impedance matrix method for small systems, it becomes cumbersome in handling large systems.

APPLICATION TO BREAKER DUTY CALCULATIONS

A system short-circuit study must, as its ultimate objective, determine the interrupting duty of each circuit breaker which may be compared to its interrupting rating. The duty of a breaker is related to the total short-circuit current flowing through it at the instant the breaker starts to part its contacts.

In calculating breaker duties the fault condition should be that which gives maximum current through the breaker under study (normally a solid three-phase or single-line-to-ground fault) and the highest normal operating voltage at the breaker location should be used. All other breakers connected to the faulted point are assumed to have tripped ahead of the breaker under study. The current flowing into the faulted bus under this condition is calculated as previously described. This is the initial asymmetrical component of the fault current. The total current at the instant the breaker parts its contacts must now be determined. Note that the time to be used is the contact parting time, which is the sum of the relay time and the breaker opening time, but does not include the arcing time.

The stator of a generator may be visualized as an R-L circuit with a voltage induced by the rotor field. If a three-phase fault occurs at a voltage zero the initial current will be fully offset and may be resolved into a symmetrical (ac) and an asymmetrical (dc) component. Decay of the dc component may be determined by conventional transient calculation procedures and is a function of the time constant of the stator winding plus all components of the system, i.e. generators, lines, transformers, connected to it. Since there can be no instantaneous change in the flux linkages within the machine and an armature current now exists which produces an mmf opposing the field mmf, dc currents are induced in all rotor windings and in the rotor itself. As these currents decay the net machine excitation is decreased and the symmetrical component of fault current is decreased. Rigorous determination of this decay is extremely complex.

Many methods of including the dc component and the ac and dc decrements have been devised and are explained in the literature. The method currently presented in the industry standard (10) gives, with relatively little effort, results approximately as accurate as the more rigorous approaches. This method involves applying correction factors obtained from curves designed to include the dc offset and the decay in both ac and dc components. These factors depend on the contact parting time, the location of the system which the fault occurs and the X/R ratio as seen from the fault location. In developing these curves, the dc decrement was determined using conventional transient procedures, but the ac decrement is based on an empirical relationship established by a large body of actual data which indicates a relationship between the X/R ratio and the ac decrement as the fault location moves from the generating station bus to a remote location. Previous investigation (11) has shown that for all practical proportions the procedure of reducing the reactance to a single value with complete disregard for the resistance, and reducing the resistance to a single value with complete disregard for the reactance gives more accurate results than any other reasonably simple procedure, including an R+X approach. In addition, the error for practical cases is on the conservative side. This then is the recommended procedure.

APPENDIX E POWER SYSTEMS STATIC OPTIMIZATION

A successful operation of a power system requires considerations of economy, system security and reliability. To ensure satisfactory performance, operating conditions are selected that meet certain specified constraints. Power system static optimization refers to the power flow solution that satisfies these constraints and optimizes certain performance criteria. The several local criteria may be combined into one global criterion by suitably defining an objective function and the optimum (minimum) may be found by a suitable optimization technique. The choice of an objective function is problem dependent. A particular choice of an objective function will lead to the solution of a particular problem.

Before looking into the more general optimization techniques, a review of the classical economic dispatch problem will be in order. Although the classical method does not solve the general power system optimization problem, this is the method most widely used for economic dispatch because of its simplicity and ease of implementation for on-line control.

Classic Economic Dispatch

The classical economic dispatch problem can be stated as:

$$\text{Minimize } C = \sum_{i=1}^n c_i(P_i) \quad (1)$$

where C is the total production cost and c_i 's are the individual production costs of the generator units and are functions of the generator loadings P_i . The minimization is subject to the equality constraint

$$P_D + P_L - \sum_{i=1}^n P_i = 0 \quad (2)$$

where P_D is the total demand and P_L represents the transmission losses, and the inequality constraints

$$P_{i,\min} \leq P_i \leq P_{i,\max} \quad (3)$$

A Lagrangian is defined as

$$L = \sum_{i=1}^n c_i(P_i) + \lambda (P_D + P_L - \sum_{i=1}^n P_i) \quad (4)$$

In the classical economic dispatch problem, the real power generation is optimized.

A necessary condition at the cost minimum is that the partial derivative of L with respect to each P_i must be zero. This results in the following equations

$$\frac{dc_i}{dP_i} - \lambda (1 - \frac{\partial P_L}{\partial P_i}) = 0 \quad (5)$$

for $i = 1, 2, \dots, n$

The $\frac{dc_i}{dP_i}$'s are the incremental costs of generation and are obtained empirically. They can often be represented by straight line segments.

The partial derivative $\frac{\partial P_L}{\partial P_i}$ is the incremental transmission loss

associated with generator unit i . With $\frac{\partial P_L}{\partial P_i}$ known, equation 5 can be

solved for P_i at any given λ . P_i thus obtained should satisfy the equality constraints (2). If not, λ is adjusted until both equations 2 and 5 are satisfied. When solving equations 2 and 5 care is taken to set P_i to a limit if that limit is violated.

A widely used method of evaluating the incremental transmission losses is the use of the B constants. The transmission losses P_L can be expressed as

$$P_L = B_0 + P^t B_1 + P^t B P^t \quad (6)$$

where B_0 is a constant, B_1 is a constant vector, B is a constant matrix and P is a vector composed of the elements P_i . The above loss formula is approximate and based on the following assumptions

- 1) each load current remains a constant complex ratio of the total load current irrespective of the load level
- 2) power factors of all generators and ties remain constant
- 3) the deviations of generator voltages and angles are small.

The incremental losses $\frac{\partial P_L}{\partial P_i}$ follow from equation 6.

Other methods of obtaining incremental losses have been developed. A method used successfully by AEP is as follows:

The total transmission losses of a power system are

$$P_L + j Q_L = I^t Z_{bus} I^t \quad (7)$$

where I is the vector of impressed bus currents.

From (7) the following expression for P_L can be derived:

$$P_L = \begin{bmatrix} P' & A & B \\ Q' & -\beta & \alpha \end{bmatrix} \begin{bmatrix} P' \\ Q' \end{bmatrix} \quad (8)$$

where P' and Q' are the vectors of the real and reactive input powers and A and β are matrices whose elements are

$$A_{ij} = \frac{r_{ij}}{|E_i||E_j|} \cos \theta_{ij}$$

$$\beta_{ij} = -\frac{r_{ij}}{|E_i||E_j|} \sin \theta_{ij}$$

where r_{ij} represents the real part of Z_{bus}

The incremental loss associated with generating unit i is obtained from

$$\frac{\partial P_L}{\partial P_i} = 2 \sum_{j=1}^n (A_{ij} P_j' + \beta_{ij} Q_j') \quad (9)$$

The steps in the procedure for obtaining an optimum real power generation schedule are:

- 1) calculate from load flow data the total demand P_D for the power system.
- 2) estimate the transmission losses P_L in order to obtain the total required generation P_G
- 3) calculate from the current load flow data the A and β coefficients
- 4) estimate λ and calculate P_i from equation 5. If a P_i exceeds a limit, set it at the limit.

- 5) test $\sum_{i=1}^n P_i$ against the required generation P_G and repeat step 4 if the difference is not within a specified tolerance.

- 6) solve the load flow to obtain new system conditions. The difference between the scheduled swing generation, determined in step 4, and the swing generation obtained from the load flow is equal to the difference between the estimated and actual transmission losses.

- 7) return to step 2 to recompute the desired generation with the new estimate of transmission losses.

A solution is obtained when the generation of the swing machine from the economic dispatch and that obtained from the load flow calculation are the same within a specified tolerance.

An extension of the method to reactive power dispatch is as follows. The economic allocation of reactive power can be obtained from

$$Q^{i+1} = Q^i - k^i \nabla P_L^i \quad (10)$$

subject to the constraints

$$Q_{\min} \leq Q \leq Q_{\max} \quad (11)$$

$$|E_{\min}| \leq |E| \leq |E_{\max}| \quad (12)$$

where Q^i , Q^{i+1} are the vectors of the reactive bus powers in iteration i and $i+1$ respectively.

k^i is a positive factor

∇P_L^i is a gradient vector whose elements are the partial derivatives of the real power losses with respect to the reactive power at each bus.

The factor k can be determined from

$$k^i = \frac{(Q^i)^t \nabla P_L^i}{(\nabla P_L^i)^t (\nabla P_L^i + [P^i] P^i)} \quad (13)$$

The estimated value of k may result in violation of the reactive or voltage constraints at one or more buses during the iterative process. If the calculated value of k is outside the reactive limits for bus j , the minimum or maximum reactive limit is substituted accordingly. If the voltage constraints are violated, the calculation of k is repeated with a reduced value of k , obtained from

$$k' = Tk$$

$$\text{where } T = \frac{|dE_j^{\text{desired}}|}{|dE_j|}$$

The steps in the procedure are:

- 1) recalculate the d and θ coefficients using the load flow results obtained with the economic real power generation schedule.
- 2) compute the gradient vector ∇P_L
- 3) calculate k factor
- 4) calculate a new reactive power schedule
- 5) check the reactive powers scheduled against the minimum and maximum capability limits; if limits are exceeded, modify the reactive power schedule to satisfy constraints.
- 6) solve the load flow with the new reactive power schedule
- 7) check voltages of all buses against minimum and maximum allowable voltages; if voltage limit are exceeded reduce the value of k accordingly so that all bus voltages will be within specified limits and return to 4.

If the bus voltages are within limits, a new real power dispatch is calculated followed by a reactive dispatch. The process is continued until no further reduction in the total production cost can be obtained.

Optimal Power Flow

An optimal load flow is a load flow in which an objective function (total operating costs or some other quantity) is minimized subject to the ordinary load flow constraints or any other additional constraints. When the objective function represents the operating cost, the solution is an exact economic dispatch. Much of the work in optimal power flow subject to equality and inequality constraints has been based

upon the Kuhn and Tucker theorem of nonlinear programming.

The Kuhn-Tucker theorem gives the necessary conditions for the minimum of a given function $F(x)$ of a vector variable x under the equality and inequality constraints

$$G(x) = 0 \quad (14)$$

$$H(x) \leq 0 \quad (15)$$

assuming proper convexity for the functions, as

$$dL = 0, \text{ where}$$

$$L = F(x) + \lambda^T G(x) + \mu^T H(x) \quad (16)$$

$$\lambda_i \text{ arbitrary, } \mu_i \geq 0$$

$$\text{and } \mu_i H_i(x) = 0 \quad (17)$$

The multipliers λ_i and μ_i are the dual variables associated with the equality and inequality constraints. Condition (17) implies that $\mu_i = 0$ if constraint $H_i(x)$ is not reached, and $\mu_i > 0$ otherwise.

The original work of Carpentier on optimal power flow based upon Kuhn-Tucker theorem can be summarized as follows.

In a power system of N nodes there may be a production P_i , Q_i and a consumption C_i , D_i of active and reactive power, respectively, at the i th node having voltage V_i and phase angle θ_i . For pure production node $C_i = D_i = 0$, and for pure consumption node $P_i = Q_i = 0$.

An intermediate case is $P_i = 0$ and $Q_i \neq 0$.

Calling I_i and K_i the real and reactive power injected into the network at node i , the load flow equations are

$$I_i(\theta, V, Y) - P_i + C_i = 0 \quad (18)$$

$$K_i(\theta, V, Y) - Q_i + D_i = 0 \quad (19)$$

The related variables S_i^A , P_i , Q_i , V_i and θ_i are subject to upper (M) and lower (m) constraints of the form

$$P_i^A + Q_i^A - S_i^{A,M} \leq 0 \quad (20a)$$

$$P_i^M - P_i \leq 0 \quad (20b)$$

$$Q_i - Q_i^M \leq 0 \quad (20c)$$

$$Q_i^M - Q_i \leq 0 \quad (20d)$$

$$V_i - V_i^M \leq 0 \quad (20e)$$

$$V_i^M - V_i \leq 0 \quad (20f)$$

$$\theta_i - \theta_A - T_{iA} \leq 0 \quad (20g)$$

Let λ_i and μ_i denote the dual variables associated with the equality constraints (power flow equations) (18) and (19) and let the dual variables M_i^A , m_i^A , e_i^A , e_i^M , u_i^A , u_i^M , t_{iA} be associated with the inequality constraints (20a) through (20g), respectively. The function is then written as

$$L = F(P_1, \dots, P_N) + \sum_i \lambda_i (I_i - P_i + C_i) + \sum_i \mu_i (K_i - Q_i + D_i) + \sum_i M_i^A (P_i^A + Q_i^A - S_i^{A,M}) + \sum_i m_i^A (P_i^M - P_i) + \sum_i e_i^A (Q_i - Q_i^M) + \sum_i e_i^M (Q_i^M - Q_i) + \sum_i u_i^A (V_i - V_i^M) + \sum_i u_i^M (V_i^M - V_i) + \sum_i t_{iA} (\theta_i - \theta_A - T_{iA}) \quad (21)$$

Setting $dL = 0$ the following group of optimization equations results for a node with both production and consumption. For a pure consumption node, (22) and (23) do not exist.

Differentiation with respect to P_i and Q_i

$$\lambda_i = \frac{\partial F}{\partial P_i} + 1 M_i^A P_i - m_i^A \quad (22)$$

$$\mu_i = 2 M_i^A Q_i + e_i^A - e_i^M \quad (23)$$

Differentiation with respect to θ_i and V_i

$$\lambda_i \frac{\partial I_i}{\partial \theta_i} + \sum_A \lambda_A \frac{\partial I_A}{\partial \theta_i} + \mu_i \frac{\partial K_i}{\partial \theta_i} + \sum_A \mu_A \frac{\partial K_A}{\partial \theta_i} + \sum (t_{iA} - t_{A,i}) = 0 \quad (24)$$

$$\lambda_i \frac{\partial I_i}{\partial V_i} + \sum_A \lambda_A \frac{\partial I_A}{\partial V_i} + \mu_i \frac{\partial K_i}{\partial V_i} + \sum_A \mu_A \frac{\partial K_A}{\partial V_i} + u_i^A - u_i^M = 0 \quad (25)$$

In addition, the power-flow equations (18) and (19) and the exclusion equations

$$M_i^A (P_i^A + Q_i^A - S_i^{A,M}) = 0 \quad m_i^A (P_i^M - P_i) = 0$$

$$e_i^A (Q_i - Q_i^M) = 0 \quad e_i^M (Q_i^M - Q_i) = 0 \quad (26)$$

$$u_i^A (V_i - V_i^M) = 0 \quad u_i^M (V_i^M - V_i) = 0$$

$$t_{iA} (\theta_i - \theta_A - T_{iA}) = 0$$

must be satisfied at the optimum.

At load buses, the unknowns are θ_i , V_i , λ_i , and μ_i ; and possible non zero dual variables due to the constraints in (20); there are four corresponding groups of equations 24, 25, 18, 19, and 26 for the non zero dual variables.

For each generator node there are six principal equations 22, 23, 24, 25, 18, 19, and 26 for the non zero dual variables; if no constraints are encountered the unknowns are θ_i , V_i , λ_i , μ_i , P_i , and Q_i ; if a constraint is encountered, the principal variable becomes known, and the dual variable unknown.

The above formulation is characterized by the load flow equations being submerged in the total, as equality constraints.

At the optimum the dual variables λ_i and μ_i measure the marginal or incremental cost of active and reactive consumption at node, i , i.e.

$$\lambda_i = \frac{\partial F}{\partial c_i} = \frac{\partial F}{\partial c_i} \quad (27)$$

$$\mu_i = \frac{\partial F}{\partial b_i} = \frac{\partial F}{\partial b_i} \quad (28)$$

Similarly, the dual variables $\mu_i, \mu_j, \mu_k, \mu_l, \mu_m, \mu_n$ and μ_o measure the marginal cost associated with the constraints (20a)-(20g), respectively. For example, the dual variable

$$\mu_i = -\frac{\partial F}{\partial V_i} \approx -\frac{\partial F}{\partial V_i} \quad (29)$$

relates the saving ΔF to a relaxation ΔV_i in the upper voltage bound V_i^M .

The marginal cost, (27) and (28), thus provides a logical basis for tariffification, whereas the marginal costs of the type represented by (29) point out the equipment constraints and thus aid in system expansion studies.

The solution procedure employed by Carpentier was Gauss-Seidel. The convergence behavior proved to be much more difficult and erratic than was initially recognized. A different computational approach was developed at BPA taking advantage of their existing power-flow program employing Newton's method. This approach, which appears to be of considerable generality, consists of making vector adjustments of the primary control variables in accordance with the information derived from the dual variables associated with a feasible but not necessarily optimum solution. Since all of the control variables are adjusted simultaneously, the program converges to an optimum solution in such the same manner as it does to a feasible solution. The procedure can be summarized as follows:

Let x be the vector of all unknown variables which consist of V and θ on P, Q nodes, and θ on P, V nodes; p the vector of fixed parameters, consisting of P, Q nodes and θ on the slack bus; u the vector of control parameters such as voltage magnitudes on P, V nodes, transformer tap ratios and generator real powers P available for economic dispatch.

The minimum of the function f , with u as independent variable,

$$\min_u f(x, u) \quad (30)$$

subject to the equality constraints of the load flow equations 18 and 19 which combined are denoted as

$$g(x, u, p) = 0 \quad (31)$$

is to be found.

The Lagrangian is written as

$$L(x, u, p) = f(x, u) + \lambda^T g(x, u, p) \quad (32)$$

The set of necessary conditions for a minimum are

$$\frac{\partial L}{\partial x} = \frac{\partial f}{\partial x} + \left[\frac{\partial g}{\partial x} \right]^T \lambda = 0 \quad (33)$$

$$\frac{\partial L}{\partial u} = \frac{\partial f}{\partial u} + \left[\frac{\partial g}{\partial u} \right]^T \lambda = 0 \quad (34)$$

$$\frac{\partial L}{\partial \lambda} = g(x, u, p) = 0$$

which is equation (31)

Equation 33 contains the transpose of the Jacobian matrix of the power flow solution by Newton's method. For any feasible, but not yet optimal, power flow solution, equation 31 is satisfied and λ can be obtained from (33). Then $\frac{\partial L}{\partial u}$ can be computed from (34). This vector

has an important meaning; it is the gradient vector ∇f which is orthogonal to the contours of constant values of the objective function.

Equations 33, 34 and 31 are nonlinear and can only be solved by iteration. The simplest iteration scheme is the method of steepest descent. The solution algorithm can be as follows:

- 1) Assume a set of control parameters u .
- 2) Find a feasible power flow solution by Newton's method. This yields the Jacobian matrix for the solution point in factored form (upper and lower triangular matrices), which is computationally equivalent to the inverse or transposed inverse.

- 3) Solve (33) for λ

$$\lambda = -\left(\left[\frac{\partial g}{\partial x} \right]^T \right)^{-1} \frac{\partial f}{\partial x} \quad (35)$$

This amounts to one repeat solution of a linear system for which the factored inverse is already available from step 2.

- 4) The gradient is computed as

$$\nabla f = \frac{\partial f}{\partial u} + \left[\frac{\partial g}{\partial u} \right]^T \lambda \quad (36)$$

The gradient, ∇f measures the sensitivity of the objective function with respect to changes in u , subject to the equality constraints (31).

- 5) If ∇f is sufficiently small, the minimum has been reached. Otherwise find a new set of control parameters from

$$u^{new} = u^{old} + \Delta u \quad \text{with } \Delta u = -c \cdot \nabla f \quad (37)$$

and return to step 2

Equation 37 is one of several possible correction formulas. When (37) is used, much depends on the choice of the factor c . Too small a value causes slow convergence, whereas too high a value causes oscillations around the minimum.

The inequality constraints on control parameters can be handled by assuring that the adjustment algorithm (37) does not send any parameter beyond its permissible limits. If the correction Δu_i from (37) would cause u_i to exceed one of its limits, u_i is set to the corresponding limit. Even when a control parameter has reached its limit, its component in the gradient vector must still be computed in the following cycles because it might eventually back off from the limit. In equality constraints on dependent variables, such as voltage limitation P, Q nodes, are called functional constraints and are more difficult to handle. The simplest approach is the penalty method in which the objective function is augmented by penalties for functional constraint violations. This forces the solution back sufficiently close to the constraint. With the penalty method the objective function f must be replaced by

$$f \text{ with penalties} = f(x, u) + \sum w_j \quad (38)$$

where a penalty w_j is introduced for each violated functional

constraint. Given a constraint such as $V_i^{min} \leq V_i \leq V_i^{max}$, the penalty function becomes

$$w_j = \begin{cases} s_j (V_i - V_i^{max})^2, & \text{when } V_i > V_i^{max} \\ s_j (V_i - V_i^{min})^2, & \text{when } V_i < V_i^{min} \end{cases} \quad (39)$$

In this method the constraints are being treated as "soft" constraints. The steeper the penalty function (the higher the s_j) the closer the solution will stay within the rigid limit, but the worse the convergence will be.

On nodes with reactive power control, often two inequality constraints must be observed simultaneously

$$V^{min} \leq V \leq V^{max} \quad (40)$$

$$Q^{min} \leq Q \leq Q^{max} \quad (41)$$

One of which is a parameter constraint and the other a functional constraint, depending on whether V or Q is chosen as control parameter.

The method as described above can handle a variety of optimization problems through a proper choice of the objective function. In the case of optimal real and reactive power flow, the objective function can be defined as

$$f = \sum K_i (P_i)$$

where K_i is the production cost for the power P_i

The slack node must be included in the sum with $P_i = P_i(V, \theta) + C_i$.

In the case of optimal reactive power flow the objective function is

$$f = P_i(V, \theta)$$

Since all other generations and loads are fixed in this case, minimizing the real power P_i is identical with minimizing total system losses. Similarly, any other objective function can be selected depending on the optimization problem at hand.

The optimization problems have also been solved by non-linear programming techniques. The power system optimization problem formulated as a constrained minimization problem is transformed into an unconstrained problem. One of the powerful methods for unconstrained minimization that are available can then be applied to obtain a solution. One of the transformations that have been successfully applied is due to Powell. The original objective function $f(x)$ to be minimized subject to the constraints $g(x) \geq 0$ is transformed into

$$F(x, r, s) = f(x) + \sum_{i=1}^m \frac{(g_i(x) + s_i)^2}{r_i} \quad (41)$$

where s_i and r_i are constants during each sequential minimization and inequalities are only included when violated. The actual minimization required in each equation is performed by a function minimization technique such as that of Fletcher and Powell or Fletcher and Reeves.

The equality and inequality constraints $g(x)$ in equation 42 are the power-flow equations and the upper and lower limits to the voltage magnitude and real and reactive power inputs of each bus. The objective function $f(x)$ is selected according to the problem at hand.

The feasibility of applying the above procedure in various optimization studies has been demonstrated using sample power systems of moderate to small sizes.

However, in its application to large practical size power systems problems associated with reliability of convergence, speed of solution and core storage can be expected.

Voltage and Reactive Power Optimization

The control of voltage and reactive power is required in order to maintain the service quality of electric energy supply to customers and reduce transmission losses. An optimum allocation of reactive bus power can maintain system voltages within proper tolerance during normal and various contingency conditions as well as reduce operating costs through the reduction of transmission losses.

The ability to maintain acceptable voltage levels during contingencies is usually of greater concern than system loss reduction and therefore long range network reactive planning is generally based on the voltage maintenance requirement. The system loss at a given load and generation condition, the reactive power flow, and the system voltages are, however, inter-related. The reactive power flow is mainly determined by system voltages and at optimum voltage level the system loss is minimum. Thus, controlling reactive power flow to maintain system

voltage requirement will automatically lead to minimum system loss. Similarly, minimizing system loss will lead to optimum voltage distribution and reactive flow.

Voltage and reactive power optimization can be carried out using the methods described under optimal power flow, selecting an appropriate objective function reflecting the type of optimization desired subject to the specific constraints.

However, if the main objective is the allocation of reactive sources in long range system planning, something less than a full optimization as to reduce the computational effort may be in order. Optimized use of reactive compensation e.g. capacitors can maintain voltage levels in contingency conditions and reduce system losses. Two of the methods of allocating capacitor in a transmission system that seem to be practical are outlined below.

The minimum amount of reactive correction required in a transmission system in order to control the voltage drops during critical outage cases can be determined by the method of linear programming. The method is based on the approximation that for relatively small changes, the change in bus voltage magnitude for a change in reactive generation is given by

$$\Delta E_i \approx \sum_j X_{ij} \Delta Q_j \quad (42)$$

where ΔE_i is the per unit change in bus voltage magnitude at bus i , X_{ij} is the bus reactance matrix element and ΔQ_j is the change in reactive generation at bus j .

One equation represents each bus for each contingency being considered.

The objective function to be minimized is the sum of the $c_j \Delta Q_j$'s

The weighting factor, c_j , is used to penalize buses where reactive devices cannot be installed for either economic or physical reasons.

The reactive support is added on the system so as to result in a rise in voltage at each bus greater than or equal to the voltage drop less the allowable drop at that bus resulting during the contingency case.

Therefore, the linear programming problem may be stated as

$$\text{minimize } \sum_j c_j \Delta Q_j \quad (43)$$

$$\text{subject to } \Delta E_i \geq X_{ij} \Delta Q_j \quad (44)$$

$$\text{and } 0 \leq \Delta Q_j \quad (45)$$

where ΔE_i is the per unit change in voltage that must be corrected during contingency n .

Equation 45 is based upon a linear approximation. Therefore, power flows must be made of all the cases under investigation to determine whether or not the voltage constraints have been satisfied. If the voltages are not within an acceptable tolerance, the linear programming is repeated and the voltage constraints checked. This is continued until all voltages are within the acceptable tolerance.

The method to be described next also relies on linear approximation. In the bus impedance frame

$$E_{bus} = Z_{bus} I_{bus} \quad (46)$$

The change in bus voltage after the addition of a capacitor unit, represented as an injected current, ΔI is

$$\Delta E_{bus} \approx Z_{bus} \Delta I \approx Z_{bus} (E_{bus} Y_{cap}) \quad (47)$$

Since the purpose of adding capacitors is to raise the voltage level, the best bus to which a capacitor should be added can be defined as the one that causes the maximum overall voltage rise in all the low-voltage buses when a capacitor is added to it. When adding such a capacitor at bus k , the injected current ΔI_k will be

$$\Delta I_k = \frac{\Delta Q_k}{E_k} \quad (48)$$

This injected current will cause a voltage change in all other buses that can be approximated as

$$\Delta E_i = Z_{ik} \Delta I_k = Z_{ik} \left(\frac{\Delta Q_k}{E_k} \right) \quad (49)$$

A sensitivity measure can now be associated to each bus defined as the sum of the changes in voltages of all low-voltage buses.

$$\sum \Delta E_i = \sum Z_{ik} \left(\frac{\Delta Q_k}{E_k} \right) \quad (50)$$

where the summation is to be taken over all low-voltage buses. This sensitivity measure is dynamic, since the number of low-voltage buses decreases as capacitors are added to the system. For every voltage profile, the test is performed and the bus with the highest sensitivity as defined by (51) is selected for the next capacitor addition. Continuation of the process should converge to a solution resulting in adequate voltage profile for the least amount of installed capacitors.

APPENDIX P DC LINE REPRESENTATIONS

General Electric Model

The General Electric Company's power system load flow program has the capability of handling two-terminal DC lines.

Input parameters include:

- DC line resistance
- Commutating reactance
- AC base voltage
- Number of bridges
- Final rectifier delay angle and inverter margin angle
- DC line data-voltage
 - current
 - line loss
 - power for rectifier and converter
- AC load for rectifier and inverter at both sides of the converter transformers

A solved power flow can then be utilized as input for the power system stability program. The following schematic diagram depicts the DC model and control parameters.

The DC terminal voltage signals DP and DDP are determined from the AC Commutating-bus voltages at the rectifier and inverter ends, respectively. They include the effect of commutating reactances.

The program allows for selections of current control or power modes of operation. The program has optional capability to model frequency control and bypass and restart control dynamics.

Westinghouse Stability Program

The Westinghouse stability program has the capability of representing twelve (12) two terminal monopolar lines (bypolar lines are represented by grouping two (2) monopolar lines). The program provides independent control for each monopolar line with the ability to simulate DC faults and to modulate DC power flow.

The model attempts to simulate flows at dc terminals during and after system disturbances to determine positive sequence voltage magnitudes and angles. Two sets of equations are required: one set of algebraic equations for AC and DC load flow calculations which determine AC system voltage and converter firing and commutation angles compatible with the desired DC line current; and a second set of differential equations associated with line current control and possible auxiliary control signals.

The program assumes two possible dc line modes of operation. The preferred mode when the dc line current is equal to that ordered by the line current controller. In this mode the in-

verter will operate at its minimum angle of extinction and the rectifier will operate at a firing angle (≥ 0) compatible with the inverter voltage and the voltage drop in the line. If the voltage with minimum firing angle is too low to permit this mode of operation a second mode of operation is considered in which the rectifier operates at a minimum firing angle, and the firing angle of the converter is adjusted to be compatible with the rectifier voltage and the line drop at a reduced dc line current.

The basic relationships for combined load flow calculations consist of a voltage regulation equation for each converter, a current equation for each converter, and a line voltage drop equation. Equations for commutation and firing angles and power factor angles are required at each converter.

Arizona Public Service Stability Program

There is currently a EPRI-sponsored project involved with, among other things, incorporating a dc line model into the Arizona Public Service Company power flow and transient stability programs. Progress reports on this project lend the following information.

The equivalent circuit for the model of the two-terminal DC line is shown below. The converter represents a multiple bridge. The valve drops, smoothing reactor and equivalent commutating resistance are shown in this schematic.

TWO-TERMINAL DC LINE MODEL

There are two input modes for the AC-DC converter model, the power mode and the current mode indicating the primary controlled variable in each case. There are three operating modes for the converter controls: constant firing angle, constant current or power, and constant extinction angle.

The solution of the line equations consist of obtaining all AC and DC quantities from the commutating voltages at both ends of the line and firing angle as computed in the converter control system simulation.

Commonwealth Edison Model

Commonwealth Edison Company, motivated by an interest to analyze the inclusion of HVDC transmission in their power system, has developed a method of including equations for DC converters and transmissions lines directly into their existing Newton AC

system power flow. The salient feature of method is that it solves the AC and DC portions of the system simultaneously, thus eliminating the need to alternately readjust and re-solve the DC and AC networks. The program has the capability of handling any number of two-terminal components of the AC system.

This work represents the first step in the overall inclusion of HVDC into the Commonwealth Edison package of power systems analysis programs. Future work will involve adding appropriate HVDC representations into fault study and transient stability programs as well as additional refinements in the power flow program.

RELIABILITY ANALYSIS

Reliability is a key consideration in the planning, design and operation of electrical power systems. Many of the present methods of reliability evaluation of generation systems employ sophisticated probabilistic techniques to develop specific indices of system adequacy. Yet most of the current methods of transmission system reliability evaluation employ simple deterministic criteria relying on the human experience and judgment. This section will discuss methods presently being developed and utilized which employ probabilistic techniques to the reliability analysis of the transmission system or to the composite bulk power system (generation and transmission) as a whole.

Each of the methodologies must contain an algorithm to adequately represent power flows within the electrical network. Due to the number of separate power flow calculations required in a reliability assessment for multiple transmission outage conditions, most techniques avoid the use of the classical AC load flow solutions due to the excessive computation time requirements and computer core requirements. However, faster AC solution techniques are under development, stimulated by the desirability to retain the proper representations of MVA flows and voltages.

Presently a more acceptable approach is the DC solution. Although sacrificing the reactive and voltage representations inherent in the AC flow solution, it provides the solution speed necessary for practical applications within these reliability evaluation techniques.

The fastest solution applied is that of the so-called transportation model. It obtains a very rough linear approximation of power flows based on the location of power sources and sinks, transmission routes and capabilities. Such a model merely satisfies the balance-of-power constraints at each bus (Kirchoff's current law), but ignores the electrical impedances of the system.

Most of the transmission reliability assessment methods represent the evaluation of various transmission facility outages by applying an independent outage probability or failure rate for each transmission facility. Such rates and probabilities are generally derived from historical data bases. Yet such representations do not accurately represent reality as they avoid dealing with the common mode outages, such as the simultaneous outage of two or more lines on a common right-of-way. Consideration is presently being given to such representations by means of conditional probability approaches.

Generation unit outages, where considered, are represented by either applying average unit unavailability rates, or by individual unit outage either chosen by judgment or selected by a random selection routine.

Finally of the seven methods now to be discussed, each is geared to provide either a system-wide reliability index or a local or station reliability index. The system-wide index provides a concise description of the overall system adequacy, but does little to indicate what the trouble spots are, and thus where improvements can be made. The local or station index on the other hand can locate trouble spots and rank them in order of severity, yet provides no precise indication of overall system adequacy.

Of the seven methodologies to be discussed here, the first five are geared toward providing station indices while the remaining two evaluate reliability on a system-wide basis.

PSE&G-WESTINGHOUSE MODEL

In the mid 1960's Public Service Electric and Gas Company and the Westinghouse Electric Corporation jointly developed analytical techniques employing probability theory to calculate critical reliability indices which indicate the level of the frequency and duration of customer interruptions from basic system component parameters. The resulting program calculates a reliability measure at each specified load bus, then calculates measures of average reliability provided to all the customers by the system.

The program requires a set of system component outage rates which are generally obtainable from historical records; permanent and temporary forced outage rates and maintenance outage rates. Average component return-to-service times (permanent forced outage repair times, maintenance outage down times and manual switching

times) are required for the various outage classifications.

In addition, the program has a two-state weather model. That is, component outage rates are entered for both normal and stormy weather periods which are weighted by the typical historical durations of such weather conditions.

The user, through the preparation or visualization of system reliability diagrams which display the systemic relation of various components between the source and the load bus (study bus), develops probability "success" and "equivalent" expressions which are suitable for the computer program to facilitate system reliability calculations.

The program can then calculate any of several optional reliability measures for given load busses and an average for all customers served by the system. The program, as reported in available references is capable of handling up to 999 load busses or points at which the reliability is to be calculated and up to 999 different components.

BILLINTON/BHAVARAJU APPROACH

The IEEE papers, "Transmission Planning Using a Reliability Criterion, Part I: A Reliability Criterion", 69TP121-PWR, and "Transmission Planning Using a Reliability Criterion, Part II: Transmission Planning", 70TP156-PWR by R. Billinton and M. P. Bhavaraju are the basis for a transmission reliability evaluation computer program.

The program calculates a station reliability index for each station studied in terms of a probability and frequency of failure at the station bus. Failure is defined as either inadequate generation capacity, unacceptable voltage levels or station isolation. The program requires the following

input data:

- all data required for the AC load flow analysis
- VAR limits at generating buses, voltage limits at all buses
- maximum capacities of lines and transformers
- distribution of the system load at various buses and the normalized load duration curves
- the generation schedule at the increasing load levels being considered in the analysis
- failure and repair rates of system generating units, lines and transformers.

The AC load flow is solved for all possible outage conditions up to a maximum of two simultaneous, independent outages. For each such outage condition, there is a maximum load at each bus which can be supplied without failure. The probability of the load at a bus exceeding this maximum is combined with the probability that the capacity is insufficient to meet the total system load, to determine the overall probability of failure at each bus.

This risk can then be compared to the acceptable planning risk index to determine the direction of future plans or remedial actions.

The program, in its present form, is not suitable for practical electric power system analysis. Besides having system size limitations (30 buses, 200 lines/transformers) the existing method of solving AC load flows for each outage condition requires high computation times. Also there is no capability to represent realistic system operating flexibility such as generation redispatching to relieve facility overloads.

Some modifications which might be suggested to make this model a workable planning/operating tool would be to:

- go to a DC solution to speed computation times
- expand program capabilities (buses/lines)
- add logic to be selective about outages to be analyzed
- add capability to represent multi-terminal lines and common mode outages
- add the capability to redispatch system generation to alleviate voltage and overload problems.

PCAP

Power Technologies Incorporated's Contingency Analysis Program determines reliability indices of a specific transmission network with respect to forced outages of circuits and generating units.

This program uses a linearized real or simplified power flow to identify transmission overloads. It has the ability to select the specific outages most likely to produce system failure conditions by calculating a sensitivity factor which relates power flows to outage cases. Load flow studies are performed for each suspected outage, checked for failures, and if failures occur, a calculation of the probability and frequency of occurrence is performed. A system failure can occur if:

- insufficient generation to supply the load
- transmission element is overloaded
- bus voltage is unacceptable
- load bus is isolated from the system.

When overloaded conditions occur the program has the capability to redispatch generation and redistribute flows via phase shifter operation to relieve the overloads. It also has the capability to compensate for loss of generation. When possible overloads occur, individual bus loads will be curtailed until all circuit overloads are relieved. The contingency probability, its frequency, and the amount of load curtailed for the contingency are then computed and combined to form a composite system reliability index. Load isolation at individual buses, or system separations, is treated as a function of the probability of occurrence of overlapping outages.

A LCI (load curtailment index) can be calculated to specify the amount of load curtailed per year in reference to the amount to be served.

The Northeast Power Coordinating Council (NPCC) has contracted PTI to make some useful modifications and expand the program from its existing 375 bus capability. It appears the program will be a viable production grade planning and operating tool.

There are some shortcomings to this technique worth mentioning. The loss of load calculated as the result of transmission outages occurs when the specified outages result in an isolated portion of the system without sufficient capacity to cover its load. Hence the program could not produce results suitable for use in planning a system to meet a given reliability level based on loss of load probability (LOLP). Also the results obtained for the probability of load exceeding generation are only for one load level and include all generation. Hence the program results are not compatible with existing LOLP methodologies.

FLORIDA POWER CORPORATION APPROACH

This approach presently in the program developmental stages, applies a method of automatically combining high-speed contingency linearized decoupled AC load flow results with stochastic probability methods to obtain a reasonable quantitative estimate of overall power system reliability. The results are reliability measures of the power system's ability to provide adequate power supply to all load buses.

At the present time the method models all single contingency line, transformer and generator outages. However, present plans are to expand the program to include protection control group operations and common mode outages in the near future. Power flows and voltages are calculated for each contingency case at the peak load level. Emergency redispatching is implemented to attempt to alleviate any overloaded lines prior to determining loss of load. A series of checks is performed to see if any loss of load would occur for each contingency either due to a break in continuity of the system or due to load reductions necessary to alleviate overloads or inadequate voltages. Each such case of loss of load is defined as a service failure mode.

Each case is rerun at lower load levels and rechecked until all load levels to be represented have been reviewed. The lowest load level at which each contingency causes a service failure is called the critical load level. Stochastic parameters relating to such load level and to the outage itself are then utilized to calculate the parameters reflecting the impact of that service failure mode on the system. Since the resulting service failure mode probabilities are mutually exclusive, the results may be added to get total system reliability levels as well as individual bus reliability measures.

Again the salient features of this proposed approach are (1) the utilization of a high-speed contingency load flow technique to provide AC network calculations for the contingency cases to be performed, and (2) the calculation of customer related indices.

BONNEVILLE POWER ADMINISTRATION APPROACH

The Bonneville Power Administration has outlined their prospective approach to the problem of transmission reliability evaluation. Their program would utilize their established fast-decoupled power flow solution to evaluate system conditions during highly probable contingencies. The load flow could be solved for real power only with or without iteration, or real and reactive power with iteration. The solution for each contingency is checked for overloads or voltage violations. Problems would be solved by generation shift and/or load drop or possibly line switching in special cases. Multiple contingencies could then be represented linearly where required using sensitivity factors. The results would be presented in three forms:

1. Each contingency which causes a problem, the contingency's frequency and duration, and the problem it causes;
2. Each problem, the contingencies which cause it, the corresponding magnitude of the problem, and the frequency and duration of various levels of magnitude;

3. If generation shift/load drop are used; each node at which the corrective action is taken, the contingency which causes the need for corrective action, the contingency's frequency and duration, and an expected MW-bus/year of corrective action.

The program lacks a load model and uses only a constant seasonal peak. Yet it is proposed that the resulting probabilities in this method be scaled in proportion to exposure to the peak.

TRANSAR

The Transmission Outage Probability Adjustment to Area Reliability (TRANSAR) was inspired by a Commonwealth Edison paper, "A Reliability Approach to Interconnection Planning", IEEE T75-058-3, by Landgren, Anderson and White which suggests a method for determining a measure of reliability for a given area based upon the emergency import capability which can be probabilistically expected to exist between that area and its neighbors through transmission interconnections. TRANSAR is not a formal program at the present time, but a consolidation or interfacing of two existing reliability evaluation programs currently utilized by planning engineers in the PJM (Pennsylvania-New Jersey-Maryland) power pool. The interfacing would presently involve manual probability calculations. If this methodology were to prove desirable, the manual process could be automated (computerized) for ease of use.

For a given system area with probabilistic load and generation availability representations the PJM generation system reliability index program can be used to develop a table of transmission tie size capability versus probability of need. (Need meaning what is required to serve the load with a specified reliability index).

At the same time, the transmission limitations program uses linear superposition factors to calculate the MW-import capabilities into the area for various combinations of critical transmission outages to which an associated probability of occurrence is attached. The results are a set of transmission import capabilities with associated probabilities of occurrence.

The needs' and the capabilities' probabilities are then merged to form an overall area probability of loss of load. However, a determination of the acceptability of the area's reliability levels would require the establishment of benchmark reliability levels.

The two programs are production-type programs capable of handling large systems within reasonable time durations. The major limitations to practical utilization are the rigors of performing the manual interface and the general acceptability of the results; that is, there is no indication of the loss-of-load frequency and duration. Further, the method does not depict local problems which may exist within the area, rendering the necessity

for additional load flow analysis to get the complete picture.

PTI MULTI-AREA GENERATION SYSTEM RELIABILITY PROGRAM

The PTI "Multi-Area Generation System Reliability Program" is a technique for the evaluation of the reliability of serving the load within a number of interconnected load-generation areas. The present program limitation is thirty such interconnected areas. These areas may be interconnected by any combination of transmission links. These links are described by capacity values with associated probabilities of existence reflecting the line outage probabilities.

The method in effect expands an existing method of calculating generator system reliability indices to the general case of N interconnected load/generation areas. Area generation reserve margin distributions are attained using established existing algorithms for analyzing area load probability and generation availability probability distributions. The various transmission links are described by capacity states with associated probabilities of existence. This method uses linear flow techniques to model the transmission interconnections allowing lines to be loaded to their capacities in keeping with Kirchoff's current law but without regard to Kirchoff's voltage law. The method also employs an efficient graph theory algorithm to segregate the failure states by finding the critical minimal cuts in the network, a technique which greatly reduces the number of probability evaluations required.

The probabilities of failure to supply the loads are computed by evaluating the various event probabilities associated with these critical minimal cuts. The results are reliability measures (probabilities of failure to meet loads) for each individual area and the total system, as well as the computation of the probability that each link is a member of the critical minimal cut. However, the program cannot provide information on reliability status of various load buses in each area.

The program also provides the capacity to handle power pool policies with respect to load-loss and no-load-loss sharing policies between the interconnected areas.

Because the program utilizes this linear flow technique, it does not use network impedances to determine network flow conditions, and generally results in nonrealizable flow patterns. Yet the inclusion of a load flow model at this time would present an extreme complexity due to the exponential nature of the solution technique.

APPENDIX H
INSTITUTIONAL ISSUES

Transmission planning on a regional scale presents institutional problems, which, although not insurmountable, must be resolved in order to satisfactorily implement such joint plans and maintain the levels of reliability achieved without coordinated regional planning. Among these problems are:

1. Developing regional plans on a consistent reliability criteria basis.
2. Determining appropriate cost sharing guidelines among multi-company participants.

It must be understood that the above mentioned problems have not prevented the implementation of many multi-company projects in the past. Usually such joint ventures involved adjacent systems or several or all members of an established power pool where consistent criteria exist and cost allocation guidelines have established precedents or can be satisfactorily agreed upon.

I. Consistent Reliability Criteria

All utilities plan system reinforcements on the basis of a defined acceptable level of customer-service reliability. There are some variations among various systems in quantifying just what is "acceptable". By and large, it does appear that although all reliability criteria are not identical they are essentially compatible. The National Electric Reliability Council (NERC) has been addressing this issue and it is expected that regionwide consistent reliability criteria could be developed with due recognition of certain disparate geographic and system characteristics.

In transmission planning most systems have largely applied deterministic techniques. Therefore, the attainment of a specified reliability level is measured through the test of a regional network to determine whether it can withstand the defined contingency conditions. A uniform regionwide criteria would involve the resolution of any major disparities in such contingency guidelines and the appropriate facility ratings to be applied under such contingencies.

II. Cost-Sharing Guidelines

This cost allocation issue may well be the most difficult to resolve for any joint project on a regional basis. As previously stated joint agreements on various regional transmission projects are not uncommon but generally involve systems adjacent to each other or belonging to the same power pool. It should also be pointed out that these joint transmission facilities are integrated with a vast existing transmission network consisting primarily of circuits owned and operated by various individual companies. The joint ventures have in practice been planned and constructed on the basis that the benefits and obligations of all participants can be readily identified and equitable cost sharing agreements can be satisfactorily reached in accordance with such respective benefits. As the needs for regional transmission reinforcements, the related regulatory requirements and the regional systems themselves all become increasingly complex, the appropriate identification of each

party's rights and obligations may also become more difficult. It appears that improved methods are required to provide more rational and pragmatic guidelines for cost allocations. Such methods must encompass an appropriate technical basis for determining the usage each participating company makes of various transmission facilities of a given network relative to the other participants, and associated philosophy to translate the usage information to cost responsibility assignable to each participant.

One such method to assess changes in future use and to reallocate cost responsibilities of an existing EHV project has been adopted for contractual applications by a group of EHV transmission co-owners of a eastern power pool. Essentially the method applies a modified version of a "power flow superposition" analysis. The flow on any transmission circuit in a given network is a function of the load and generation of each company within the network. To prevent the use by one company of those transmission facilities for which it has no entitlement, such facilities will be disconnected from the network when evaluating the uses by this company. In the case of joint transmission facilities, they will be represented as reduced-capacity circuits to reflect this company's shares of such joint rights. In making the use evaluation for each participant, only the loads and generation of this company are represented; the rest are set to zero. Load flows of the modified network are then solved. The total usage is determined by adding up the amount of MW flow on each circuit multiplied by the mileage of each circuit, expressed in MW-miles. Similarly, the total con-

tribution can be determined by the rating share of each company on any circuit multiplied by its mileage, also expressed in MW-miles. "Overuse" or "underuse" is thereby determined by subtracting the total contribution of each company from its total usage, and the associated "cost responsibility" can be ascertained. This approach could also be adapted to evaluate each participant's cost responsibility for a new joint transmission project.

III. Other Considerations

Other institutional issues which may have to be considered for regional transmission planning are:

- a. Coordination of future transmission voltage levels
- b. Coordinated operational and maintenance guidelines to implement joint plans.
- c. Means for cost allocations for inter-regional and trans-regional capacity and energy wheeling. The use-measuring concept described above may also be adapted for such purposes.

APPENDICES
OF
University of Florida

APPENDIX A: ROUTE IDENTIFICATION

I. BASED ON THE PROGRAM POWER

Using a weighted sum of the impact variables given in Table 1a a graph is constructed where the node numbers are the cell numbers and the numbers associated with the arcs are the weighted costs, including temporal variations. Applying a searching algorithm proposed by Dijkstra at least cost path can be identified between pre-specified beginning and ending cells. In summary, the application of Power involves the following basic steps:

1. Define geographical area through which corridors are required.
2. Decompose area into cells of appropriate size.
3. Develop a set of inventory variables that adequately describe the character of each cell.
4. Develop a set of variables that adequately describes the general characteristics of the line to be routed.
5. Develop a set of impact variables to be used in quantifying the impact of routing a given line through the area of concern.
6. Develop a set of weights to be associated with each impact variable in order to effect a given routing strategy.
7. Assess the impact of orthogonal moves between cells and quantify.
8. Apply search algorithm to identify least cost path from beginning cell to ending cell.

II. BASED ON THE PROGRAM CORRIDOR (PART OF THE PACKAGE TRANSTHETICS)

As applied to the transmission corridor selection problem, Corridor assumes that the suitability of a site for the location of a transmission facility can be represented by a suitability function:

$$S_{ij} = f(X_i, Y_j)$$

where

S_{ij} = suitability of site j for transmission facility configuration i

X_i = the set of variables which describe the physical characteristics of facility i

Y_j = the set of inventory variables given in Table 2 which describes the natural and cultural conditions and activities prevailing on site j

f = the impact function which relates X and Y .

By proper definition of f , a variety of strategies can be effected. For instance, if the categories of Pedology, Hydrology and Vegetation are weighted more heavily than the other inventory categories, then the route identified would be one that minimized damage to natural systems. Similarly, if the categories of other transportation/communication and Proposed Transportation/Communication were weighted most heavily then the route that maximized ROW sharing could be identified. Once a strategy has been defined and the suitability index S_{ij} determined for each cell, the optimum route is determined using a less formalized optimization algorithm than that used by Power. In effect, for each feasible route as defined by the planning team the optimum route for each major cell category is determined. Mathematically we have the following:

Let

$$S_k = \sum_j S(X_i, Y_j(L)) \quad k = 1 \dots N$$

Then find $\hat{k}$, denoted by k , which

$$\max_{k \in N} S_k$$

Where

S_k = the suitability index for alternative route k

$\hat{K}(L)$ = the optimal alternative for inventory variable L

L = inventory variable defining routing strategy

Once $\hat{K}(L)$ is known for each L defining the strategy then a composite overlay map is created in which $\hat{K}$ is displayed for each L considered. Typically such composites take the form of a series of links which are easily identifiable and quantifiable. The final step is the detailed evaluation of each link with emphasis placed on construction costs and ROW costs.

APPENDIX B: CAPACITY EXPANSION PLANNING

I. LINEAR PROGRAMMING

A. Garver's Linear Programming Method

$$\min \sum_k P_k G_k$$

s.t.

$$P_i = \sum_k P_k$$

$k = \text{all paths incident on bus } i$

P_k = flow on path k

P_i = net injected power into bus i

G_k = guide number of path k

The actual solution mechanism employed by Garver is based on a linear flow estimation scheme which involves the following procedure:

1. Select links to form a tree connecting all busses.
2. Define all flows on the nontree overload paths to be zero, and set the nontree circuit flows to either 0 or C_k .
3. Determine the flows in the tree links by beginning at an end branch and working down the tree.
4. Compute bus-guide potentials by defining one bus to have zero potential and forcing the following relation for all other tree links:

$$\delta_i - \delta_j = G_k \quad k = \text{tree link}$$

5. Evaluate the flow settings of all nontree links and set flow equal to zero if $\delta_i - \delta_j \geq G_k$ and equal to C_k if $\delta_i - \delta_j \leq G_k$.
6. Because the initial flow pattern will not be optimal i.e., there are paths through which flow could move that would produce a smaller value of cost, a correction to the pattern is required which is effected by identifying one link where the flow determined in step 5 disagrees with the flow assigned to the link in step 2. The flow in this link and all other tree links in the loop containing this link is increased until it zeros a link flow or causes the link to carry its capacity flow.

For the most part, the above steps were extracted from Garver's paper to insure accuracy of the presentation. Clearly, to execute the above steps requires little mathematical analysis based on detailed system models. Rather, the bulk of the method utilizes computer logic combined with logic directing movement through the network using the topological characteristics that must be part of the input.

B. Kaltenbach et. al. Approach

Like Garver's method the approach proposed by Kaltenbach et. al. is also based on a linear model of the network, i.e.,

Linear Power-Flow Model

$$\sum_{j \in K(i)} \gamma_{ij} (\theta_i - \theta_j) = I_i \quad i = 1 \dots N - 1$$

$K(i)$ = set of all busses incident on bus i

γ_{ij} = capacity of branch ij

θ_i = voltage phase angle at bus i

I_i = real power injection at bus i

Transmission capacity of link $L(k)$

$$\gamma(k) = \sum_{ij \in L(k)} \frac{V_{ij}^2 X_{ij}}{Z_{ij}^2}$$

Line-Flow Model

$$T_{ij} = \delta_{ij} (\theta_i - \theta_j) \\ = \delta_{ij} \psi_{ij}$$

To consider the possibility of having parallel lines in a given link let $T_{ij}(k)$ denote line ij in link k and let $S(k)$ denote the set of all lines in link k . Then

$$T_{ij}(k) = \gamma_{ij}(k) \psi_{ij}(k) \quad ij \in S(k)$$

describes the flows in all lines constituting link k . If each line has a positive maximum angle denoted by $\bar{\psi}_{ij}(k)$ the maximum angular difference across link k must satisfy the following:

$$|\psi(k)| \leq \min_{ij} \bar{\psi}_{ij}(k) \quad ij \in S(k)$$

For each link in the network, $\bar{\psi}_{ij}(k)$ is determined through contingency testing where for each link $|\psi(k)|$ is in effect set equal to the largest of the smallest line angular differences encountered during the testing for which no overloads occurred. In short, $|\psi(k)|$ is simply a measure of the largest permissible flow through a link that can occur without overloading any individual lines.

With the above system description the capacity expansion planning problem is formulated as follows:

$$\min \Delta c = \sum_{k=1} c_k \Delta \gamma(k)$$

s.t.

$$-|\psi(k)| \leq \psi^*(k) + \sum_{i=1} \frac{\partial \phi_k}{\partial \gamma(i)} \Delta \gamma(i) \leq |\psi(k)|$$

$\psi^*(k)$ = the largest angle across link k encountered during testing

$\frac{\partial \phi_k}{\partial \gamma(i)}$ = sensitivity of the angular difference across link k to changes in capacity of link i

The differences between this approach and Garver's method are quite extensive. This method requires much more detailed system model and associated data; it requires contingency testing; and finally it requires solving a linear programming problem.

II. NONLINEAR PROGRAMMING METHOD (FISCHL)

Fischl in his attempt to extend techniques in circuit theory to power systems formulated the capacity expansion problem as follows:

$$\min_B C(B) = \sum_{\ell=1}^L \frac{1}{2} W_{\ell} (P_{\ell} - P_{\ell}^d)^2$$

s.t.

$$P_i = \sum_{j=1, j \neq i}^N B_{ij} (\delta_i - \delta_j)$$

$$B_{\ell}^m \leq B_{\ell} \leq B_{\ell}^M$$

where

W_{ℓ} = non-negative weighting function

L = number of lines

P_{ℓ} = real power-flow in line

P_i = the net injected real power into bus i

B_{ij} = susceptance of line connecting busses i and j

δ_i = voltage phase angle at bus i

N = number of busses

B_{ℓ} = B_{ij} i.e., line connects busses i and j

$B_{\ell}^m | B_{\ell}^M$ = minimum and maximum line susceptances of line

B = L vector of line susceptances

The key to Fischl's proposed method is the ability to determine the necessary sensitivities using Tellegen's theorem. It can be shown that the gradient of C w.r.t. B is given by

$$\nabla_B C = \begin{bmatrix} \frac{\partial C}{\partial B_1} \\ \vdots \\ \frac{\partial C}{\partial B_L} \end{bmatrix} = \begin{bmatrix} \delta_1 \hat{\delta}_1 + \frac{\partial C}{\partial P_1} \\ \vdots \\ \delta_L \left(\hat{\delta}_L + \frac{\partial C}{\partial P_L} \right) \end{bmatrix}$$

where $\hat{\delta}_i$ are the voltage angles at the busses of the so-called adjoint network which is a network whose performance equations are given by

$$\hat{P}_{ij} = B_{ij} \hat{\delta}_{ij} + B_{ij} (P_{ij} - P_{ij}^d) W_{ij}$$

Interpreted properly, this equation describes the adjoint network which is identical to the actual network except the bus injections are the gradients of the cost function w.r.t. the injected power at the bus in question. Tellegen's theorem which is the basis for the above result states:

$$\sum_{\lambda=1}^L \left[\Delta \delta_{\lambda} \hat{P}_{\lambda} - \Delta P_{\lambda} \hat{\delta}_{\lambda} \right] + \sum_{i=1}^N \left[\Delta \delta_i \hat{P}_i - \Delta P_i \hat{\delta}_i \right] = 0$$

Actually, the above equation is a variation of Tellegen's theorem developed in its original form by Director and extended by Fischl to power systems.

Comparing this technique to those already discussed, one must conclude it represents a major break in approach, and, in fact, has been employed by the industry in developing rather effective analysis tools, especially in the area of contingency checking. The data requirements for this method are no greater than for a standard power-flow, however, the computational effort is greater because of the need to solve two networks--the original and the adjoint. Finally, it should be noted the Puntel et. al. further developed the method by Fischl to produce a commercial grade code for expansion planning.

III. INTEGER PROGRAMMING

Since the capacity expansion problem is really discrete, Lee et. al. formulated it as an integer programming problem, i.e., they developed for each corridor optimal cost curves which consider the discrete nature of line capacities using an approach called M convolution:

Let the capacity curves be denoted as follows

$$\text{Cost: } C_i(x_i) \quad x_i = 0, d \dots n_i d$$

$$\text{ROW: } r_i(x_i) \quad x_i = 0, d \dots n_i d$$

d = capacity increment in MWs

$n_i d$ = maximum capacity of line i

The optimal cost-capacity curve is given by

$$C_T(x_T) = C_1(x_1) * C_2(x_2) * \dots * C_m(x_m)$$

where

$$C_{12}(x_{12}) = C_1(x_1) * C_2(x_2)$$

$$= \min_v C_{12}(x_{12} - v, v) [C_1(x_{12} - v) + C_2(v)]$$

$$v = 0, d \dots nd$$

and

$$L_{12}(x_1, x_2) = 0 \text{ if } r_1(x_1) + r_2(x_2) > r_T \\ = 1 \text{ otherwise}$$

Given the optimal cost-capacity curves the integer optimization problem becomes:

$$\min Z = \sum_{i=1}^m \sum_{j=1}^n C_{ij} x_{ij}$$

s.t.

$$\sum_{j=1}^n x_{ij} \leq 1 \quad i = 1 \dots m$$

$$\sum_{i=1}^m \sum_{j=1}^n A_{ijk} x_{ij} \geq b_k \quad k = 1 \dots p$$

$$x_{ij} = 0 \text{ or } 1$$

m = no. of ROWs considered

n_i = no. of discrete capacity increments in ROW i

p = no. of overloads

C_{ij} = cost associated with the j^{th} increment in the i^{th} ROW

$$A_{ijk} = \left(\frac{\partial \psi_k}{\partial y_{ij}} \right) \Delta y_{ij}$$

Δy_{ij} = admittance associated with j^{th} increment of i^{th} ROW

$b_k = \Delta \bar{\psi}_k$, the amount of the k^{th} overload

$x_{ij} = 1$ if line addition equal to j^{th} increment in i^{th} ROW is made
0 otherwise.

APPENDIX C: COHERENCY-BASED DYNAMIC EQUIVALENCING

I. MATHEMATICAL MODELS FOR COHERENCY IDENTIFICATION

A. Dynamical Equations:

$$M_i \frac{d\Delta\omega_i}{dt} = \Delta PM_i - \Delta PG - D_i \Delta\omega_i \quad i = 1 \dots G$$

$$\frac{d\Delta\delta_i}{dt} = 2\pi f_o \Delta\omega_i \quad i = 1 \dots G$$

B. Network Equations:

$$\Delta PG_i = \frac{\partial PG_i}{\partial \delta_1} \Delta\delta_1 + \dots + \frac{\partial PG_i}{\partial \theta_1} \Delta\theta_1 + \dots \quad i = 1 \dots G$$

$$\Delta PL = \frac{\partial PL}{\partial \delta_1} \Delta\delta_1 + \dots + \frac{\partial PL}{\partial \theta_1} \Delta\theta_1 + \dots \quad i = 1 \dots L$$

The simultaneous solution of the above equations produces $\delta_i(t)$ vs time plots from which

coherent groups can be identified. Fault type disturbances are simulated by appropriate changes in $\Delta PM - \Delta PG$ and load rejection is simulated using ΔPL .

II. MATHEMATICAL MODELS FOR COHERENT GENERATOR AND LOAD BUS REDUCTIONS:

A. Generator Bus Reductions:

Assume there are G generators in a coherent group for which it is desired to obtain a one bus equivalent, then:

1. The voltage of the equivalent is

$$|V_t| = \frac{1}{G} \sum_{k=1}^G |V_k| \quad \theta_t = \frac{1}{G} \sum_{k=1}^G \theta_k$$

2. The b_t^{th} and t_b^{th} terms of the reduced admittance matrix, where b is a particular boundary bus, is

$$Y_{bt} = \sum_{k=1}^G \frac{V_k}{V_t} Y_{bk}$$

$$Y_{tb} = \sum_{k=1}^G \frac{V_k^*}{V_t^*} Y_{kb}$$

3. The t_t^{th} term of the bus admittance matrix is

$$Y_{tt} = \sum_{k=1}^G \sum_{c=1}^G \frac{V_k}{V_t} Y_{ck} \frac{V_c^*}{V_t^*}$$

4. The generation and load at the equivalent bus are

$$S_G = \sum_{k=1}^G S_{GK}$$

3.

$$S_L = \sum_{k=1}^G S_{LK}$$

B. Load Bus Reductions:

1. Using the REI Method

Define a common bus to which all the busses to be eliminated can be connected, call it the G bus, where $V_G = 0$. Further assume that the flow into the G bus emanates from a bus denoted by R which is connected to G through admittance Y_R , then

$$Y_R = I_R \left(V_G - V_R \right)$$

where

$$V_R = S_R | I_R^*$$

and

$$I_R = \sum_{i=1}^n I_i \quad \text{Sum of injected currents into busses being eliminated.}$$

$$S_R = \sum_{j=1}^n S_j \quad \text{Sum of injected powers into busses being eliminated.}$$

The network of admittances connecting the G bus to all the busses to be eliminated can take many forms, but the simplest is the star network where

$$Y_j = I_j / (V_j - V_G)$$

$$I_j = I_j^* / V_j^* \quad S_j \text{ and } V_j \text{ are known from base case power-flow}$$

Having a passive network representation of the nonlinear power injections any one of the variations of the Ward-Hale method can be used to actually eliminate the busses.

2. Using the Current Sink Method

All impedance loads are simply included in the admittance matrix for reduction purposes, and all current and power loads are converted into so-called current sinks and thus appear in the current vector, i.e.,

$$\begin{bmatrix} I_1 \\ 0 \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} \\ Y_{21} & Y_{22} \end{bmatrix} \begin{bmatrix} V_1 \\ V_2 \end{bmatrix} + \begin{bmatrix} 0 \\ I_I \end{bmatrix} \quad \begin{bmatrix} 0 \\ I_S \end{bmatrix}$$

where I_I is the current sink variable for current loads and I_S is the current sink variable for power loads converted into currents. Applying Gaussian Elimination on the above, it can be reduced to

$$I_1 = Y'_{11} V_1 + I'_I + I'_S$$

where

$$Y'_{11} = Y_{11} - Y_{12} \begin{bmatrix} Y_{22}^{-1} \end{bmatrix} \begin{bmatrix} Y_{21} \end{bmatrix}$$

and

$$I'_I = -Y_{12} Y_{22}^{-1} I_I$$

$$I'_S = -Y_{12} Y_{22}^{-1} I_S$$

Since I'_I and I'_S are the equivalent current sinks on the retained busses, they can be reconverted back to a constant power form as the voltage of the bus from which the currents flow is assumed known and equal to its base case value. Finally the constant impedance portion of the equivalent load is obtained by extracting from the admittance

matrix of the equivalent system the appropriate shunt admittance and calculating its power equivalent.

III. AGGREGATION

A. Rotor Dynamics

On the assumption that coherent machines have the same speed deviations, the rotor dynamics of the equivalent machine is

$$\left(\sum_j 2H_j \right) \frac{d\Delta\omega}{dt} = \sum_j P_{Mj} - \sum_j P_{Gj} - \left(\sum_j D_j \right) \omega$$

where obviously the equivalent inertia and damping constant are the sum of the individual inertia and damping constants.

B. Turbine-Governor Dynamics

Ignoring nonlinearities and summing the Turbine-Governor transfer functions to create what is called the aggregate transfer function, the parameters of an equivalent, simplified transfer function can be identified by comparing the frequency response of the aggregate with that of the equivalent. If large discrepancies occur, the equivalent model parameters are appropriately altered until the frequency response are sufficiently close. Specifically if $G(S)$ represents the Governor-Turbine transfer function for unit j , then

$$G_A(S) = \sum_j G_j(S)$$

is the aggregate. Further if $G^*(S)$ is the equivalent transfer function where

$$G^*(S) = K \frac{1 + ST_2}{(1 + ST_1)(1 + ST_3)} \cdot \frac{1}{(1 + ST_4)}$$

then the parameters T_1, T_2, T_3 , would be calculated by the use of an appropriate iterative algorithm. K is determined by forcing the error between the aggregate and its equivalent to be zero for $\omega = 0$ where the error function is

$$\sum_i \frac{|G_A(j\omega_i) - G^*(j\omega_i)|^2}{|G_A(j\omega_i)|^2}$$

C. Synchronous Machine

Since the real power output of a synchronous machine is given by

$$P_G = V_q i_q + V_d i_d$$

then the power produced by a coherent group is

$$P_G = \sum_j (V_{qj} i_{qj} + V_{dj} i_{dj})$$

However under the assumption that the units are coherent

$$P_G = V_Q \sum i_{qj} + V_D \sum i_{dj}$$

$$= V_Q i_Q + V_D i_D$$

where

$$\begin{bmatrix} i_D \\ i_Q \end{bmatrix} = \begin{bmatrix} Y_{DD} & Y_{DQ} \\ Y_{QD} & Y_{QQ} \end{bmatrix} \begin{bmatrix} V_D \\ V_Q \end{bmatrix} + \begin{bmatrix} Y_{DF} \\ Y_{QF} \end{bmatrix} e_{FD}$$

The admittances depend on the parameters of the individual machines as well as the position chosen for the two axis D and Q. In fact, by adjusting the axis positions Y_{DD} , Y_{QQ} , and Y_{QF} can be reduced to zero over the frequency range of interest. The resulting aggregate model can now be used to adjust the parameters of an equivalent model where

$$\begin{bmatrix} i_D^*(s) \\ i_Q^*(s) \end{bmatrix} = \begin{bmatrix} 0 & Y_{DQ}(s) \\ Y_{QD}(s) & 0 \end{bmatrix} \begin{bmatrix} V_D \\ V_Q \end{bmatrix} + \begin{bmatrix} Y_{DF} \\ 0 \end{bmatrix} e_{DF}$$

describes the equivalent i.e., the equivalent model parameters are adjusted until

$$Y_{DQ}^*(s) \cong Y_{DQ}(s)$$

$$Y_{QD}^*(s) \cong Y_{QD}(s)$$

$$Y_{DF}^*(s) \cong Y_{DF}(s)$$

In every case above, the admittances are operational admittances, and thus to adjust the equivalent model parameters to achieve the above equalities requires making both the magnitude and angles of the admittances identical.

D. Excitation Systems

Since the approach used to determine the equivalent excitation system is similar to the approach used to obtain the equivalent turbine generator model the reader is referred to the references for details.

APPENDIX D: ANALYTICAL DESIGN FORMULATIONS

I. GENERAL DESIGN PROBLEM

$$\min_x F(x) = \sum_i f_i(t, x_t, y_t, W_t)$$

subject to

$$h(t, x_t, z_t, v_t) = 0$$

$$g(t, x_t, z_t, v_t) \leq 0$$

$$y_{t+1} = y_t + x_t$$

$$y_t^m \leq y_t \leq y_t^M$$

$$x_t^m \leq x_t \leq x_t^M$$

where

f_i = cost functions to be optimized

h = equality relations between dependent variable Y and independent variable x

g = inequality relations between dependent variable Y and independent variable x

y_t = dependent state

x_t = independent decision variables

W_t = uncertainty in cost function

V_t = Uncertainty in relationship between x_t and Y_t

II. NOMINAL DESIGN PROBLEM

Let $V_t = W_t = 0$. then problem reduces to

$$\min_{x_t} F = \sum_i f_i(x_t, y_t)$$

s.t.

$$h(x_t, y_t) = 0$$

$$g(x_t, y_t) \leq 0$$

$$y_t^m \leq y_t \leq y_t^M$$

$$x_t^m \leq x_t \leq x_t^M$$

III. LP TOLERANCE DESIGN PROBLEM

A. Probabilistic Programming

$$\min(C_x^t + E(d^t y))$$

s.t.

$$Ax + Ty = b$$

$$x, y > 0$$

Note that this is the two stage restatement of the LP problem with uncertainty in which b is assumed to be random.

B. Chance Constrained Formulation

$$\min_x C^T x$$

s.t.

$$\Pr \left[\sum_{j=1}^n a_{ij} x_j \geq b_i \right] \geq \gamma_i \text{ for } \gamma_i, x \geq 0$$

In this case a solution x is sought for which the probability that the weighted sum of the decision variables is greater than or equal to b_i . Many problems can be cast in this way where the solution is obtained by transforming the problem into a linear deterministic equivalent. However, there are two major drawbacks normally associated with probabilistic programming: First, the statistics

of the model parameters may not be a priori known, and second, conservative results are obtained since the method does not provide information about the range of variations in x .

C. Flexible Programming

$$\min \sum_{i=1}^n (C_i x_i + \alpha_i \Delta x_{i-} + \beta_i \Delta x_{i+})$$

s.t.

$$A x = b$$

$$x \geq 0$$

$$x + \Delta x_{+} + \Delta x_{-} \in X^*$$

Δx_{+} and Δx_{-} are the deviations in the solution and α_i and β_i are costs of such deviations. X^* is the permanently feasible set and as such is comprised of all values of x that result from random changes in the elements of A and b .

Unfortunately flexible programming is still very much unexplored where the main thrusts have been based on the following assumptions: 1) that both the best estimates of A and b as well as their interval variation are known 2) that the dependence between the matrix elements are known, and 3) that the cost coefficients α and β are known. Fischl states that to date the most significant spin off from flexible programming research is the ability to define the permanently feasible set x^* in terms of the parameter variations under certain conditions.

IV. NONLINEAR PROGRAMMING

A. Worst-case Tolerancing With Centering

$$\min F(\Delta x) = \sum_{i=1}^n c_i (\Delta x_i)$$

s.t.

$$G_j^m \leq g_j(x, \Delta x) \leq G_j^M \quad j = 1 \dots m$$

$$(1 - \Delta x_i) x_i^0 \leq x_i \leq (1 + \Delta x_i) x_i^0$$

x_i^0 = nominal value of independent quantity

Δx_i = tolerance of variable x_i

The concept of centering simply means that changes in the nominal values of the independent quantities will take place in the optimization. Since the costs tend to be inversely proportional to the tolerances, low cost implies large tolerances. Thus, the problem boils down to finding the largest polytope that will fit inside the constraint region.

B. Statistical Tolerancing With Centering

$$\min_{\Delta x_i} F(\Delta x) = \sum_{i=1}^n C_i (\Delta x_i)$$

s.t.

$$P_r \left[G_j^m \leq g_j(x, \Delta x) \leq G_j^M \right] \geq d$$

d represents the probability that the constraints are satisfied. Unfortunately, to date, no general solution procedures exist to solve the above problem. However, various approximate methods have been proposed to circumvent the usual problem of not knowing the probability distribution describing the variations in g due to changes in x .

V. MULTI-LEVEL OPTIMIZATION

$$\min_x F(x, u) = \sum_{k=1}^N F^k(x^k, y^k, u^k)$$

s.t.

$$h^k(x^k, y^k, u^k) = 0$$

$$g^k(x^k, y^k, u^k) \geq 0$$

$k = 1 \dots N$

$$u^k = d^k(x^j, y^j)$$

$j \neq k$

$k = k^{\text{th}}$ subsystem

u^k = model coordination variable which decompose h and g into subsystem quantities h^k, g^k

or

$$\min_x F(x, u) = \sum_{k=1}^N \left[F^k + r^k u^k - d^k \right]$$

s.t.

$$h^k = 0 \quad k = 1 \dots N$$

$$g^k \geq 0$$

r^k = goal coordination variable: can be considered either as a lagrange multiplier or a penalty factor.

Since the cost function F is clearly separable as are the functional relations, the above optimization problem involves solving the individual subsystem problems. As one may expect, the condition of decomposability is crucial for multi-level design but at this time there are no general approaches available for determining whether a given system can be decomposed--which is a definite weakness of the method.

VI. VECTOR OPTIMIZATION

The general vector optimization problem can be stated as follows:

$$\max z(x) = [z_1(x), z_2(x) \dots z_p(x)]$$

s.t.

$$g_i(x) \leq 0 \quad i = 1 \dots m$$

$$x_i \geq 0 \quad i = 1 \dots n$$

where

$z_i(x)$ = i^{th} objective in the vector z .

x = decision variable vector

$g_i(x)$ = i^{th} inequality constraints

The solution of the above is a set of noninferior values of x where a noninferior value of x , denoted by x' must be in the feasible set X and satisfy the following:

$$z_r(x') > z_r(x)$$

for some $r = 1 \dots p$ and

$$z_k(x') \geq z_k(x)$$

for all $k \neq r$. To generate the set $x' \in X$ the following representative methods can be used.

A. Weighting Method

Kuhn and Tucker proved that any vector x which satisfies the noninferior condition is a solution to the following scalar optimization problem

$$\max \sum_k w_k z_k(x)$$

s.t.

$$g_i(x) = 0 \quad i = 1 \dots m$$

$$x_i \geq 0$$

The necessary conditions that x must satisfy to maximize the weighted sum of objectives are

$$\lambda_i g_i(x) = 0 \quad i = 1 \dots m$$

$$\sum_{k=1}^p w_k \nabla z_k(x) - \sum_{i=1}^m \lambda_i \nabla g_i(x) = 0$$

where λ_i is the familiar dual variable. Thus what Kuhn Tucker implied was simply that for $z_k(x)$ concave and x convex, that all of the noninferior values of x could be generated by solving the above scalar optimization problem for various weights $w_k \geq 0$ $k_1 = 1 \dots p$.

B. Constraint Method

By expanding the necessary condition equations above as follows

$$g_i(x) \geq 0$$

$$w_r \nabla z_r(x) + \sum_{k=1}^p w_k \nabla z_k(x) - \sum_{i=1}^m \lambda_i \nabla g_i(x) = 0$$

and then dividing the last equation by w_r we get

$$\nabla z_r(x) + \sum_{k \neq r} w'_k \nabla z_k(x) - \sum_i \lambda'_i \nabla g_i(x) = 0$$

Realizing that the second term like the last term appears in the form of a constraint, it suggests that an alternate formulation of the vector optimization problem would be

$$\max_x z_r(x)$$

s.t.

$$g_i(x) \geq 0 \quad i = 1 \dots m$$

$$z_k(x) \geq L_k \quad k \neq r$$

Thus by parametrically varying the lower bound L_k for all $k \neq r$, the noninferior solutions x can be generated.

C. Surrogate Worth Trade-Off Method

By definition, for every noninferior solution for a given set of lower bounds L_k , $k \neq r$

$$\nabla z_r(x) = - \sum_k w'_k \nabla z_k(x) + \sum_i \lambda'_i \nabla g_i(x)$$

thus

$$w'_k = - \frac{\partial z_r(x)}{\partial z_k(x)}$$

at the solution point x where the value of the objective z_k is $z_k(x)$. As such w'_k established the trade-off between the objectives as a function of the lower bound on objective k or as a function $z_k(x)$ itself. In terms of planning, it, in effect, provides the planner with information to determine how to weight the objectives but still remain with perhaps subjective lower bounds on each objective.

APPENDIX E: RELIABILITY ANALYSIS

I. CONDITIONAL PROBABILITY APPROACH

A. The fundamental concept on which this approach is based is

$$P(A \cap B) = P(A) P(B/A)$$

If the events A and B are independent, then

$$P(A \cap B) = P(A) P(B)$$

Knowing $P(A \cap B)$ one can determine $P(B)$ as follows

$$P(B) = \sum_{i=1}^I P(B/A_i) P(A_i)$$

In the simple case where A can assume only two values A_x and A_y , then

$$P(B) = P(B/A_x) P(A_x) + P(B/A_y) P(A_y)$$

Viewing a power system in a very abstract fashion, i.e., assuming it is composed of a series combination of generation, transmission, and load, and assuming that

P_{Lj} = probability that the load exceeds the transmission capacity when in capacity state j

P_{Gj} = probability load exceeds generation capacity when in capacity state j

A_1 = availability of adequate transmission capacity

then the probability of failure to serve the load is

$$Q_s(\text{system failure}) = A_1 \left(P_{L1} + P_{G1} \right) + \bar{A}_1 (1) = A_1 \left(P_{L1} + P_{G1} \right) + \bar{A}_1$$

In general,

$$\text{Prob of failure} = \sum_j P(B_j) (P_{Gj} + P_{Lj} P_{Gj})$$

where

B_j = transmission network capacity state j

$P(B_j)$ = probability of existence of state B_j

P_{Gj} = probability of insufficient generation capacity given transmission network is in state j

P_{Lj} = probability load will exceed transmission capacity as network resides in state j

In addition to the probability of failure, the frequency at which failure states are encountered can also be determined. Frequency of encountering a state is simply the product of being in the state times the departure rate out of the state. Letting $F(B_j)$ represent the frequency of encountering the transmission network state j , then

$$\text{freq of failure} = \sum_j F(B_j) (P_{Gj} + P_{Lj} P_{Gj})$$

As stated in the literature the above expression ignores the rates of departure associated with both the generator and load. Including them evidently complicates the procedure greatly.

Because Marks in his paper includes much more detailed generation and load models than have been considered here, and since Marks has basically applied the conditional probability approach, further modeling details will be discussed in a subsequent section.

B. Reliability Analysis Using High Speed Contingency Analysis

Marks in his recent IEEE paper described the approach taken by his company to assess the reliability of their system. In effect, Marks is using a high speed power-flow program to assess the effects of the various failure modes considered. He defines a service failure mode (SFM) as

"any system state which results in either complete or partial loss of load at one or more busses due to a break in continuity, unacceptable voltages, or capacity limitations." Specifically

$$P_{SFM} = \bar{A}_x \cdot \prod_{\substack{i=1 \\ i \neq x}}^n A_i$$

$$\mu_{SFM} = \mu_x + \sum_{\substack{i=1 \\ i \neq x}}^n \lambda_i$$

$$f_{SFM} = P_{SFM} \mu_{SFM}$$

$$\lambda_{SFM} = f_{SFM} / (1 - P_{SFM})$$

where

P_{SFM} = Probability of encountering a SFM

μ_{SFM} = departure rate from SFM

f_{SFM} = frequency of encountering SFM

λ_{SFM} = rate of entry into SFM

$\bar{A}_x$ = component unavailability

A_i = component availability

μ_x = component repair rate

λ_i = component failure rate

n = total number of components

To improve the efficiency of computing the above quantities cumulative values of the availabilities and failure rates are calculated and used in determining P , μ , f , and λ for a given failure mode, i.e.

$$A_\Omega = \prod_i A_i$$

$$\lambda_\Omega = \sum_i \lambda_i$$

Then, for a given failure

$$P_{SFM} = \frac{\bar{A}_x A_\Omega}{A_x}$$

$$\mu_{SFM} = \mu_x + \lambda_\Omega - \lambda_x$$

$$f_{SFM} = P_{SFM} \mu_{SFM}$$

$$\lambda_{SFM} = f_{SFM} / (1 - P_{SFM})$$

Although the generating unit failure characteristics are treated like any other system component, the load model is obtained by determining from historical hourly load data the transition rates between two load-level dependent load states: unserviceable loads and serviceable loads. The

load level separating the loads into these two states is called the critical load and is dependent on the SFMs. For a given SFM the critical load levels can be determined and the following parameters calculated:

$$\mu_{LL} = \text{TPH} \left(\frac{N_T}{N_H} \right)$$

$$\lambda_{LL} = N_T / \left(1 - N_H / \text{TPH} \right)$$

$$P_{LL} = \lambda_{LL} / (\lambda_{LL} + \mu_{LL})$$

LL = a given load level in MWs

λ_{LL} = entry rate into higher load state

μ_{LL} = departure rate into lower load states than LL

TPH = hours of historical data

N_T = number of times load exceeds LL

N_H = number of hours load exceeds given load level

P_{LL} = probability of load exceeding LL

UE_{LL} = unserved energy due to load units in excess of critical load

The conditional probability calculations to determine the probability of a system failure are performed using the following

$$P_{SFM}^* = P_{SFM} P_{cL}$$

$$\mu_{SFM}^* = \mu_{SFM} + \mu_{cL}$$

$$f_{SFM}^* = P_{SFM}^* \mu_{SFM}^*$$

where

P_{cL} = probability load exceeds a critical load given a failure mode exists

μ_{SFM} = frequency of encountering failure state

Since the expected duration d_{SFM}^* of service failures is often used as a measure of service reliability, it can easily be determined from

$$d_{SFM}^* = \frac{\text{TPH}}{\mu_{SFM}^*}$$

Utilizing the above basic approach, definitions, and concepts Marks can calculate probabilities, expected averages, and service reliability indices.

C. Graph Theoretic Approach to Reliability Analysis

Baleriaux et al in a Cigre paper proposed a conceptually interesting method for system reliability analysis using a graph theoretic representation of the network, i.e., let

V_m = integer state of element m:

$V_m = 1$ if element is in and

$V_m = 0$ if element is out

P_m = availability of element m

x_i = integer state of system

$\bar{x}$ = upper limiting state of system

$\underline{x}$ = lower limiting state of system

then the probability of the system being in state x_i , denoted by $f(x_i)$, is

$$f(x_i) = \prod_{m=1}^E f(V_m)$$

where

$$f(V_m) = P_m \text{ if } V_m = 1$$

and

$$f(V_m) = q_m \text{ if } V_m = 0$$

Given the above, the probability of loss-of-load, LOLP, is

$$\text{LOLP} = \sum_{x_i \in B} f(x_i)$$

B = set of unacceptable states

The expected value of the unserved demand, $\epsilon(\text{DNS})$, is

$$\epsilon(\text{DNS}) = \sum_{x_i \in B} f(x_i) (L - g_i)$$

L = system load

g_i = maximum flow through network when in state x_i

For computational reasons Baleriaux recognized the need to avoid evaluating the above sums on a state by state basis, and, therefore, devised a procedure for identifying the critical system capacity state for which higher states are acceptable and lower states are unacceptable. Further, all the unacceptable states are associated with nonoverlapping subsets, B_j , i.e.,

$$\begin{aligned} \text{LOLP} &= \sum_{x_i \in B} f(x_i) \\ &= \sum_{B_j} f(B_j) \end{aligned}$$

By further decomposing the sets B_j into sets $\hat{B}_n$

where all states $x_i \in B_n$ have the same minimal cut, the following convenient expression for $\epsilon(\text{DNS})$ can be obtained

$$\epsilon(\text{DNS}) = L(\text{LOLP}) - \sum_{\hat{B}_n} \sum_{m \in M} \frac{\bar{c}_m f(\hat{B}_n)}{f(V_m(\hat{B}_n))}$$

M = the minimal-cut elements in set $\hat{B}_n$

$\bar{c}_m$ = expected value of the capacity of the minimum-cut element

$f(V_m(\hat{B}_n))$ = probability that the minimum-cut element resides in a state $V_m \in \hat{B}_n$

Clearly, since the network is described only in terms of the element capacities, the indices of performance are devoid of information about the suitability of the network in terms of voltage related behavior. Furthermore, because of the abstractness of the model of the network employed, some argue that the flow distributions through the network are unrealistic. In this regard, the procedure put forth by Marks is superior. However, if viewed purely as a technique to evaluate the network structure this approach may have some use in regional planning.

D. Graph Theoretic Multi-Area Analysis

Pang and Wood extended the graph theoretic approach to the multi-area problem, and, as such, produced a tool that could find a great deal of use in regional transmission planning.

Let the state of a multi-area system be denoted by

$$x_i = (r_1, r_2, \dots, r_A, V_1, V_2, \dots, V_I)$$

where

r_i = integer reserve margin state of area i

V_i = integer capacity state of inter-connection i

Through a search procedure the system states are classified as follows:

A = subset of acceptable states

$\hat{B}_n$ = subset of states that are interconnection unacceptable

B_j = subset of states that are reserve margin unacceptable

The probability that the states reside in B_n is given by

$$f(\hat{B}_n) = \pi f_k(r_k \leq r_{ko}) \pi f_j(r_j \geq r_{jo}) \cdot \pi f_{m \in M}(V_m \leq V_{mo}) \pi f_{m \in M}(V_m \geq V_{mo})$$

where

$\pi f_k(r_k \leq r_{ko})$ = probability that the reserve margin states of all deficient areas is less than the unacceptable state r_{ko} .

$\pi f_j(r_j \geq r_{jo})$ = probability that the reserve margin state of all self-sufficient areas is greater than the acceptable state r_{jo} .

$\pi f_{m \in M}(V_m \leq V_{mo})$ = probability that the capacity state of all minimum-cut inter-connections are less than the unacceptable state V_{mo} .

$\pi f_{m \in M}(V_m \geq V_{mo})$ = probability that the capacity state of all non-minimum-cut inter-connections is greater than the acceptable state V_{mo} .

Similarly, the probability that states reside in B_j is given by

$$f(B_j) = \pi f_k(r_k \leq r_{ko}) \pi f_j(r_k \leq r_{jo}) \pi f_m(V_m \geq V_{mo})$$

Finally, the LOLP for area k is

$$\text{LOLP}^k = \sum_n f(\hat{B}_n) + \sum_j f(B_j)$$

and the total system reliability is

$$\text{LOLP} = \sum_k \text{LOLP}^k$$

APPENDICES
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APPENDIX 1

LOAD FLOW SOLUTION METHODS

This appendix contains a brief summary of the most important load flow algorithms.

1.0 GAUSS-SEIDEL Y-MATRIX METHOD

The Gauss-Seidel method utilizes the basic Y-matrix equation (1.1).

$$\underline{I} = [\underline{Y}] \underline{E} \quad (1.1)$$

where: $\underline{I}$ are bus current injections.
 $\underline{E}$ are bus voltages.
 $[\underline{Y}]$ is the bus admittance matrix.

Each individual bus voltage can be expressed in terms of equation (1.2).

$$E_i = \frac{1}{Y_{ii}} (I_i - \sum_{k \neq i} Y_{ik} E_k) \quad (1.2)$$

where i and k are bus indices.

The network solution is obtained by recomputing the bus voltages one by one, and for each new bus voltage computation utilizing the most recently computed values for the other bus voltages. This is referred to as a single sweep, successive-displacement process. At each step the bus current is computed based on the applicable bus specifications. For example, for a load bus the relationship is as given in equation (1.3). Here the values of voltage magnitude and angle are both computed during the previous iteration.

$$I_i = \frac{P_i^{sp} - Q_i^{sp}}{V_i} e^{j\theta_i} \quad (1.3)$$

where superscript sp indicates specified quantity.

After each iteration a check is made to determine if the solution has converged to an acceptable accurate solution. A positive check for convergence is obtained by comparing the specified power injection at each bus with those computed based on the current voltage solution. If the "mismatch" at any bus is greater than a specified mismatch tolerance, the iterative process is continued. Since this check is somewhat time consuming, it is only performed after a preliminary voltage change check has established that the maximum change in a bus voltage from one iteration to the next is less than a specified tolerance; that is, the iterative solution has settled down.

Since the convergence characteristics of the Gauss-Seidel iterative procedures are asymptotic (see Figure 5-1), they can generally be speeded up by multiplying the voltage corrections obtained at each step by acceleration factors.

The computational efficiency of the Gauss-Seidel Y-matrix method derives from the limited number of elements in the summation in equation (1.2). Since there is only one Y_{ik} element for each circuit connected to a bus, the average number of elements is typically about three. This results in very low storage requirements and very few computational steps per bus voltage computation. Since the number of elements in the summation in equation (3.2) does not vary much with system size, the storage requirements are roughly proportional to the number of buses. However, the number of iterations required increases with system size resulting in computer time that is typically a quadratic function of system size.

2.0 Z-MATRIX METHODS

The Z-matrix method is based on equation (2.1) where $[Z]$ is the inverse of the Y-matrix.

$$\underline{E} = [Z] \underline{I} \quad (2.1)$$

With the bus current evaluated as in equation (1.3), a successive-displacement technique can be used also in this case. The major difference between equation (2.1) and equation (1.1) is that in equation (2.1) the voltage at a particular bus is related to the current injection at all other buses in the system. This results in good convergence characteristics as the Z-matrix method typically converges in about ten iterations. On the other hand, the computational requirement for each iteration is great due to the full Z-matrix. Moreover, the Z-matrix method tends to be less efficient computationally than the Gauss-Seidel method for medium and large scale systems, and the storage requirements being proportional to the square of the number of buses would be prohibitive on large-scale systems.

Equation (2.1) can be solved very efficiently and with moderate storage requirements by the use of sparsity coded Gaussian elimination where computations are performed on a factorized Y-matrix rather than on the explicitly inverted Y-matrix. These techniques, however, are implicitly a simultaneous-displacement technique as contrasted to the successive-displacement technique used in the regular Z-matrix method and also in the Y-matrix iterative methods. Unfortunately, the simultaneous-displacement technique does not work well with buses where constant voltage is specified (generator buses), but it works well in many other situations. For example, the technique has proved efficient as the network solution for stability programs where there are only swing buses and load buses and no generator buses.

3.0 NEWTON METHOD

The Newton method is based on equation (3.1) where the deviations at any particular point in time of the real and reactive powers from the specified values is expressed in terms of corresponding changes in the bus voltage quantities.

$$\begin{bmatrix} \underline{\Delta P} \\ \underline{\Delta Q} \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \theta} & \frac{\partial Q}{\partial V} \end{bmatrix} \begin{bmatrix} \underline{\Delta \theta} \\ \underline{\Delta V} \end{bmatrix} \quad (3.1)$$

The system matrix referred to as the Jacobian matrix consists of partial derivatives which have to be recomputed throughout the process. Since ΔP and ΔQ are known, the solution for the voltage changes is obtained by Gaussian elimination. The Newton method typically converges in five to ten iterations and faster when starting from a previously solved case. When efficient sparsity techniques are used, the Newton method is fast and involves only a moderate amount of storage space. For well-programmed algorithms, the computer time per iteration of the Newton method increases approximately linearly with the number of buses in the system. Therefore, it rapidly becomes more efficient than the Gauss-Seidel iterative Y-matrix method as the system increases. Although the storage requirement for the factorized Jacobian matrix is significantly more than for the sparse Y-matrix required in the Gauss-Seidel method, even the largest systems can be solved on a big-size computer. As with computer time, the storage requirement increases about linearly with the number of buses.

4.0 DECOUPLED NEWTON METHOD

Electric power transmission systems, particularly at high voltages where X/R of individual circuits are large, have inherently strong couplings between real power and phase angle and between reactive power and voltage magnitude, and correspondingly very weak couplings between real power and voltage magnitude and reactive power and phase angle. This provides an opportunity to decouple the computational problem into a P θ problem and a QV problem. In terms of equation (3.1), this means that $\partial P/\partial V$ and $\partial Q/\partial \theta$ are rather small, and as a first approximation can be ignored. Equations (4.1) describe one proposed approach to the decoupling problem.

$$\begin{aligned} \underline{\Delta P/V} &= [A] \underline{\Delta \theta} \\ \underline{\Delta Q/V} &= [C] \underline{\Delta V} \end{aligned} \quad (4.1)$$

The equation is based on equation (3.1) with $\partial P/\partial V$ and $\partial Q/\partial \theta$ ignored. In addition, the ΔP and ΔQ terms are normalized by division by the voltage magnitude. This is of major benefit in the QV equation as it makes the problem more linear; that is, the sensitivities in matrix C are less dependent on the exact operating condition.

A full ac solution can be obtained with equation (4.1) by first solving for the phase angles (first equation) which immediately gives results that are accurate within a few degrees. Secondly, the angle results are used in the computation of matrix C and the second equation is

solved for the voltage magnitude. On most systems the results obtained after this first iteration are quite close to the real solution and by repeating the process any desired precision can be obtained within a number of iterations that is not greatly higher than that required for the full Newton solution. The main advantage of the decoupled method over the full Newton method lies in substantially reduced core requirements. Some improvements in solution speed have also been reported.

In a 1974 paper [2], Stott and Alsac proposed the elimination of the state dependent elements of the sensitivities in A and C, arriving at equation (4.2) where B' and B'' now contain only elements derivable from the Y-matrix.

$$\begin{aligned}\Delta P/V &= [B'] \Delta \theta \\ \Delta Q/V &= [B''] \Delta V\end{aligned}\quad (4.2)$$

With this approach B' and B'' need not be changed between iterations, making the computer time required per iteration approximately 20 % [2] of that of a full Newton iteration. Still the process converges to acceptable tolerances in approximately the same number of iterations as the full Newton load flow and is therefore significantly faster at the same time as it requires significantly less computer memory.

5.0 Comparison of Load Flow Methods

5.1 Convergence Characteristics

Figure 5-1 shows typical convergence patterns of the Gauss-Seidel Y-Matrix iterative method, the Z-Matrix method and the Newton Method [4].

FIGURE 5-1

CONVERGENCE CHARACTERISTICS
OF LOAD FLOW ALGORITHMS

5.2 Versatility

Gauss-Seidel Y-Matrix

Advantages: Allows output of meaningful results even for cases that have not converged. Valuable for data problem identification.

Disadvantages: Slow convergence. Basic algorithm does not work for Series capacitors.

Z-Matrix

Advantages: Reliable convergence.

Disadvantages: Excessive storage and time requirement on large systems.

Full Newton

Advantages: Reliable convergence.

Disadvantages: Leaves no meaningful results when it does not converge.

Decoupled Newton

Advantages: Low storage requirements. Meaningful results after one iteration.

Fast Decoupled Newton

Advantages: Fastest ac solution algorithm for moderately accurate results. Suitable for contingency studies.

5.3 Core Requirement

Typical Relative Core Requirements for load flow methods. (N = number of buses):

Methods in order of Increasing Core Req.	Approximate Relationships
Gauss-Seidel (GSY)	Proportional to N
Fast Decoupled Newton (FDN)	0.6 of FN*
Decoupled Newton (DN)	0.6 of FN*
Full Newton (FN)	Proportional to N
Z-Matrix (Z)	N ² real numbers required for storage of Z-Matrix alone

* Derived from Reference 1.

5.4 Computer Time

Typical Relative Computer Time Requirements for single case flat start solution.

<u>Methods in order of Increasing Computer Time</u>	<u>Approximate Relationships</u>
Fast Decoupled Newton (FDN)	0.2 of FN* 0.4 of FN**
Decoupled Newton (DN)	0.8 of FN*
Full Newton (FN)	Proportional to N (30/N of GSY)*
Gauss-Seidel Y-Matrix iteration (GSY)	Proportional to N ²
Z-Matrix (Z)	Proportional to N ² , generally slower than GSY

* Reference 1.

** Reference 5.

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APPENDIX 2

DYNAMIC SIMULATION ALGORITHMS

Time domain simulation programs for digital computers are based on numerical integration of differential equations. In programs designed for large scale power systems, the computations are divided into two parts, which are performed alternately for each timestep. One part is the steady state solution of the network equations (load flow). The second part is a numerical integration of the differential equations representing the dynamics of machines and their controls.

The scope of network algorithms, numerical integration techniques and machine models is immense and cannot be covered in this brief appendix. Rather a summary of the structure of the computations needed to appreciate the limitations in the basic approach is presented along the lines of Reference 1.

Generator Equations

The general form of the generator equations is:

$$\dot{\underline{X}} = [\underline{F}]\underline{X} + [\underline{G}]\underline{I}_G + [\underline{K}]\underline{W} \quad (1)$$

$$\underline{E}_G = [\underline{H}]\underline{X} - [\underline{Z}_G]\underline{I}_G \quad (2)$$

where

$\underline{X}$ are the state variables within the synchronous machine models.

$\underline{I}_G$ are the generator terminal currents.

$\underline{W}$ are output variables of excitations system or turbine-governor models.

$\underline{E}_G$ are generator terminal voltage.

In addition differential and algebraic equations representing excitation systems, turbine governor systems and controls are needed to update the variable $\underline{W}$ needed in equation (1). Although equations (1) and (2) contain all states, voltages and currents needed in the representation of all units, it is important to realize that there is no coupling between generators except through the interconnecting system. Therefore, for a N machine system, one could alternatively have N equation pairs such as 1 and 2, each representing only one generator. Note that equation 2 is a generalized Thevenin equivalent with $[\underline{H}]\underline{X}$ representing the internal voltage behind the internal impedance $[\underline{Z}_G]$. In the simplest case this reduces to the classical "constant voltage behind the transient reactance" model.

It is universal practice to derive the element matrices of $[\underline{F}]$, $[\underline{G}]$, $[\underline{H}]$ and $[\underline{Z}_G]$ by applying the 'Park' transformation [2] to the basic synchronous machine electromagnetic coupling

equations. The order of these matrices may vary, and their elements may be either constants or functions of X or of I , depending upon the assumptions made. All synchronous machine models based on the Park transformation can, however, be expressed in the form (1) and (2).

The Park equations relating flux, voltage and currents in the direct and quadratic axis can be interpreted in terms of a number of coupled lossy electromagnetic circuits oriented along the two axes and identified with either rotor or stator phenomena. In practical implementations the number of rotor circuits represented is typically reduced to one or two per axis. Although this limits the accuracy of the synchronous machine representation, particularly as regards higher frequency phenomena, the available data on machine characteristics is seldom of sufficient detail to specify adequately the parameters of a greater number of circuits.

An important simplifying assumption that is normally accepted in the simulation of power systems is that the transient deviation of armature flux from the balanced sinusoidal form can be neglected. This assumption is consistent with the use of a steady state network solution algorithm. Other simplifying assumptions of the Park equations may also be introduced to obtain an appropriate balance between model complexity, data requirements and computational efficiency. In general, relatively simple generator models are adequate for first swing analysis, while more complex models are needed for longer term studies where damping effects must be accurately represented.

Saturation of magnetic flux with magnetomotive force is represented in some approximate form in all but the simplest models as it can have a major impact on simulation results. On the other hand, it has been common practice to neglect the effect of off-nominal generator speed by neglecting the ω/ω_0 terms appearing in the Park equations. This was a computational convenience in network analyzer and analog computer work which was carried over into early digital simulation programs. While neglect of this speed deviation effect is reasonable in simple transient stability studies, it is not acceptable in either load rejection studies or in studies of system separation and under-frequency behavior. In load rejection simulations in hydro systems, the over-frequency is a significant contributor to the total over-voltage produced. In load shedding studies the fall in voltage with falling machine speed must be modeled because it is one of the key factors affecting the fall of total system load as system frequency falls.

It could be argued that it is improper to consider the generator speed deviation terms without also considering the variation of network parameters, particularly line charging capacitance and shunt compensation, with frequency. The more advanced simulation programs presently in use [3,4] can represent the frequency dependence of

all network elements, hence favoring the inclusion of the speed deviation terms in all machine simulation models.

Network Model

The general network equations may be written as follows:

$$\begin{bmatrix} \underline{I}_G \\ \underline{I}_L \end{bmatrix} = \begin{bmatrix} \underline{Y}_{GG} & \underline{Y}_{GL} \\ \underline{Y}_{LG} & \underline{Y}_{LL} \end{bmatrix} \begin{bmatrix} \underline{E}_G \\ \underline{E}_L \end{bmatrix} \quad (3)$$

For load buses:

$$\underline{I}_{L_k} = L(\underline{E}_{L_k}) \underline{E}_{L_k} \quad (4)$$

where subscripts L and G denote load and external generator buses, respectively.

Solution Process

For the purpose of illustration equation (3) can be expressed in impedance form:

$$\begin{bmatrix} \underline{E}_G \\ \underline{E}_L \end{bmatrix} = \begin{bmatrix} \underline{Z}_{GG} & \underline{Z}_{GL} \\ \underline{Z}_{LG} & \underline{Z}_{LL} \end{bmatrix} \begin{bmatrix} \underline{I}_G \\ \underline{I}_L \end{bmatrix} \quad (5)$$

The key problem in the dynamic simulation process is that $\underline{I}$ must be determined before the machine differential equations can be integrated over a timestep. To solve for $\underline{I}$, (2) and (5) or (3) must be solved simultaneously. Substitute (2) into (5),

$$\begin{bmatrix} \underline{Z}_{GG} + \underline{Z}_G & \underline{Z}_{GL} \\ \underline{Z}_{LG} & \underline{Z}_{LL} \end{bmatrix} \begin{bmatrix} \underline{I}_G \\ \underline{I}_L \end{bmatrix} = \begin{bmatrix} [\underline{H}] \underline{X} \\ \underline{E}_L \end{bmatrix} \quad (6)$$

Equation (6) may be recognized as that of an augmented electric network consisting of the original network connected between machine terminals plus new branches, characterized by the elements of $[\underline{Z}_G]$, connected radially at each generator terminal node.

Given the algebraic expression (6) of the relationship between machine and network currents and voltages, the dynamic simulation proceeds according to the following basic steps:

- a) With the state variables, $\underline{X}$, known determine the machine internal voltage $[\underline{H}] \underline{X}$.

- b) Solve (6) for the generator currents I_G .
- c) Compute dX/dt from (1).
- d) Use a suitable numerical integration procedure to determine new values of X .
- e) Execute output operations, update time, and return to step a).

Equation (6) can be solved efficiently by means of the simultaneous displacement Z-matrix method mentioned in Appendix 1 in which the factorized Y-matrix need not be modified except at the timesteps where there are changes in the network due to switching. Except in the special case of all load represented by a constant impedance ($L(E_L) = \text{constant}$), equations (4) are nonlinear, necessitating an iterative solution process.

The full Newton method will require fewer iterations than the factorized Y-Z-matrix method due to its quadratic convergence. However, the retriangularization of the Jacobian is time consuming and when constant Jacobians are used for the sake of efficiency, strict quadratic convergence is lost.

Integration Methods

Most large scale stability programs use explicit integration methods such as those of Euler or Runge-Kutta. These methods are easy to program and allow for easy adjustment of existing equipment models or the addition of new types of models. In recent years, so-called implicit integration techniques have been proposed for use in dynamic stability analysis for power systems [5], but as yet little published material is available on their performance relative to the more traditional integration methods.

A conscious choice must be made in dynamic stability studies as to the range of phenomena one is interested in observing. For maximum efficiency one should not include in the representation very small time constants which represent phenomena that are not of importance for the dynamic response of interest. The reason for this is that while the total simulation time required is a function of the time constant for the slowest phenomenon one is interested in, the integration timestep required to avoid numerical instability is determined largely by the smallest time constants included whether or not the phenomena they represent are of interest for the particular solution.

However, if this smallest time constant is an open circuit time constant for a generator, the effective smallest time constant is a function of the network condition at the time and cannot be readily estimated by inspection. The effective time constant is normally significantly smaller than the specified open circuit generator time constant and the permissible timestep must be chosen accordingly.

An important consideration is that the results from a numerically instable simulation may be mistaken for actual system instability resulting in erroneous study conclusions.

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APPENDIX 3

DISTRIBUTION FACTOR METHODS

Derivation of Distribution Factors

Frequently, it is desired to know how network current and power flow may change with generation changes, or by removal or insertion of a branch element in the network. The distribution factor method has long been used to provide estimates of such changes [1]. Clearly, the most direct and precise method for determining such changes is through the use of the power flow analysis (load flow). By comparison of base and change cases, the impact of a change can be accurately assessed at least so far as the base case conditions apply to the problem at hand and so far as the change case represents the changed conditions.

Of equal interest to the full A.C. load flow solutions are linear system models which are used for a variety of studies where perturbations are made around a load flow solution. Two types of sensitivity coefficients are used in these studies, the sensitivity of a line's real power flow to the change in real power injection at any given bus, and the sensitivity coefficient of a line's power flow to the outage of a different line. These will be referred to as "a" and "d" coefficients respectively, and are defined as follows:

$$a_{l,i} = \frac{\text{the change in real power flow on line } l}{\text{the change in real power injection on bus } i} \quad (1a)$$

$$d_{l,k} = \frac{\text{the change in real power flow on line } l}{\text{the real power flow on line } k \text{ before it opened}} \quad (1b)$$

Most work to date with these factors has been done with real power loads, generation, and flows assuming voltage magnitude to be constant. These conditions often do prevail to a close enough extent to be quite useful. In general, variations in reactive flows and voltage magnitude are not linear with respect to injection changes or line outages.

Generation Shift Distribution Factors

The real power sensitivity coefficients can be derived by various techniques, the simplest being a perturbation of the system load model and then re-solving at the new conditions -- this method gives good accuracy but is very time-consuming compared to other techniques. The most common method uses the superposition principle in such a way that the coefficients are obtained quickly [1]. The derivation presented here is similar to that of Brown [2] or Stagg and El-Abiad [3] and results in identical sensitivity factors to those derived by other methods such as in Limmer [4]. See also current injection technique described in W.L. Snyder discussion of Reference 5.

In linearized form, the power transfer in a branch, P_{ij} , may be represented by:

$$P_{ij} = \frac{1}{x_{ij}} (\theta_i - \theta_j) \quad (2)$$

where

θ_i, θ_j are phase angles of buses i, j respectively

bus i phasor voltage = $1 \angle \theta_i$

bus j phasor voltage = $1 \angle \theta_j$

x_{ij} is the branch reactance

Using this linearized form then allows writing the equation for net power injection at buses as a linear function of phase angles:

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}} (\theta_i - \theta_j) \quad (3)$$

j are nodes connected directly to i .

Then in matrix form:

$$\begin{bmatrix} P_1 \\ P_2 \\ \vdots \end{bmatrix} = \begin{bmatrix} \frac{1}{x_{1j}} \\ \vdots \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \vdots \end{bmatrix}$$

or

$$\begin{bmatrix} \theta_1 \\ \theta_2 \\ \vdots \end{bmatrix} = \begin{bmatrix} X \\ \vdots \end{bmatrix} \begin{bmatrix} P_1 \\ P_2 \\ \vdots \end{bmatrix}$$

In practice, the system X matrix is not used as shown above, but is partitioned for the following reason. What is sought in deriving sensitivity coefficients is a relationship between changes in injections (ΔP_i) and changes in line power flows (ΔP_{ij}). By definition, the angle of the reference bus is invariant; hence, $\Delta \theta_{ref}$ must be zero. Further, ΔP_{ref} cannot be specified independently of the remaining ΔP 's. To accommodate this singular condition, it is customary to solve for the $n-1$ θ 's involving the $n-1$ power injections by "grounding" the swing bus; that is, allowing the power injection at the swing bus to be a dependent variable.

Let $[B']$ be the susceptance matrix formed by grounding the reference bus, and $\Delta P'$ and $\Delta \theta'$ be the power injection and bus angle change for the $n-1$ buses. It follows that:

$$\Delta P' = [B'] \Delta \theta' \quad (4a)$$

$$\text{or } \Delta \theta' = [X'] \Delta P' \quad (4b)$$

Thus, if an incremental vector of power flow is desired, the following relationships may be used:

$$\Delta P_{ij} = \frac{1}{x_{ij}} (\Delta \theta_i - \Delta \theta_j) \quad (5)$$

Suppose $\Delta P'$ is set to zero at all buses except bus g ($\Delta P_g \neq 0$), then the procedure to find the generation shift factors for injections at bus g is as follows:

- 1) Solve for $\Delta \theta_i$ in (4a) by sparsity coded Gaussian elimination.
- 2) Solve for ΔP_{ij} according to (5).
- 3) Find $a_{ij,g} = \frac{\Delta P_{ij}}{\Delta P_g}$.

The generation shift factors may be assembled in a matrix $[A]$ with dimensions: number of lines by number of generators.

Summary of Generation Shift Distribution Factor Calculation

Influence of injection at bus g on flow change in circuit k_{ij} :

FIGURE 1

DC Load Flow	$\Delta \theta = [X] \Delta P$
For injection at bus g of ΔP_g	$\Delta \theta_i = x_{ig} \Delta P_g$ $\Delta \theta_j = x_{jg} \Delta P_g$ $\Delta P_{ij} = \frac{(\Delta \theta_i - \Delta \theta_j)}{x_{ij}}$ $a_{ij,g} = \frac{\Delta P_{ij}}{\Delta P_g} = \frac{(x_{ig} - x_{jg})}{x_{ij}}$

Line Outage Distribution Factors

A line outage may be modeled by adding two power injections to a system, one at each end of the line to be dropped. The line is actually left in the system but the effects of its being dropped are modeled by injections. The injections must thus be solved in the following manner. A line from bus n to bus m will be dropped. To model this outage, injections ΔP_n and ΔP_m will be imposed at buses n and m , respectively. Using the previously derived equation relating $\Delta \theta$ to ΔP , we have:

$$\Delta \theta' = [X'] \Delta P' \quad (4b)$$

Define a sensitivity factor δ as the ratio of the change in a phase angle θ_i anywhere in the system to the original power P_{nm} flowing over the line nm before it was dropped. That is:

$$\delta_{i,nm} = \frac{\Delta \theta_i}{P_{nm}} \quad (7)$$

If neither n nor m is the system reference bus, two injections, ΔP_n , ΔP_m ($= -\Delta P_n$), are imposed at buses n and m . This gives a change in phase angle at bus i equal to:

$$\Delta \theta_i = X'_{in} \Delta P_n + X'_{im} \Delta P_m \quad (8)$$

Then using the relationship between ΔP_n and ΔP_m , the resulting δ factor is:

$$\delta_{i,nm} = \frac{(X'_{in} - X'_{im}) x_{nm}}{x_{nm} - (X'_{nn} + X'_{mm} - 2X'_{nm})} \quad (9)$$

where primed (capital) symbols are bus matrix elements and non-primed (lower case) symbols are circuit impedances.

If either n or m is the reference bus, only one injection is made (since an injection cannot be made at the reference). The resulting factors are:

$$\begin{aligned} \delta_{i,nm} &= \frac{X'_{in} x_{nm}}{(x_{nm} - X'_{nn})} \quad \text{for } m = \text{ref.} \quad (10) \\ &= \frac{-X'_{im} x_{nm}}{(x_{nm} - X'_{mm})} \quad \text{for } n = \text{ref.} \end{aligned}$$

If bus i itself is the reference bus, then $\delta_{i,nm} = 0$ since the reference bus angle is constant.

If the δ factors for a particular line outage (nm) are arranged in a vector, the line outage sensitivity factors $\underline{d}$ may be defined as follows:

$$\Delta P = \begin{bmatrix} 1 \\ x_{ij} \end{bmatrix} [I_n] \delta P_{nm} \quad (11a)$$

$$\Delta P = \underline{d} P_{nm} \quad (11b)$$

where $[I_n]$ is the bus incidence matrix

and $\begin{bmatrix} 1 \\ x_{ij} \end{bmatrix}$ is a diagonal matrix of circuit admittances

A line outage distribution factor matrix $[D]$ may now be defined consisting of one column $\underline{d}$ for each line outage of interest. The elements of this matrix are:

$$d_{ij,m} = \frac{\Delta P_{ij}}{P_{nm}} \quad (11c)$$

where nm is the line being dropped.

The procedure for calculating the line outage distribution factors appears in Figure 2. One notes that by definition:

$$d_{ij,nm} \equiv (\delta_{i,nm} - \delta_{j,nm})/x_{ij} \quad (12)$$

Summary of Line Outage Distribution Factor Calculation

The effect of circuit mn outage on ij flow before outage is shown in Figure 2:

FIGURE 2

After outage of circuit mn: place couplet $+\Delta P_m, -\Delta P_m$ at buses m,n to balance flow that would flow if circuit mn were in place as shown in Figure 3:

FIGURE 3

Using the generation shift distribution factors:

$$\begin{aligned} \Delta P_{mn} &= a_{mn,m} \Delta P_m + a_{mn,n} \Delta P_n \\ &= (a_{mn,m} - a_{mn,n}) \Delta P_m \end{aligned}$$

$$\text{Flow } \Delta P_{ij} = (a_{ij,m} - a_{ij,n}) \Delta P_m$$

$$\text{but } P_{mn}^0 = P_{mn} + \Delta P_{mn} = \Delta P_m$$

$$\therefore = P_{mn} + (a_{mn,m} - a_{mn,n}) \Delta P_m$$

$$\text{and } \therefore \Delta P_m = \frac{P_{mn}}{[1 - (a_{mn,m} - a_{mn,n})]}$$

Hence:

$$d_{ij,nm} = \frac{\Delta P_{ij}}{P_{mn}} = \frac{(a_{ij,m} - a_{ij,n})}{[1 - (a_{mn,m} - a_{mn,n})]} \quad (13)$$

Substituting the values for the generation shift factors in terms of the bus reactance matrix terms X' 's and line reactances x 's yields:

$$d_{ij,nm} = \frac{X'_{im} - X'_{jm} - (X'_{in} - X'_{jn})}{x_{mn} + 2X'_{mn} - X'_{mm} - X'_{nn}} \frac{x_{mn}}{x_{ij}} \quad (14)$$

Note we have assumed a symmetric X' matrix $X'_{ij} = X'_{ji}$.

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APPENDIX 4

AC CONTINGENCY MODELS

Three different approaches to fast approximate ac load flow have been identified and their characteristics summarized in this appendix. These are:

1. Decoupled Newton Load Flow
2. Z-matrix Method
3. Sensitivity Methods

The special technique commonly used to simulate circuit outages without directly modifying the system matrix is described in Section 4 of this appendix. An automatic means of selecting severe contingencies for study is described in Section 5.

1.0 AC CONTINGENCY ANALYSIS BY DECOUPLED LOAD FLOWS

In 1972, Peterson, Tinney, and Bree [1] presented an approximate ac load flow procedure which they termed the Iterative Linear Power Flow (ILPF). The method is a decoupled load flow along the lines discussed in Appendix 1. This method is capable of iteration to an exact ac load flow solution without refactorization between iterations. Circuit outages are accounted for by use of the Sherman-Morrison Algorithm described in Section 4.0 of this appendix. Solution speed of the method is reported as 1.8 complete approximate load flows for each full Newton iteration. Presuming that the full Newton load flow may solve in about 4-6 iterations for change cases of this type, the ILPF method is nearly ten times as fast as the use of a standard full Newton.

The fast decoupled Newton load flow reported by Stott and Alsac in 1974 [2] is described in Appendix 1. Their formulation is even simpler than the ILPF method and is regarded by many as the "state-of-the-art method" for approximate ac load flow contingency solution, as well as for "exact" ac solutions. The Sherman-Morrison algorithm is also used in this case to avoid retriangularization of B' and B'' for circuit outages. Reference 2 reports acceptable accuracy for contingency studies after a single iteration in most cases (one solution of the reactive power voltage magnitude equation). It is reported that it is faster to use the Sherman-Morrison algorithm for contingencies encompassing up to three circuit outages. For more than three simultaneous outages it is faster to perform a complete retriangularization of B' and B'' .

The distinct advantage of decoupled load flow methods for fast approximate ac load flows is that a solution of specified accuracy is obtainable. Therefore, for outages where one single iteration is adequate, high speed is obtained while the iterative solution will automatically be provided to obtain adequate accuracy for contingencies with large voltage excursions.

2.0 Z-BUS METHOD

The Z-matrix method is not competitive with full Newton or decoupled Newton techniques for general purpose load flow or contingency studies where the entire load flow solution is desired. The strength of the Z-matrix approach is that each element of the matrix by itself gives the sensitivity between a current injection at a bus and the voltage at the same or another bus. Thus, on a large system, if one is interested only in the voltage at a few buses or the flows on a few lines for a variety of conditions, it may well be that a Z-matrix procedure can be found that is significantly faster than competitive methods. Philosophically, Z-matrix approaches may be put in the same class as distribution factor methods. By precomputing network related factors (Z-matrix elements or derivatives of these) one can rapidly compute selected voltages, currents or powers for the type and scope of system conditions covered by the precomputed factors.

In a 1977 paper, Brown [3] proposes an ac contingency method capable of efficiently estimating voltages at a few selected buses for line outage contingencies. Basically, this method involves the following steps:

1. The bus K for which voltages during contingencies are desired is selected.
2. A Z-matrix for the base system having an arbitrary impedance between bus K and ground is constructed. There are no other impedances to ground.
3. After the construction of the Z-matrix, the arbitrary ground tie at bus K is replaced by a ground tie which impedance is such that a single current injection at a near-by fixed voltage (generator) bus N will produce base case voltage at both buses K and N. There are no other current injections applied.
4. The Z-matrix is modified for a specified line outage.
5. With the modified Z-matrix and the same ground tie impedance evaluated under 3. a new current injection is computed at bus N that will maintain the constant voltage at this bus.
6. The voltage at bus K during the contingency is calculated as the voltage on the modified ground tie caused by the new injection current.
7. The voltage at bus K for other circuit outages is obtained by repeating steps 4, 5, and 6.
8. If a voltage at another bus is desired, the base case Z-matrix is modified by adding an arbitrary ground tie to this

bus and removing the ground ties at the previously listed bus. The entire process 3 through 7 is then repeated for the desired contingencies.

According to Brown [3], all steps in this process except step 2 are carried out with "millisecond" speed. The process may then be of interest where the voltage at only a few buses needs to be evaluated for each contingency. The method is approximate and depends on fairly constant X/R ratios throughout the system and a small angle between the test bus and the constant voltage bus. If the "constant voltage bus" does not have enough var support to remain constant during a particular contingency the results are invalid. Also the method is restricted to a constant impedance load representation.

3.0 SENSITIVITY METHODS

The Newton load flow is based on equation (3.1):

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J \end{bmatrix} \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} \quad (3.1)$$

where the elements of the Jacobian matrix are

$$\frac{\partial P_i}{\partial \theta_j}, \frac{\partial P_i}{\partial V_j}, \frac{\partial Q_i}{\partial \theta_j} \text{ and } \frac{\partial Q_i}{\partial V_j}.$$

The inverse of the Jacobian is referred to as the sensitivity matrix as it gives the sensitivity of voltages to bus injections.

$$\begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} = \begin{bmatrix} J \end{bmatrix}^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \quad (3.2)$$

With much the same philosophy as one applies distribution factors or the Z-matrix approach described in the preceding, one can use these sensitivities to estimate bus voltages as a function of power injections (generator and load changes) [4] or as a function of network configuration.

In 1974, Sachdev and Ibrahim used sensitivity techniques to simulate circuit outages and tap changes of transformers and phase shifters by evaluating and applying corresponding changes in the complex power injections at the end buses of the circuit element considered. Briefly, the method is based on finding the power injections in Figure 3-1 that make the net flow between the two end buses of the outaged line = 0. With these injections determined (a special iterative procedure on at most 12 simultaneous equations is required), the voltage changes at any bus due to the simulated line outage can be obtained. The procedure is rapid as at most four power injection elements are different from the base case (ΔP and ΔQ at each of the two end buses).

FIGURE 3-1

This method is claimed to be comparatively fast and to give good results when a suitable set of power injection modification factors is used during the iterative computations of the power injection changes. However, evaluation of these factors requires load flow studies with simulation of line outages by a slower, more accurate technique such as Newton load flow assuming medium load conditions. Thus it requires additional off-line computations. Power injection modification factors may lead to appreciable errors when used for a base case state which is totally different from the state at which they were calculated. [6]

Mamandur and Berg [6] have presented a similar approach, but utilize the admittance matrix connected for the circuit outage(s) in the computation of bus injections.

The sensitivity methods are based on the tacit assumption that the linearization around the base case operating point represented by the base case Jacobian can be used to compute the change in voltage due to a line outage. It seems that one may expect accurate results when the outage is not critical from a voltage standpoint, and progressively less accurate results as the voltage excursion increases.

4.0 SHERMAN-MORRISON ALGORITHM

Instead of refactorizing the Y matrix or any other system matrix whenever a circuit is removed or added to the system, the following procedure can be used: [7]

For a given I in the equation:

$$\underline{I} = [\underline{Y}_0] \underline{E}_0 \quad (4.1)$$

a solution for E :

$$\underline{E}_0 = [\underline{Y}_0]^{-1} \underline{I} \quad (4.2)$$

can be obtained by factorizing Y and solving by means of backward and forward substitution. The

outage of a circuit between buses k and m can be reflected in $[Y]$ in the following fashion:

$$[Y_1] = [Y_0] + b \underline{M} \underline{M}^T \quad (4.3)$$

where b is the circuit series admittance

$\underline{M}$ is the column vector with all elements zero except for 1 at element k and -1 at element m

It can be shown that:

$$[Y_1]^{-1} = [Y_0]^{-1} + \frac{[Y_0]^{-1} \underline{M} \underline{M}^T [Y_0]^{-1}}{-1/b + \underline{M}^T [Y_0]^{-1} \underline{M}} \quad (4.4)$$

or

$$[Y_1]^{-1} = [Y_0]^{-1} + c \underline{X} \underline{M}^T [Y_0]^{-1} \quad (4.5)$$

$$\text{where } c = (-1/b + \underline{M}^T \underline{X})^{-1} \quad (4.6)$$

$$\underline{X} = [Y_0]^{-1} \underline{M} \quad (4.7)$$

Thus the solution to the outage case is:

$$\begin{aligned} \underline{E}_1 &= [Y_1]^{-1} \underline{I} \\ &= [Y_0]^{-1} \underline{I} + c \underline{X} \underline{M}^T [Y_0]^{-1} \underline{I} \\ &= \underline{E}_0 + c \underline{X} \underline{M}^T [Y_0]^{-1} \underline{I} \end{aligned} \quad (4.8)$$

The steps required to obtain the modified solution for an outage is thus:

1. Define $\underline{M}$ to represent the outage.
2. Solve for $\underline{X} = [Y]^{-1} \underline{M}$ using the prefactorized Y matrix
3. Compute c (equation 4.6)
4. Compute the adjustment according to equation (4.8).

The above procedure may be applied recursively for simultaneous outages:

- Let (a) represent circuit A out
 (b) represent circuits A and B out
 (c) represent circuits A and B and C out

$$\begin{aligned} \text{Then: } \underline{E}_a &= \underline{E}_0 + c_a \underline{X}_a \underline{M}_a^T \underline{E}_0 \\ \underline{E}_b &= \underline{E}_a + c_b \underline{X}_b \underline{M}_b^T \underline{E}_a \\ \underline{E}_c &= \underline{E}_b + c_c \underline{X}_c \underline{M}_c^T \underline{E}_b \end{aligned}$$

When more than three simultaneous outages need to be represented, it is usually more efficient to refactorize Y .

5.0 AUTOMATIC CONTINGENCY SELECTION

Exhaustive contingency testing including all conceivable contingencies, becomes prohibitively long-running and costly when all primary contingencies, each with additional levels of secondary contingencies are involved. On the other hand, applying contingency testing to a subset of contingency cases selected on the basis of the planner's experience and intuition may be inadequate due to the possibility of omitting some critical cases.

A fast method for preranking contingencies was developed by Fischl and Puntel [8] for dc load flow contingencies and applied to both transmission expansion and reliability programs [10]. The method which utilizes Tellegen's theorem [11] generates the sensitivities of a system-wide performance index with respect to the outages. The contingency ranking according to severity is accomplished by ordering these normalized sensitivities from the greatest to the smallest.

In a 1978 paper, Ejebe and Wollenberg [12] expanded the method to include contingency ranking based on the severity of voltage problems as well. The method uses the non-linear ac load flow equations for the evaluation of the effect of transmission and generation outages on a voltage quality system-performance index and uses the simple dc load flow model to rank contingencies with respect to real power flows. As such, the method does not explicitly indicate whether a contingency is going to give bus voltage or circuit overload problems. Rather, it indicates the severity of each contingency relative to the others. Full ac load flows or adequate approximate solutions must still be carried out—but only on the "problem" cases. Furthermore, what constitutes the set of "problem" cases is easily determined by simply running the load flow for each case starting at the top of the list and stopping when the cases do not give problems. The cases below the stopping point need not be checked since they are already ranked in severity below the cases at the stopping point. In this manner, the method constitutes an adaptive contingency processor since the number of cases solved will vary depending upon system conditions. Such an adaptive contingency process is shown in Figure 5-1.

FIGURE 5-1

ADAPTIVE CONTINGENCY PROCESSOR

The procedure for computing the required performance index sensitivities with respect to line and generator outages for the circuit overload problem is discussed in Appendix 8. Briefly, the overload performance index is defined as:

$$PI_{MW} = \sum_{l=1}^{NL} \frac{W_l}{2n} \left(\frac{P_l}{P_l^{Lim}} \right)^{2n} \quad (5.1)$$

where:

- P_l = The megawatt flow of line l , (calculated by the dc load flow model)
- P_l^{Lim} = The megawatt capacity of line l
- NL = The number of lines in the system
- n = Specified exponent ($n = 1$ preferred)
- W_l = Real non-negative weighting coefficient; may be used to reflect the importance of some lines.

The performance index PI_{MW} contains all line flows normalized by their limits. These normalized flows are raised to an even power, thus the use of absolute magnitude of flows is avoided. This index PI_{MW} has a small value, when all line flows are within their limits, and a high value when there are line overloads. Thus, it provides a good measure of the severity of line overloads for a given state of the power system.

The sensitivities $\frac{\partial PI_{MW}}{\partial B_{ij}}$ or $\frac{\partial PI_{MW}}{\partial P_i}$ for line

admittance and power injection respectively are compiled by the techniques described in Appendix 8 and the basis for contingency ranking obtained by multiplying these sensitivities by the admittance of the circuit or the power of the generator outages.

The voltage level performance index chosen to quantify system deficiency due to out-of-limit bus voltages is defined by

$$PI_V = \sum_{i=1}^{NB} \frac{W_{V_i}}{2n} \left(\frac{|V_i| - |V_i^{SP}|}{\Delta V_i^{Lim}} \right)^{2n} \quad (5.2)$$

where:

- $|V|$ = Voltage magnitude at bus i
- $|V_i^{SP}|$ = Specified (rated) voltage magnitude at bus i
- ΔV_i^{Lim} = Voltage deviation limit, above which voltage deviations are unacceptable
- n = Exponent of penalty function ($n = 1$ preferred)
- NB = Number of buses in the system
- W_{V_i} = Real non-negative weighting factor.

The voltage deviation ΔV_i^{Lim} represents the threshold above which voltage level deviations are outside their limit. Any contingency load flow with voltage levels outside this limit yields a high value of the index PI_V . On the other hand, when all the voltage level deviations from the rated (nominal) voltage are within ΔV_i^{Lim} the voltage performance index PI_V is small. Thus, this index measures the severity of the out-of-limit bus voltages, and for a set of contingencies, this index provides a direct means of comparing the relative severity of the different outages on the system voltage profile.

As it stands, equation 5.2 is ignorant of the reactive limits of generators that may be influenced by the severity of contingencies. In Reference 12, this consideration is accommodated by adding to the performance index the term:

$$\sum_{i=1}^{NG} \frac{W_{Q_i}}{2n} \left(\frac{Q_i}{Q_i^{Max}} \right)^{2n} \quad (5.)$$

where:

- Q_i = Reactive power produced at bus i
 Q_i^{Max} = Reactive power production limit
NG = Number of generating (reactive production) units
 W_{Q_i} = Real non-negative weighting factor.

The second summation, taken over all reactive production units, penalizes any violations of the reactive power constraints. The reactive power weighting factors are set to zero if the effect of the reactive power deficit is not required.

The sensitivities of the voltage performance index with respect to all single outages is obtained by the solution of two ac load flows.

The ranking algorithm does not give a perfect ordering by severity and requires the user to tune the adaptive stopping criterion to balance the overall execution time with the desired margin of error to assure that all possible troublesome combinations are covered.

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APPENDIX 5

AUTOMATIC CONTINGENCY SELECTION METHOD

This description of the approach is from the IEE Conference Publication No. 148, February 1977.

A PROGRAM FOR COMPOSITE BULK POWER ELECTRIC SYSTEM ADEQUACY ASSESSMENT

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INTRODUCTION

A program for composite bulk power electric system adequacy assessment, PCAP, is under joint development by the Northeast Power Coordinating Council (NPCC) and by Power Technologies Inc. (PTI) of Schenectady, NY, U.S.A. NPCC consists of the principal electric utilities in New York and New England in the Northeast United States, and of Ontario Hydro and the New Brunswick Electric Power Commission in Canada. The program, PCAP, is to be used to assess the composite effect of generation and transmission unavailability on the overall adequacy of a complex electric power supply system.

Bulk power supply adequacy assessment involves the prediction of the risks of load isolation (curtailment) and system over-stress arising from the coincidence of given load distributions with unscheduled outage of transmission and generation facilities. Adequacy indices for bulk power supply performance may be developed for region wide, system, and bus assessment. These indices measure both event severity such as degree of overload and amount of load isolated (curtailed) and event likelihood such as the probability and frequency of event occurrence. Indices which measure the risks of occurrence of overload conditions in circuits, cables, and transformers provide means to identify potentially weak bulk power supply segments.

It is recognized that adequacy is but one measure of the reliability of a bulk power supply system. However, static adequacy assessment is the most practical method presently available for analysis of bulk power supply systems.

The program described in this paper computes risk indices by solving an electrical model of the system for various generation and transmission outages, checking for overload or isolation conditions or "failures"; and, if a failure occurs, calculating its probability and frequency of occurrence. The types of failures which are recognized include capacity deficiencies, circuit overloads, and load isolation.

General Program Description

An important feature of this program is its ability to automatically select and subsequently test specific outages deemed most likely to produce system failure conditions. This method substantially reduces the number of contingency cases that must be tested to determine the adequacy of a bulk power supply system. The automatic selection is accomplished by a computationally efficient technique that calculates the sensitivity of circuit power flows to generation and circuit outages (Puntel et al (1)). System

outages likely to result in large power flows on circuits are then ranked according to projected impact. By combining this approach with the improbability of outage events involving many elements out-of-service, it is possible to greatly reduce the number of studies required to assess risks of power transmission system overloads.

Contingency checks are made in the order of the outage rank; power flow studies are executed and the system risks of overload and separation determined. The program is presently equipped to investigate up to two overlapping statistically independent generation and/or transmission events. Each event may involve commonly affected transmission and/or generation elements including models of lines on the same right-of-way, and plant capacity loss. For each distinct outage event the program checks for system failures, identified as overloaded lines, insufficient capacity, or load isolation.

PCAP uses a rapid (DC) load flow technique to simulate the system conditions for each outage event considered. The technique takes advantage of the fact that the response of the system to changes in real power flow (MW) is quasi-linear and it neglects the less linear response of the system resulting from changes in reactive power flows. Consideration of these non-linear responses would require a more time-consuming technique. The penalty for using the faster load flow technique is that no knowledge of system voltages or reactive requirements is obtainable. Therefore, PCAP is able to simulate element overload situations but not unsatisfactory voltage conditions. Studies and tests have indicated feasible extension of the technique with decoupled load flow algorithms.

A remedial dispatch subroutine is provided with user activation option. If an overloaded line condition exists, the program control option automatically performs remedial action by redispatching generation. The redispatch logic employs sensitivity factors to determine a favorable overload relief strategy. These factors indicate where generation should be increased and decreased to reduce circuit overloads. This remedial dispatching feature is more commonly used in operations contingency assessments than in planning studies.

In the context of this program, a contingency is considered to be the unscheduled outage of a component or group of components of the electric bulk power supply system. Contingencies are divided into two broad categories, primary and secondary. A primary contingency is one that occurs with no other outages previously in effect (first contingency from an established system base condition). A base case DC load flow solution is obtained first. Depending on the outcome

of this solution, a set of primary contingencies is selected. They can consist of either program selected contingencies based on the performance index or user specified contingencies. The exact number of program selected contingencies must be specified. For each primary contingency, not resulting in a system failure, a predetermined number of program selected secondary contingencies are tested. Figure 1 illustrates the program logic and computational sequence.

Risk indices. Several risk indices are developed by PCAP to aid bulk power system adequacy assessment indicated in Figure 2. These may be grouped in four categories:

1. Capacity Reserve Assessment: Probability and frequency of reserve deficiency;
2. Contingency Overload Risk: Probability and frequency of specific contingency events;
3. Circuit Overload Failures: Number of contingencies causing specified circuits to be overloaded, probability, frequency, and expected value of overload, magnitude and contingency causing worst overload;
4. Area isolation with load not served: Number of events, probability and frequency of separation, "MW not served".

The "MW not served" index is formed from the sum of the products of event frequency, f_i , and event load curtailment, MW_i ,

$$\text{"MW not served"} = \sum_i f_i \cdot MW_i \quad (1)$$

The formation of the capacity and transmission contingency probability and frequency follows conventional methods for independent overlapping event predictions (Billinton et al (2)).

Event formation. The program is designed to accommodate "common mode" events involving several transmission facilities. Thus, loss of circuits on the same right-of-way may be modeled as a common mode outage event to represent the single cause which may affect several lines in common. Such an event may occur during or preceding another event involving other transmission or generation facilities.

Component failure rate and repair information are necessary for event frequency and probability determination. Line outage models provide for line terminal and for line section causes. Line section exposure is assumed proportional to line length. Generator outage models normally applied in generation reserves assessment are used. Transformers are modeled as branches.

Extensions. It was determined early in the process of program development, that a common reliability index "the megawatt load curtailment per megawatt load served" would be most desirable. Given the program's intrinsic capability of performing intelligent remedial adjustments whenever system constraints have been exceeded, inadequacy is then measured by the amount selective loads must be curtailed as the final remedial step for the system to remain within permissible limits.

Preliminary tests utilizing upper bound linear programs indicate that a feasible algorithm exists for the determination of minimum load curtailment relative to overloaded facilities. This algorithm, together with techniques to exploit the sparsely linked characteristic of bulk power networks, can be applied to solve large network problems efficiently.

The load curtailment index offers a useful measure of the adequacy of a proposed system configuration. Judiciously, it could be used to compare design influence on adequacy, a function of various system configurations. The index derived from the program will be expressed on a per unit basis. Thereby, systems of various sizes or a system as it develops through time can be compared from an adequacy point of view. If a simple load curtailed value were employed, no realistic system comparison could be made.

Program extension to automatically investigate and accommodate up to five overlapping system contingencies is under development along with modeling capability to handle phase shifting transformers. The five overlapping independent events can be comprised of combinations of three circuit contingencies and two capacity contingencies or five capacity contingencies. This expanded analytical capability should provide system planners with a method to assess system adequacy, especially when investigating multiple contingencies.

Example study. A sample study of two complex and interconnected areas is provided. The system consists of 128 busses and 245 lines. Figure 3 indicates the characteristic data of the two areas analyzed. Total system capacity is 28,500 MW and system load is 20,500 MW. The total pool was analyzed first. One hundred primary contingencies and 10 secondary contingencies per primary contingency were specified. No remedial dispatch was permitted in this study. A total of 606 contingencies was selected and studied by the program. Of these, 64 were judged failures due to unreconciled line overloads, and an additional four were failures by nature of buses isolated with insufficient generating capacity to support the load. Table 1 illustrates summary results for contingencies resulting in line overload and load bus isolation, respectively. Each of the two areas is analyzed separately to demonstrate the capability of the program to analyze subsystems or areas and to present the result in a form that may be readily combined to predict the performances of the interconnected system. In each area analysis, 50 primary contingencies were permitted in the particular area while ten secondary contingencies were permitted from candidates in both areas. The summary results for these two runs are provided in Table 1. The equivalence of the composite results from the individual area studied with those obtained from the pool analysis may be determined by inspection.

SUMMARY

A program for the adequacy assessment of bulk power electric systems has been developed and is now operational. The program has been tested on systems up to a size of 375 buses and applied to planning

The salient feature of the program is its ability to automatically select and subsequently test contingencies deemed likely to produce system failure conditions. The utilization of such a technique lends itself to a large and complex power system, as exists within the boundary of NPCC.

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graph TD
    START([START]) --> READ[/READ INPUT DATA FILE/]
    READ --> ORGANIZE[ORGANIZE AND DISPLAY DATA]
    ORGANIZE --> CALCULATE[CALCULATE PROBABILITY AND FREQUENCY TABLES]
    CALCULATE --> DISPLAY[CALCULATE AND DISPLAY BASE CASE LOAD FLOW]
    DISPLAY --> DETERMINE[DETERMINE MOST SEVERE PRIMARY CAPACITY AND CIRCUIT CONTINGENCIES]
    DETERMINE --> TEST_PRIMARY[Test ALL PRIMARY CONTINGENCIES TO DETERMINE UNCONDITIONAL FAILURES]
    TEST_PRIMARY --> TEST[TEST PRIMARY CONTINGENCY]
    TEST --> DETECTED1{SYSTEM FAILURE DETECTED?}
    DETECTED1 -- YES --> REMEDIAL1[ATTEMPT REMEDIAL ACTION]
    DETECTED1 -- NO --> RESULTS1[/DISPLAY RESULTS OF CONTINGENCY/]
    REMEDIAL1 --> RESULTS1
    RESULTS1 --> SUCCESSFUL1{REMEDIAL ACTION SUCCESSFUL?}
    SUCCESSFUL1 -- YES --> DETERMINE2[DETERMINE MOST SEVERE SECONDARY CAPACITY AND CIRCUIT CONTINGENCIES]
    SUCCESSFUL1 -- NO --> TEST
    DETERMINE2 --> TEST_SECONDARY[Test SECONDARY CONTINGENCY USING PRIMARY CONTINGENCY AS BASE CASE]
    TEST_SECONDARY --> DETECTED2{SYSTEM FAILURE DETECTED?}
    DETECTED2 -- YES --> REMEDIAL2[ATTEMPT REMEDIAL ACTION]
    DETECTED2 -- NO --> RESULTS2[/DISPLAY RESULTS OF CONTINGENCY/]
    REMEDIAL2 --> RESULTS2
    RESULTS2 --> RESTORE2[RESTORE PREVIOUS SECONDARY CONTINGENCY]
    RESTORE2 --> ANY_MORE2{ANY MORE SECONDARY CONTINGENCIES?}
    ANY_MORE2 -- YES --> TEST_SECONDARY
    ANY_MORE2 -- NO --> RESTORE1[RESTORE PREVIOUS PRIMARY CONTINGENCY]
    RESTORE1 --> ANY_MORE1{ANY MORE PRIMARY CONTINGENCIES?}
    ANY_MORE1 -- YES --> TEST_PRIMARY
    ANY_MORE1 -- NO --> SUMMARY[/DISPLAY SUMMARY OF RESULTS/]
    SUMMARY --> STOP([STOP])
  
```

Figure 1. PCAP Computational Sequence

TABLE 1 - Reliability Data Obtained from Pool and Individual Area Analysis

SYSTEM ANALYZED	No. of Circuit Overloads	Total Overload Probability	Subsystems with Load Not Served	Total Separation Probability	MW Not Served due to Separation
Area I & Area II	64	0.8194E-02	4	0.231E-06	0.173E-00
Area I	39	0.3611E-02	2	0.134E-06	0.493E-01
Area II	25	0.4582E-02	2	0.964E-07	0.124E-00

TOTAL SYSTEM MW LOAD = 20,499.8

MW Reserve = 8,000.2

Probability of Capacity Outage being greater than System Reserve = 0.323509E-02

Cumulative Frequency (per day) of Restoring Capacity Outage greater than Reserve = 0.824529E-02

*** CIRCUIT OVERLOAD FAILURES ***

CIRCUIT DESCRIPTION FROM TO	CKT NO	NO OL	TOTAL PROB	TOTAL FREQ	EXP VAL % CAP	WORST % CAP	LOC WORST
141 139	1	3	0.4231E-03	0.3516E-02	113.1	113.5	12
141 139	2	3	0.4231E-03	0.3516E-02	113.1	113.5	12
131 124	1	2	0.1444E-06	0.3485E-05	118.3	146.7	272

etc.

TOTAL NUMBER OF CIRCUIT OVERLOADS = 64

TOTAL PROBABILITY = 0.8194E-02

TOTAL FREQUENCY = 0.4434E-01

EXPECTED VALUE OF OVERLOADS = 129.64

CONTINGENCIES WHERE THESE EVENTS OCCURRED:

1	2	3	5	7	8	12	13	15	17	18
19	22	26	27	28	30	31	38	39	46	47

etc.

*** OVERLOAD ELIMINATIONS ***

TOTAL NUMBER OF OVERLOADS ELIMINATED BY REDISPATCH = 23

*** SUMMARY OF SYSTEM SEPARATION EVENTS ***

SEPARATIONS WITH LOAD NOT SERVED:

BUS	NAME	TOTAL PROB	TOTAL FREQ	MW NOT SERVED	% MWHR NOT SERVED	NO. EVENTS
202		0.964E-07	0.308E-05	0.124E-00	0.964E-05	2
133		0.134E-06	0.246E-05	0.493E-01	0.134E-04	2

TOTAL NUMBER OF EVENTS = 4

TOTAL PROBABILITY = 0.231E-06

TOTAL FREQUENCY = 0.554E-05

TOTAL MW NOT SERVED = 0.173E-00

% OF SYSTEM MWHR NOT SERVED 0.878E-07

CONTINGENCIES WHERE THESE EVENTS OCCURRED:

55	211	271	378
----	-----	-----	-----

Figure 2 Sample output of reliability data obtained from a PCAP run

APPENDIX 6

USE OF STRATIFICATION TECHNIQUES IN MONTE CARLO SIMULATION

One method of improving the accuracy of Monte Carlo estimates, or conversely reducing the number of trials, has been proposed [1]. The method is the stratification technique. In this method, one or more of the random variables in the problem are "stratified", that is, divided into intervals. Trials are then simulated with these variables confined to their stratification levels. The mean value of the performance index to be estimated is then expressed as the average of the conditional means:

$$m = \sum_{k=1}^S P_k m_k$$

and the variance of the estimate of m is

$$v = \sum_{k=1}^S P_k (m_k - m)^2 + \sum_{k=1}^S P_k v_k$$

where P is the probability that the stratified random variable belongs to the k 'th stratum,

m is the conditional mean of the performance index knowing that the stratified random variable belongs to the k 'th stratum,

V is the conditional variance of the performance index,

S is the number of stratification levels.

Now, one can choose the number of trials, n , for each stratum. If the total number of trials is to be n , then one can show that the best choice for n is given by

$$n_k = n P_k (v_k)^{1/2} / \sum_{k=1}^S P_k (v_k)^{1/2}$$

In reference [1], the stratified random variable is chosen to be the overall available power because transmission system failures are strongly related to this quantity. Furthermore, it is assumed that at low levels of available power, transmission system caused failures are infrequent because the network is usually capable of transmitting that power which is produced. At high levels of available power, transmission failures are also infrequent since there is usually enough power available locally to meet demand. At intermediate values of overall available power, transmission system caused failures are more frequent because transmission components are most needed at these overall power levels.

According to reference [1] the computation time requirement of Monte Carlo simulation can be reduced by more than 70 % by the use of the stratification method. It appears that the best stratification assumptions may be system dependent.

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APPENDIX 7

MEASURES OF WORTH OF SERVICE QUALITY

1.

One approach to the evaluation of the expected costs of electric power interruptions has been to attempt to establish a relationship between a general economic variable (e.g., Gross National Product) and total power consumption [1]. The linear relationship postulated between GNP and kwh suggests that at least on a national level, the output of goods and services will be reduced proportionately to the total loss of electric energy. Such an approach does not take into account certain extraordinary expenses, (e.g., spoiled products, temporary relocation for safety and health, etc.). This method of evaluation does not appraise the actual sensitivity to outage costs of diverse consumers (industrial, commercial, residential), so that the application of the method to individual smaller areas of the country is questionable.

A modification of the macro-economic approach relates salaries and wages in a given geographical area to electric energy consumed by industrial and commercial customers in that area [2]. (In this approach it is assumed that labor productivity does not increase after a power interruption.) While this refinement of the economic variables affected by an outage may allow the method to be more applicable to specific geographic areas, it is recognized that the absence of residential costs may still mean a significant omission in the total evaluation.

The costs of electric power interruptions to industrial and commercial consumers have also been estimated through the use of questionnaires which elicit direct estimates of the cost of power losses for various outage levels [3-5]. As may be expected, there is a great variation in customer response, which, questions of accuracy aside, reveals the complex diversity of electric power usage. Though this method of evaluation falls short of being a measure of total societal costs, it has been developed in an attempt to optimize electrical system costs from a societal point of view. Utilities in Europe, particularly in France and Sweden have used this approach to aid in the justification for planned capacity additions [6].

It is clear that both the macro-economic and micro-economic approaches are complementary. While relating electricity usage to suitable macro-economic variables makes the evaluation of interruption cost tractable, important details in terms of exceptional and individually variable costs may be unaccounted for. On the other hand, attempting to evaluate interruption costs through analysis of individual electric customer use patterns puts reliance on the ability of customers to estimate these costs, and offers statistical problems in trying to provide meaningful averages over possibly highly varied responses. Particularly in the area of residential electric usage, which interruption costs are largely intangible, neither a

macro-or micro-economic approach by itself could probably provide a satisfactory measure of the worth of electric service quality.

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APPENDIX 8

TRANSMISSION EXPANSION BY GRADIENT SEARCH MODEL

This appendix describes a computational algorithm for automated transmission system planning that has been formulated in terms of a non-linear mathematical programming problem. A performance index of the transmission network is defined and first partial derivatives of this index with respect to network changes are computed and used to determine an appropriate set of network changes. This process is repeated until performance index minimization is achieved. Equality constraints include the set of equations defined by the linearized (dc) load flow model and the equation that implements the requirement that total system generation equals total system load (transmission losses are ignored). Inequality constraints involve upper and lower limits on transmission line admittances.

The algorithm begins with a dc load flow solution for the starting transmission network and specified future bus load and generation. Then, the system performance index is computed and circuit changes are made using the partial derivatives of the performance index with respect to circuit admittances. The type and number of circuit changes are guided by input data supplied by the user. A dc load flow solution is calculated for the network with the changes and the process is repeated. This continues until a network state is reached for which no further reduction in the performance index can be achieved.

Results available to the user include an iteration by iteration summary of the network changes that were made, a summary of network performance in terms of overloads, a final summary of network changes and installed cost of additions, and a final dc load flow solution.

In addition to the normal set of data required for a dc load flow program, the user must supply data specifying existing and future right-of-way constraints and the cost of circuit additions.

Description of the Technique

The primary steps involved in the technique are illustrated in the flowchart of Figure 1.

Note that the solution of an adjoint network is included. This solution is the key to efficiently calculating the performance index sensitivities. A mathematical description of the adjoint network is provided below, along with descriptions of the other computational steps in Figure 1.

FIGURE 1

FLOWCHART AUTOMATED PLANNING GRADIENT SEARCH ALGORITHM

DC Load Flow Model

The dc load flow model is obtained by linearizing the ac load flow equation. The assumptions involved in this linearization include:

- all bus voltage magnitudes = 1.0 p.u.
- transmission circuit resistances ignored

c. no bus to ground impedances

d. phase angle differences between buses are small so that $\sin(\theta_i - \theta_j) \approx (\theta_i - \theta_j)$

The dc load flow equations resulting from the above assumptions are given by

$$P_{NET_i} = \sum_{\substack{j=1 \\ j \neq i}}^N B_{ij} (\theta_i - \theta_j) \quad i=1,2,\dots,N \quad (1)$$

where

P_{NET_i} = the net real power injection at bus i (Generation - Load)

B_{ij} = the susceptance of the circuit connected between buses i and j

θ_i = the phase angle (wrt swing bus) of the complex voltage at bus i

N = the number of buses modelled

In the formulation given above the net injections, P_{NET_i} , are specified and the phase angles are the quantities solved. Generally, the value of the swing bus angle is designated as zero. Since the equations in (1) are linear, the method of Gaussian Elimination can be used to obtain a computer solution. Implementation of the Gaussian Elimination technique is divided into triangularization and forward elimination/back substitution. This will be discussed further in the description of the adjoint network.

The phase angles in (1) are used to calculate transmission circuit real power flows as follows:

$$P_{ij} = B_{ij} (\theta_i - \theta_j) \quad (2)$$

where

P_{ij} = the real power flow from bus i to bus j

These flows are used to compute the system performance index.

Performance Index

Formulation in terms of a non-linear mathematical programming problem involves the specification of a mathematical performance index. In the references reviewed, two different performance indices were identified. Both relate the circuit real power flow, calculated according to the dc load flow model, to the specified circuit capacity. Reference (1) utilizes a weighted error squared type index:

$$PI_a = \sum_{\ell=1}^L \frac{1}{2} W_{\ell} (P_{\ell} - P_{\ell}^{(d)})^2 \quad (3)$$

Reference (2) employs an index specified in terms of ratios and includes an installed cost factor:

$$PI_b = \sum_{\ell=1}^L \frac{1}{2n} W_{\ell} (P_{\ell}/P_{\ell}^{(d)})^{2n} + K_{\ell} B_{\ell} \quad (4)$$

The automated planning algorithms in both references minimize the respective performance indices subject to the equality constraints specified by equation (1), the condition that total system load equals total system generation:

$$\sum_{i=1}^N P_{NET_i} = 0 \quad (5)$$

and the inequality constraints

$$B_{\ell}^m \leq B_{\ell} \leq B_{\ell}^M \quad (6)$$

The terms in (3), (4), (5), and (6) are defined below:

W_{ℓ} = a real non-negative weighting function for circuit ℓ ,

P_{ℓ} = the real power flow in circuit ℓ , calculated by the dc load flow solution,

$P_{\ell}^{(d)}$ = the real power flow capacity of circuit ℓ , specified as input data,

B_{ℓ} = the susceptance of circuit ℓ ,

B_{ℓ}^m = the minimum susceptance allowed for circuit ℓ ,

B_{ℓ}^M = the maximum susceptance allowed for circuit ℓ ,

n = a positive integer, specified by the user,

K_{ℓ} = a real non-negative weighting factor which reflects the cost of line additions for circuit ℓ ,

L = the number of circuits modelled.

Note that PI_a equals zero only if all circuit flows equal circuit capacities. Lines that are lightly loaded may contribute as much to the performance index as overloaded lines. Therefore, in order to remove the effect of light circuit loading from PI_a the weighting factors W_{ℓ} are constrained so that

$$\begin{aligned} W_{\ell} &> 0 & \text{for } |P_{\ell}| > |P_{\ell}^{(d)}| \\ W_{\ell} &= 0 & \text{for } |P_{\ell}| < |P_{\ell}^{(d)}| \end{aligned} \quad \text{for all } \ell. \quad (7)$$

The second performance index, PI_b , does not exhibit this behavior since it involves a ratio of the calculated power flow to the specified power flow capacity.

The Adjoint Network

The key to the operation of the automated planning algorithm is the use of the performance index partials to decide what circuit changes are required. The adjoint network is used to calculate these partials. Derivations in both References (1) and (2) show that, when the actual power system is modelled by the dc load flow equation (1), the corresponding adjoint system can be given by

$$\hat{P}_{NET_i} = \sum_{j=1}^N \hat{B}_{ij} (\hat{\theta}_i - \hat{\theta}_j) \quad i=1,2,\dots,N \quad (8)$$

where

$$\hat{B}_{ij} = B_{ij} \quad \begin{matrix} i,j=1,2,\dots,N \\ i \neq j \end{matrix} \quad (9)$$

In equation (8) the adjoint injections are a function of the performance index; that is,

$$\hat{P}_{NET_i} = f(PI_a) \quad (10a)$$

for Reference (1), and

$$\hat{P}_{NET_i} = f'(PI_b) \quad (10b)$$

for Reference (2). In both cases, the adjoint injections can be easily calculated at the time the performance index is computed.

The adjoint angles, $\hat{\theta}_i$, in equation (8) are used to calculate the partial derivatives. The solution of equation (8) for the adjoint angles is a very efficient process, given that triangularization of the susceptance matrix has already been performed for the dc load flow solution. This adjoint solution involves only one additional forward elimination/back substitution using the adjoint injections $\hat{P}_{NET_i}$. All of the required partials can be calculated from one solution of the adjoint system since the performance index gradient vector is given by

$$V_{B^{PI}} = \begin{bmatrix} \frac{\partial PI_b}{\partial B_1} \\ \frac{\partial PI_b}{\partial B_2} \\ \vdots \\ \frac{\partial PI_b}{\partial B_L} \end{bmatrix} = \begin{bmatrix} g \left(\theta_1, \hat{\theta}_1, \frac{\partial PI}{\partial P_1} \right) + K_1 \\ g \left(\theta_2, \hat{\theta}_2, \frac{\partial PI}{\partial P_2} \right) + K_2 \\ \vdots \\ g \left(\theta_L, \hat{\theta}_L, \frac{\partial PI}{\partial P_L} \right) + K_L \end{bmatrix} \quad (11)$$

where θ 's and $\hat{\theta}$'s represent phase angle differences between the two buses terminating transmission circuits. Equation (11) represents the gradient vector for performance index PI_b ; a similar expression exists for PI_a . These expressions involve only phase angle differences between buses in the dc load flow model and adjoint system and are not dependent upon the existence of non-zero susceptances (transmission circuits) between buses. Therefore, the decision to install circuits where previously none existed can be made on an equal basis with the decision to expand existing rights-of-way.

Circuit Changes

Since circuit changes are made on an integer basis, logic is required to utilize the information supplied by the gradient vector of equation (11). References (1) and (2) employ algorithms that search along the gradient projection and compare the performance indices of feasible circuit combinations in the vicinity of this projection. The upper and lower limits on susceptances, specified by the user, are observed in this search procedure. The circuit combination that produces the smallest performance index value is chosen as the starting point for the next iteration. The network expansion is complete when no new combinations are found that further reduce the performance index.

Data Requirements

Data requirements for the automated planning program fall into two general categories; (1) typical load flow data, (2) expansion constraints. The first category includes:

1. Bus data
 - a. Bus identifiers
 - b. Generation (MW)
 - c. Load (MW)
2. Circuit data (existing)
 - a. Circuit identifiers
 - b. Circuit reactance (pu)
 - c. Circuit capacity (MW)
3. System data
 - a. Swing Bus
 - b. System MVA
 - c. Case identifiers
 - d. User specified program constants

The second category assures that the network expansion will occur within the constraints and conditions desired by the user. The items included are:

1. Circuit type data (Types of circuits to be considered in the expansion, e.g., 115kV, 345kV, etc.)
 - a. type identifiers - name and code number
 - b. type reactance/mile (pu)

- c. per mile construction costs, fixed costs
- d. type rating (MW)

2. Right-of-way data

- a. termination points - bus numbers
- b. length (miles)
- c. relative construction difficulty multiplier
- d. allowable line types
- e. minimum and maximum number of each type

Method Characteristics

The automated planning technique described above incorporates a network model (dc load flow model) that has gained general acceptance in the industry for planning applications. The performance criteria of relating calculated real power flows to power flow capacities is similar to evaluations made by planners in the early stages of expansion planning. Performance index gradients are used to make expansion decisions and therefore are a mathematical substitute for the experience and knowledge a planner would incorporate during the planning process. As a result, the expansion plans determined by the automated planning program may be different from those developed by a planner.

The specification of input data in terms of circuit types and available rights-of-way is convenient since data in this form is generally compiled for use in power system planning. The use of a gradient directed search to minimize a system performance index requires supporting logic to adapt the method to the integer nature of the problem. There is no guarantee that an absolute minimum will be found when the search terminates. In addition, it is likely that the performance indices defined in the references have local minima. However, the technique of investigating several expansion combinations along the gradient projection helps to avoid premature termination of the search.

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APPENDIX 9

TRANSMISSION EXPANSION BY LINEAR PROGRAMMING MODEL

Described in this appendix is a technique that employs linear programming and linear flow models in the formulation of an automated transmission system planning algorithm. This algorithm forms the basis of a transmission system estimation program which has been designed to produce both "horizon year" and "through-time" transmission plans.

The algorithm minimizes an objective function which is equivalent to the sum of the circuit lengths (guide numbers) times the magnitude of power which they transport. The circuit power flows are computed using a "linear loss function network model". This model approximates an electrical network model in a manner that can be employed in the linear programming formulation. Network links consist of both conventional circuits and "overload paths". The overload paths allow new load and generation buses to be factored into the network expansion without explicitly connecting them to the existing network.

The computer program can be executed in two stages -- the horizon year stage and the thru-time expansion stage. The first stage deals with obtaining the optimum network for the final year of the study. The second stage determines a step by step expansion pattern from the present network to the horizon year network. Both stages use the same optimization criteria. Thus, the thru-time optimization stage does not consider the timing of revenue outlays.

The program uses standard circuit and right-of-way data as input. The output results provide a listing of the individual circuits necessary to develop an adequate network, including the reasons for each addition as well as numbers of circuits and total mileages for each voltage level.

Description of the Technique

The automated transmission planning program employs the following basic procedure to develop a network:

1. Compute a flow estimate using linear programming to minimize the objective function while satisfying the necessary power flow requirements,
2. Select a circuit addition based on the "greatest need" of the network,
3. Repeat steps 1. and 2. until the network has no remaining shortages,
4. Once the necessary circuits have been added for the steps above, test line outages. Calculate corresponding measures

of need and add necessary circuits.

One of the salient points in the above procedure is the use of the linear flow estimation technique to optimize the network performance. The details of this process are described below.

Linear Loss Function Network Model

The linear flow estimation technique employs a linear flow model to simulate network electrical behavior. This model is comprised of nodes (buses) and network links. The links can be either conventional circuits or overload paths. The nodal quantity is defined as a guide potential; while the link parameters are power (MW), power flow capacity (MW), and guide numbers. Conventional circuits are assigned low guide numbers (proportional to circuit length) while overload paths are assigned high guide numbers (e.g., 5 X right-of-way length). The network laws governing these parameters are as follows:

- a. The magnitude of flow on conventional circuits cannot be greater than the specified circuit capacity,
- b. The magnitude of flow on overload paths is unconstrained,
- c. The summation of net power injections and net power flows at buses equals zero (Kirchoff's current law),
- d. The power flow on a link is:
 - (1) zero if the potential difference is less than the guide number;
 - (2) at capacity and in the direction from high potential to low potential, if the potential difference is greater than the guide number;
 - (3) from high to low potential and determined by the network tree when the potential difference equals the guide number,
- e. For links in the network tree the potential at the receiving end is less than the potential at the sending end by the guide number of the link,
- f. The loss function is
$$\sum_{\text{all paths}} |\text{Power Flow}| \times \text{Link Guide Number}$$

The process of linear flow estimation is employed to determine the network flow pattern that minimizes the loss function for a given network configuration. This is a linear programming algorithm and is explained in detail in the Appendix of Reference (1). The power flows computed using this technique will be different from those

computed using ac or dc load flow programs. This point will be discussed in more detail later.

One of the significant features of the estimation process is that flows can appear on overload paths as well as conventional circuits, and, as a result, these paths can be considered for circuit additions. Hence, there is no requirement that all load and/or generation buses be connected by conventional circuits.

Network Expansion

The flows determined by the linear flow estimation program are used along with a set of circuit addition rules to expand the network. The circuit addition rules, in order of preference, are as follows:

- a. Form a new circuit by looping an existing circuit into the bus to be served,
- b. Add a second circuit to an already existing tower line,
- c. Add a new circuit in an open right-of-way,
- d. Add a new circuit in a saturated right-of-way.

The program adds one circuit at a time according to the rules above. All additions of type a are made before type b additions are considered, etc.

The location for each addition is determined by a computed "measure-of-need". The measure-of-need for a circuit path equals the path overload. At each step, a flow estimation can be computed for several different system operating conditions (Normal peak, light load, specified interchange, etc.) and the measure-of-need for each path can be computed as a weighted sum over each of the conditions. Hence, the expansion may consider several network operating conditions simultaneously. The path with the largest measure-of-need is chosen for the circuit addition. A new linear flow estimate is repeated until no flows remain on overload paths.

Once this condition is attained, the program performs outage tests. Additional circuits may be added during this phase. The logic used is similar to that described above.

When the network expansion is complete, the system is generally checked using an ac load flow program. Systems studied in both References 2 and 3 indicate that the automated planning algorithm is capable of designing transmission networks that will support the required power movements. These systems also indicate that the accuracy with which the linear flow model predicts power flows may vary considerably from circuit to circuit.

Data Requirements

The following input data is required:

- a. Buses that are to be included in the study,
- b. Generation-load schedules to be served,
- c. Typical line data including voltage level, maximum number of circuits, distance-capacity relationships, emergency capacity/normal capacity ratio and circuit guide number.
- d. Rights-of-way to be considered including voltage level, initial number of circuits, maximum number of circuits, right-of-way length, and terminal buses.

Output

The primary output of the program is a list of circuit additions and the total number of circuit miles added for each circuit type. Also, rights-of-way that had measures-of-need during the expansion process, but did not receive a circuit addition, are displayed in the order of highest to lowest measure-of-need.

Method Characteristics

The automated planning technique described above employs a linear programming algorithm to determine critical locations for circuit additions. These additions are made according to a pre-specified set of rules. These are similar to considerations employed by a system planner.

The network model that is used is similar to a transportation model in that it employs Kirchoff's current law, but not Kirchoff's voltage law to define flows. As a result, the circuit flows predicted by this model may vary considerably from those predicted by an ac load flow program. In addition to conventional circuits, the flow model employs overload paths, in which power can flow if necessary. This allows the program to visualize where circuit additions are necessary.

The algorithm expands the network one circuit at a time until there are no overload paths that carry flow. After each addition a new flow estimate is computed that minimizes the accumulated products of power flow and guide number. The path with the largest overload is chosen as the location for the next addition.

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APPENDIX 10

TRANSMISSION EXPANSION BY INTEGER PROGRAMMING

Linear and non-linear programming have been applied to the single stage transmission expansion problem. The general weakness of these two approaches is the requirement that all variables be continuous. Since transmission components are added in discrete steps, some kind of round-off procedure must be used. Hence a more suitable approach is to use integer programming (IP) which recognizes the discrete nature in the transmission expansion problem.

One of the earliest reported works on the application of IP to transmission expansion was by Knight [1]. Due to the dimensionality of the problem and the poor performance of the integer programming codes available at that time, the method was viewed to be impractical. However, in recent years, more efficient IP procedures have been developed and used successfully outside the electric utility industries. Hence, there has been a renewed interest in the use of IP to develop optimal transmission expansions.

The term integer programming (IP) applies to formulations in which integer variables are present. In order to distinguish the various categories of IP, the following definitions are provided. Pure integer programming (PIP) implies that all variables are integer. In mixed-integer programming (MIP) only some of the variables are required to be integers. MIP may be divided into mixed-integer linear programming (MILP) for which all functions are linear, and mixed-integer non-linear programming (MINP) for which some functions are non-linear. In most situations, a general IP problem may be solved more easily and quickly through the use of 0-1 programming in which all integer variables take on values of either 0 or 1. Therefore, transmission expansion falls into this class of IP since each new component is either added or not added to the network.

Problem Formulation

Given the existing system, generation expansion plan and the forecast load, the problem of single-stage transmission expansion is to find a set of new lines or component additions such that various specified constraints are satisfied. In arriving at the expansion plan, it is desirable to minimize a cost function which consists of the investment and operating costs, and may also contain costs associated with environmental, legal and other requirements. The problem can be written as:

$$\text{Minimize } f(x_1, x_2, \dots, x_N)$$

Subject to

$$g_j(x_1, x_2, \dots, x_N) \geq 0, \quad j = 1, 2, \dots, M$$

$$x_i = 0 \text{ or } 1, \quad i = 1, 2, \dots, N$$

There are N new components to be considered and x_i corresponds to the decision on component i . The values of 1 and 0 mean that component i is added and not added, respectively. Cost function f will include investment costs, transmission losses and other associated costs. The set of constraint functions, g_j ($j = 1, 2, \dots, M$), is imposed by the loading on the lines under normal and/or contingency conditions. Owing to the large number of variables and constraints, and the non-linearity of the functions in transmission expansion, the computational effort necessary for solving the preceding problem is horrendous. Hence, simplifications and modifications are needed so that problems of reasonable size can be solved with existing computing facilities.

One simplification is to confine the cost and all constraint functions to be linear so that the problem becomes a MILP [2]. To do this, it is necessary to assume that line losses can be represented by precise linear functions and to use linear flow or dc load flow for the network representation. At this point there are two general approaches to take. One method begins by performing a linear program assuming that all variables x_i are continuous between 0 and 1. If all the variables x_i take on values of 0 or 1, the problem is solved. But, generally, most of the variables x_i will take on values of either 0 or 1 while the rest assume some intermediate values. A search or branch-and-bound procedure is then used to evaluate the consequences of forcing the values of these remaining variables to 0 or 1. All such possible combinations are examined either explicitly or implicitly. Standard codes on this approach are available but it is possible that feasible solutions may not be found even if they do exist.

The second method uses a combination of sensitivity and screening procedures to confine the search on a limited number of new additions which are most likely to satisfy all constraints [3, 4]. These procedures may be based on linear programming as in Reference 4 or quadratic programming as in Reference 3. In the latter case the problem becomes one of MINP. Ineffective components are eliminated thereby reducing the number of variables and thus the computing effort. The resulting problem is then solved by a branch-and-bound procedure. This process is repeated until all constraints are satisfied. Figure 1 shows a simplified flowchart of the method.

Figure 2 shows the decision graph or tree for a branch-and-bound procedure. Each stage or level represents the status of an element. Thus each node corresponds to a state of the network. The

FIGURE 1

SIMPLIFIED FLOWCHART FOR A MIP APPROACH TO TRANSMISSION EXPANSION

process begins from the initial node and branches off to the next level. The procedure is as follows:

1. Set an upper bound on the cost $f(x) = F$.
2. Branch-off to the next level, if possible; otherwise go to step 5.
3. Compute the cost for the new node. If cost is greater than F , go to step 5; otherwise continue.
4. Cost is less than F ; if constraints are not completely satisfied, go to step 2. If constraints are satisfied, a better solution has been found. Store the solution and set F to the new cost.
5. If possible go back to the previous level and go to step 2. Otherwise terminate the process as soon as the search is complete. The optimal solution, if it exists, is the one which is in storage.

FIGURE 2

DECISION TREE FOR REPRESENTATION OF EACH COMPONENT

The search or procedure will terminate after no more than 2^N steps. However, with the truncation or bounding on the branches, the number of steps actually executed will be a fraction of 2^N . By ordering the variables or search in a certain way, the number of executed steps can be further reduced.

Computational requirements can be reduced through the use of optimal cost-capacity curves for each right-of-way rather than identifying each individual line or element [4]. For each value of permissible capacity, the combination of lines which results in the minimum cost is determined. Figure 3 shows an example of the cost-capacity curve. With this representation, the levels in the decision graph correspond to individual rights-of-way so that the number of branches from a node is not necessarily equal to two, but rather is equal to one plus the number of capacity steps for the corresponding right-of-way. An example of the decision tree for this approach is given in Figure 4 in which each stage or level corresponds to one right-of-way. To assure that no more than one capacity step is represented at any time, the following additional constraint is introduced for each right-of-way:

$$\sum_{j=1}^{n(i)} x_{ij} \leq 1$$

where

x_{ij} is the j 'th capacity step for the i 'th right-of-way,

$x_{ij} = 0$ or 1 , $j = 1, 2, \dots, n(i)$,

$n(i)$ = no. of capacity steps for the i 'th right-of-way.

To demonstrate the reduction in the computational effect, suppose there are 5 rights-of-way and each right-of-way may have up to 4 identical lines. Thus there are altogether 20 possible new elements. In the first formulation, the total number of possible combinations is 2^{20} or about 1,000,000. But when capacity-cost curves are used, there will be only 5 different capacity steps for each right-of-way, and the total number of possible combinations is only 5^4 or 625.

Data Requirements

There are two general categories of data to be used, namely: (1) typical load flow data and (2) expansion data. The type of load flow data will depend on the representation of the network as a linear flow, d.c. load flow, or a.c. load flow model. Expansion data include constraints and particulars on new components such as locations, investment costs and capacities. Interest and inflation rates may be added for time-phased expansions.

Characteristics

Single-stage transmission expansion can be formulated as a MIP problem for which the optimal plan can be determined if it exists. Due to the large number and the complexity of the imposed constraints, it is not practical to solve the problem directly, that is, to consider the whole

FIGURE 3

COST-CAPACITY CURVE FOR A RIGHT-OF-WAY

FIGURE 4

DECISION TREE FOR A COST-CAPACITY REPRESENTATION

solution state space at one time. However, reasonable approaches based on repeated solving for the optimal solution in relatively small sub-spaces have been proposed. These sub-spaces are established through certain screening and sensitivity procedures.

Computational effort is unpredictable and depends on a number of factors which include:

- o Screening and sensitivity procedures for confining the search within a sub-space.
- o Ordering of the sequence of search.

This method would normally find the optimal solution if it exists. Other non-optimal but feasible solutions may be obtained if the first feasible solution encountered is not the optimal one. But in general, other sub-optimal solutions could have been bypassed. In transmission expansion, for which there are many constraints which cannot be quantified, it is more desirable to obtain a number of different sub-optimal expansions rather than just the optimal one. Fortunately, a number of sub-optimal expansions, including the optimal one, can be obtained by relaxing the truncating or bounding criterion to the latest lowest cost, F , plus an increment F . Thus, all expansions having costs within F of the optimal plan will be determined. But this procedure could increase the computational effort considerably.

In general, computational effort increases rapidly with problem size. Reported studies on systems with about 60 buses, 120 lines and 20 rights-of-way, have shown that computational efforts appear to be reasonable. Nevertheless, further tests are needed on larger systems.

To the authors' knowledge, there is as yet no reported effort to consider uncertainties in the available generation and load.

It may be pointed out that new generating capacities are added in discrete steps and the locations of generating plants do influence the transmission network. Therefore it may be desirable to treat generation and transmission expansions simultaneously. Reference 5 describes such a treatment wherein MILP is used to determine the optimal generation and transmission expansion plan. The inclusion of generation alternatives in transmission expansion obviously increases the size of the problem.

Optimal single-stage transmission expansion is a static mathematical programming problem. Although this approach is widely accepted and used in the electric utility industries, it has the tendency to add many smaller lines when the time periods are small and install larger lines if the horizon year is far out into the future. Since the installation of a line does influence future system operation and the accumulated cost, it is essential to evaluate the cost for an expansion which identifies the timing for the installation of new elements through the time period. This

calculation will allow the inclusion of inflation and interest rates in the comparison of different expansion plans. Such features are available in the time-phased approach to transmission expansion.

Extension to Time-Phased Expansion

Work has been done on the application of IP to time-phased transmission expansion in which the time period is divided into a number of sub-periods. The loads and generating capabilities for all the sub-periods are given. The problem is to determine the capacity, location and timing of new lines such that all constraints are satisfied plus minimizing a cost function.

One approach is to define a set of conditions for each sub-period and formulate the expansion as one large static problem as follows [2]:

$$\text{Minimize} \quad \sum_{t=1}^T f_t(x_{1t}, x_{2t}, \dots, x_{Nt})$$

Subject to

$$g_{jt}(x_{1t}, x_{2t}, \dots, x_{Nt}) \geq 0, \quad j = 1, 2, \dots, M_t, \\ t = 1, 2, \dots, T,$$

$$\sum_{t=1}^T x_{it} \leq 1, \quad i = 1, 2, \dots, N,$$

$$x_{it} = 0 \text{ or } 1$$

where

t denotes the sub-period,

x_{it} equals 1 denotes that component i is added at time t , equals 0 otherwise.

The new constraint for each component is to assure that the component is added no more than once during the planning period. Interest and inflation rates can be easily included in the cost functions. The size of the problem increases very rapidly with system size and the number of sub-periods. This method has yet to be successfully applied to reasonably large systems.

Reference 6 presents a novel alternate approach which is computationally more efficient, particularly when the network is represented by a linear flow network (It is misleading to have labeled this method as "dynamic programming" when it is, in fact, an integer programming method.) However, d.c. load flow can be used instead, but this will increase the computational effort. In the linear flow network, the minimal cut can be determined very quickly. The minimal cut defines the maximal transfer capability from the generating

FIGURE 5

EXAMPLE OF DECISION GRAPH

facilities to all the loads. This maximal transfer can only be increased by increasing the capacity of the minimal cut and thus a small set of effective new components are identified [7]. At each stage only a limited number of possibilities need to be examined. A branch-and-bound technique is used to obtain the optimal plus other sub-optimal plans if desired. Figure 5 shows the decision graph in which each stage corresponds to the addition of one new component. Associated with each node is a time label which indicates the latest sub-period for which the loads or constraints are satisfied. In this particular approach, the decision graph is not necessarily a tree since each node represents a network state which can be reached via different sequences of installation. Nodes are terminated when costs are greater than the value of the bounding criterion which is normally equal to the lowest cost for the feasible solutions encountered. Again, this approach has yet to be tested on reasonably large systems.

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APPENDIX 11

THROUGH-TIME OPTIMIZATION

Introduction

The transmission expansion problem consists of choosing one or more expansion plans such that over the planning period, all loads and constraints are satisfied. Generally constraints are related to the operation of the network and they may include various environmental and legal requirements. Since the installation of a line at one time instant does directly influence other installations and operating costs into the future, it is important that this propagating effect be observed in the selection of final expansion plans. Through-time or time-phased optimization methods include such time-related effects.

Addition of line capacities are performed in discrete steps only. As a consequence, continuous optimization techniques require some kind of round-off procedure, and therefore expansion plans obtained by such methods could be far from optimal. This does not necessarily rule out the applications of continuous optimization methods as there are many other factors involved in the choice of suitable methods for transmission expansion purposes. Round-off can be eliminated through the use of discrete optimization techniques such as integer and dynamic programming.

The use of integer programming for time-phased transmission expansion is presented in Appendix 10 and will not be discussed further herein. This appendix will focus on the dynamic programming (DP) approach [1] which appears to be suitable because all variables are not required to be continuous and all cost and constraint functions could be nonlinear. DP has been used extensively to determine optimal solutions for a variety of multi-stage decision problems, such as time-phased transmission expansion.

Problem Formulation

The planning horizon or period is divided into a number of timesteps with specified loads and available generation. The sequence of transmission line additions must be determined such that constraints at every timestep or stage are satisfied. For long range transmission expansion, each stage may correspond to one or more years. A sequence of line additions corresponds to an expansion plan and a feasible expansion is one for which all constraints are satisfied. The problem is to find the optimal expansion and, if possible, a set of near optimal expansions also.

Figure 1 illustrates the steps in the use of DP for transmission expansion. For each stage or year, a set of network configurations or states is generated. Only feasible states, that is, those satisfying all specified constraints, will be kept while all infeasible states are rejected. In this

feasibility check, the network could be represented by the more accurate ac load flow model or the simpler dc load flow model. The operating cost, if any, for each state is then computed. A sequence of states, one at each stage, represents an expansion plan. The problem is to find the sequence with the minimum cost. Thus, the transmission expansion problem becomes a multi-stage decision problem.

FIGURE 1

APPLICATION OF DYNAMIC PROGRAMMING TO TRANSMISSION EXPANSION

Given the specified set of system states for each stage, DP is an efficient method for finding the optimal expansion. The efficiency rests on the fact that the expansion process is Markovian; that is, given a specific state at some stage, the optimal solution depends only on the condition of the state and does not depend on how the state was reached. DP computation could proceed in either forward or reverse direction. Below, the forward DP is examined, although the reverse DP is just as applicable. The well-known recursive equation in DP is given by

$$f(x_i, t) = \min_j \{ f(x_j, t-1) + C(x_i, t) + D(x_j, x_i) \}$$

where

$f(x_i, t)$ = a least cumulative cost to state x_i at stage t ,

$C(x_i, t)$ = total operating cost for state x_i at stage t ,

$D(x_j, x_i)$ = transitional cost from state x_j at stage $t-1$ to state x_i at stage t .

The minimization on the right-hand side is carried out over all states at the previous stage. It can be seen that the computation progresses one stage at a time and the least cumulative cost can be determined from the costs for the previous stage. Figure 2 shows a flowchart of the procedure and a simple example of the decision graph for a 5-stage process is given in Figure 3. The inner loop in Figure 2 corresponds to the minimization process for state x_i at stage t , the middle loop is for each state at stage t and the outer loop is for each stage.

The transition from state $x_j(t-1)$ to state $x_i(t)$ should be permissible in that the set of new lines for $x_j(t-1)$ must not be in excess of those for $x_i(t)$. Any new lines required to achieve this transition can be identified and the transitional cost will be the discounted cost for these new lines.

Only permissible transitions are shown on the decision graph in Figure 3. For example, only one transition is permissible from state 4 at stage 2 to the states at stage 3, state 3 in particular. Transitions to the other two states are not permissible. A sequence of transitions from the initial state to any of the four states at the last stage corresponds to an expansion plan. In this particular example, there are altogether $3 \times 4 \times 3 \times 3 \times 4 = 432$ possible expansion plans but only 80 of these are permissible. The bold lines in Figure 3 indicate the optimal transitions for each state. Now suppose the least cumulative cost to the last stage is at state 3; then tracing back on the optimal transitions, the optimal expansion plan is (2,4,3,3,3) where the i 'th entry gives the state for stage i .

Data Requirements

There are two general categories of data to be used: (1) typical load flow data, and (2) expansion data. The type of load flow data will depend on the representation of the network as linear flow, dc load flow or ac load flow model. Expansion data include constraints and particulars on new components such as locations, investment costs and capacities. Interest and inflation rates may be added for this time-phased expansion.

Characteristics

DP is a suitable approach for transmission expansion problems in that optimal and near optimal expansion plans can be determined, and approximations can be kept to a minimum. In general,

FIGURE 2

FLOWCHART ON THE DYNAMIC PROGRAMMING PROCEDURE

many possible line additions are available at each stage, so that transmission expansion becomes a highly combinational problem. The high dimensionality of this problem imposes excessive computational effort in the use of DP for transmission expansion purposes. Therefore, in all reported studies, limitations are placed on the number of alternatives or states so that the expansion problem is computationally manageable.

One approach to limit the number of alternatives is the use of linear programming to find lower bounds for various line capacity additions [2]. These bounds are established through sensitivity measures based on the linear power-flow model of the network, and linear-cost functions for the new line capacities. DP is then used to find the optimal expansion plan.

FIGURE 3

EXAMPLE OF A DECISION GRAPH IN DYNAMIC PROGRAMMING

(Bold lines indicate Optimal Transitions)

Another approach, termed discrete dynamic optimization (DDO), uses a combination of DP, a random search and a heuristic stopping criterion [3]. The procedure chooses an expansion plan at random from a set of specified components or alternatives. A neighborhood or a small region around the chosen plan is then generated and DP is used to determine the optimal expansion from this set of limited possibilities. This procedure is repeated until a stopping rule is satisfied. The stopping rule is based on a heuristic criterion which terminates the process whenever the expected improvement in the cost function is less than some specified value. In a sense, this DDO method is a generalization of the Monte Carlo method coupled with the use of DP. To assure that computational effort is manageable, linear power-flow is used to model the network. It may be pointed out that the authors defined the cost or objective function in terms of the decisions or alternatives, instead of system states. In this case, the expansion problem as formulated is not a Markovian process and thus the solution obtained is not necessarily optimal.

The use of DP has also been applied to determine the least expected cost expansion when uncertainty is present in the load profile [4]. Again to limit the size of the problem, the number of system states must be small. The objective function is the expected value of the sum of investment, operating and penalty costs. The penalty cost is some measure of the reliability of the network and could be defined in terms of the expected load loss. It is possible to include uncertainty on other study parameters, such as investment cost and installation load times of equipment. Though the treatment of uncertainties in transmission expansion is desirable, it does increase the dimensionality of the problem tremendously. Also, in the presence of uncertainty, it may be more strategic to derive expansion

sions which are more flexible and less sensitive to cost changes rather than the least expected cost expansion. However, such considerations would further complicate the stochastic DP approach to transmission expansion.

The method given in Reference 5 has been mislabeled as "dynamic programming" when in fact it is an integer programming approach. A discussion on this method is given in the appendix on the integer programming approach.

A technique known as the "k-shortest paths" has been used in place of DP for transmission expansion [6]. This method is used both to generate a limited number of system configurations at each expansion stage and to find a number of least cost expansion plans. For the first purpose, the network is represented by a flow-network with the initial flows established by a load flow and a limited number of rights-of-way which have the potential of releasing overloads are determined. Based on these rights-of-way, various possible combinations of network configurations are then generated and only those which satisfy all constraints are retained. Thus a number of feasible system states are established for each stage and a decision graph similar to that shown in Figure 3 is formed. Corresponding to each arc or transition is the cost associated with the investment of new lines and to each node is the operating cost. From this decision graph, the "k-shortest paths" method [7], which is based on the Ford and Fulkerson flow technique [8] is used to find the expansion plans with the lowest costs.

In general, only small systems have been tested using the DP and "k-shortest paths" though the formulations are not limited by system size. Computational requirement is the major obstacle to the application of these methods to transmission expansion.

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HEURISTIC PLANNING MODELS

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A succinct statement of the problem has been provided by Meckiff, Boardman, Richards, and Green [6]:

During the past twenty years or so a great deal of effort has gone into applications of the digital computer to the design and analysis of electricity supply networks. The reasons for this are plain. Firstly, the financial investment in the electricity supply industry is so great that even small modifications in a network design, or minor changes in operating procedures could produce very significant cost savings to the industry. Secondly, the problems encountered in network design are enormously complex, but reasonably well-defined, and thus present an irresistible challenge to the planning engineer conscious of the power of modern computer systems.

Originally, use of the computer came in the area of analysis, with the construction of programs to simulate load flows, fault flows and transient characteristics. In this, the network analyser and hand-computation were rapidly superseded. Computers are now accepted as being an indispensable tool in network performance analysis. A similar trend has been taking place, in much less spectacular fashion, by the application of computer methods to network synthesis and expansion studies. The general philosophy is to enable the computer to participate to a greater extent in the decision making process.

These authors continue:

Since the beginning of synthesis expansion studies, one area in particular has demanded greatest attention, viz., precise problem formulation. The large number of constraints posed by the synthesis problem has meant that in the mathematical solution methods, the majority of documented work has been concerned with the formulation and rationalisation of constraints, and actual mathematical optimisation has simply involved calling upon known methods such as linear and dynamic programming, and branch and bound.

And continuing:

Heuristic methods have received less attention than mathematical ones. Burstall [8] attempted a green-field heuristic synthesis method, ending up with a rather gross network improvement program with unreasonable computing times for realistic sized networks. Garver [9] used a heuristic estimation method for suggesting network reinforcements.

Finally, a statement of their position on problem formulation and heuristic philosophy:

It is somewhat surprising that so much effort has been given to devising mathematical methods for network design, but only a relatively small amount of effort has been devoted to heuristic methods. It is inevitable in a problem of such complexity that approximations must be made in the problem formulation. Many constraints which occur in real-life situations cannot be specified in absolute terms, e.g. considerations such as aesthetic appeal and acceptability to conservationists are unquantifiable. Therefore, any mathematically produced result can rarely claim to be a true global optimum. Any network design, suggested by whatever means, must come under close scrutiny after the computer has performed its function in order to assess its acceptability.

Meckiff, et al., continue with a comparison of 5 different heuristic methods for network synthesis.

The essential components of an automatic heuristic planning procedure would include:

1. Load Model

The models include procedures for forecasting loads by types (residential, commercial, industrial) for characteristic daily and seasonal shapes and by planning subdivision. The term "Basic Load Area" has been used by some to describe geographical areas of resolution sufficient to permit service to be provided by a single network element [5,7].

2. Network Models

Network models are provided for assessing facilities loading under normal and usually fixed contingency conditions. The models have ranged from ac network representations [1-5,7] to linear power flow models [9]. Fault current checks were provided in certain of the models [6] and loss and voltage (drop) checks in others [3,4,7]. Here, one need note that certain of the models such as Garver's linear power flow model [9] were shaped around bulk power transmission planning procedures for areas of relatively high load density and short transmission distances. For problems of this type it is reasonable to use a linear power model together with circuit thermal ratings to develop a plan of circuit additions and then to plan for var additions to control voltage. The cost disparity separating circuits and capacitors provides a logical economic hierarchy in this instance. The condition is analogous to the traditional cost disparity between generation and transmission. As a result, generation additions have been selected on the primary bases of site availability and expansion costs. Transmission plans were then prepared for each specific generation expansion plan at the most, or, in many cases, just for the "optimum" generation expansion plan.

3. Synthesis Methods

This is the task that separates the heuristic and "mathematical program" schools. Meckiff, et al., stated the distinction very well in their "heuristic philosophy" quoted previously:

Heuristic Approach

- i Simple models and logic
- ii Families of "feasible-near optimal" plans
- iii User interaction

Mathematical Program Approach

- i Model fixed by program formulation
- ii Detailed logic or constraint set definition
- iii Single "global" answer usually provided
- iv No user interaction

Two points need to be noted regarding transmission planning procedures: First, the problem formula must ultimately lead to integer form; circuits, substations, voltage levels, etc., are all discrete. Second, it is useful to separate the essentially radial (distribution and subtransmission) problem formulations such as described in References 5 and 7 from the multiply interconnected (transmission) problem formulations as, for instance, in References 1 and 9.

References 1 and 7 provide an interesting contrast in synthesis methods. A logical "fencing" method was utilized in Reference 1 to disclose reinforcement requirements. The "fence" was a closed boundary used to check transfers under contingency conditions. A linear program formulation was used in Reference 9 to disclose reinforcement requirements. "High cost" "overload paths" were permitted to carry the unserved transfers. Single circuit additions were selected from the most cost effective to displace "overload path" flows.

Examples of automatic logical programs are offered in Figure 1 which appears in Reference 4 and Figure 2 which was taken from Reference 3. Both programs emulate the manual planning procedure but do not provide for user interaction. It appears that neither has endured as a planning tool. The relief procedures of Reference 3 appear in Figure 3 for low voltage and Figure 4 for overload. These two figures serve well to highlight the complexities of mathematical formulations of the constraints, alternatives, and objectives of "cost functions".

4. Display Facilities

It seems appropriate to close this discussion with a quote from Meckiff, et al., which, again, states very well the needs for effective means for user-program communication.

It has been found to be very important, if not essential, to use interactive graphics in the development and use of the algorithms described in this paper. Each algorithm attempts to produce network configurations

FIGURE 1

OPERATION FLOWCHART OF AN AUTOMATIC TRANSMISSION PLANNING PROGRAM

FIGURE 2

FLOW DIAGRAM OF THE TRANSMISSION PLANNING PROGRAM

Legend:

NP - Not Possible
LV Bus - Bus with Unacceptable Voltage
TP Bus - Terminal Priority Bus
HV - High Voltage
M/H - Line designed for High Voltage but temporarily operating at Medium Voltage

FIGURE 3

THE LOW VOLTAGE LOGIC

Legend:

NP - Not Possible
U - Unsuccessful
OL Line - Overloaded Line

NOTE: In case of an overloaded transformer, another transformer is added to operate in parallel.

FIGURE 4

THE OVERLOAD LOGIC

which, although they are not claimed to be global optima, are local optima. In a problem such as the one described, where synthesis proceeds on a step-by-step basis, each step offering a variety of courses to follow thereafter, a problem of reasonable size, say 100 busbars, with even a fairly small number of alternatives at each stage, has an enormous solution tree. Each end point in the tree is a local optimum, and one or more of the end-points will be the global optimum within the definition of the problem. (There may be more than one since the global optimum could be reached via different branches of the tree). As previously stated, a design could be produced which is a global optimum within the constraint definition but which will be rejected due to violation of some constraints which are not quantifiable. If this happens, then it is required to investigate the local optima whose configurations are such that the objective function has a value acceptably close to that of the global optimum. In the heuristic synthesis problem tackled in this paper, it is impossible to know whether a design is a global optimum, even within the constraint definitions used, but it is possible to investigate very effectively the local optima in the region of the (unknown) global optimum, provided that branchings at each stage of the synthesis process are varied.

In running the programs there are two options available for the execution of the synthesis algorithms. Firstly, the computer may automatically select the best circuit addition or exchange at each stage. Within the realms of this problem "best" means the most economically effective. Alternatively the designer may be given a choice of circuit additions or changes whereby he may direct the synthesis process along whichever branches of the solution tree he desires. Thus, families of near global-optimum designs can easily be produced ready for final testing and approval.

Graphical displays have been found to be useful since in order to direct the synthesis process effectively it is useful to know what stage the operation has so far reached. An up-to-date graphical display of a network at each stage of development helps the designer to identify the more useful circuit changes, and in his choice of the next step, he effectively overrides the computer program which is a rigid interpretation of what in retrospect must seem to be an inadequate representation of the optimal route.

Such an interactive process appears most likely to overcome the inherent limitations of the "canned" logical approaches in which the sensitivity of results to small changes in data tend, at times, to cause great or "watershed" type changes

in plans. This problem is discussed by Eichenberger and Fine [5] who cited the sensitivity of logical methods to small changes in sub-transmission cost data. While supporting the worth of planning aids such as simulation programs Reference 5 cautions that the most important requirement is accurate data and the most crucial data requirements are accurate small area load forecasts.

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APPENDICES
OF
Systems Control, Inc.

APPENDIX (A)

THE BROOKHAVEN ENERGY SYSTEM MODELS*

PURPOSE AND SCOPE

Brookhaven National Laboratories (BNL) has developed a set of models of the U.S. energy system. The purpose of these models is to provide a consistent framework for studying the nation's energy system. The models are intended to address such issues as: the implications of resource limitation, the potential of new energy production technologies, the impacts of new energy end-use technologies, the environmental impacts associated with the conversion of energy from resources to end-uses, and the analysis of national energy policy options.

Two basic types of model are used to describe the U.S. energy system; an Energy System Network Simulator (ESNS) and a group of energy system optimization models. ESNS evaluates the energy flow through the network, given the final energy demands, process efficiencies, and market shares. The optimization models are Linear Programs (LP), which minimize the cost of energy consumption, subject to supply, demand and process constraints. There are three optimization models: BESOM, which is static and treats the entire U.S. as a single region; DESOM, which extends BESOM over time; and RESOM, a static, regionalized version currently under development. This discussion is limited to BESOM and DESOM. A schematic representation of the energy system network which serves as a basis for BESOM and DESOM is shown in Figure A.1.

GENERAL DISCUSSION OF BESOM

BESOM is formulated as a classical LP transportation problem. The supply side is viewed as a set of n independent processes which can (in principle) meet any of m demands for energy. The matrix of supply and demand categories used in BESOM is shown in Figure A.2. In practice, most of the combinations are not used; many are not technically feasible and others are constrained to zero except for specific studies.

The objective of the program is to choose energy levels for the processes such that the cost of meeting all energy demands is minimized, subject to constraints on the basic fuel supplies and conversion processes. Mathematically, the problem is formulated as a linear programming problem which may be stated as follows:

$$\min J = \sum_{i,j} C_{ij} X_{ij} \quad (A.1)$$

Subject to:

(Energy balance equations)

$$\frac{1}{e_{ij}} X_{ij} - s_i = 0, \quad i=1, \dots, n$$

(Supply process constraints)

$$s_i \leq S_i, \quad i=1, \dots, n$$

(Fuel supply constraints)

$$\sum_{i \in I(\ell)} s_i \leq Q, \quad \ell=1, \dots, L$$

(Energy demand equations)

$$\sum_i d_{ij} X_{ij} = D_j, \quad j=1, \dots, m$$

(Other constraints)

$$\sum_{i,j} f_{ijk} X_{ij} \leq b_k, \quad k=1, \dots, K$$

$$X_{ij} \geq 0, \text{ for all } i,j's$$

*This description is based upon a series of reports published by the Department of Applied Science, Brookhaven National Laboratory, other reports by the model's developers, and the author's personal experience with the model. Specific references are not given in the text since their number would have been excessive. The list of references consulted is given at the end of this appendix.

Figure A.1 Schematic Representation of BESOM's Energy Network

Figure A.2 BESOM Variable

where X_{ij} = units of energy (intermediate form) supplied by source i to demand j .
(quad = 10^{15} Btu)

C_{ij} = unit cost of process ij (\$/MBtu = B\$/quad)

e_{ij} = supply side efficiency of process ij

d_{ij} = demand side efficiency of process ij

f_{ijk} = constraint coefficient for process ij and constraint k

s_i = energy supplied by process i (quad)

S_i = upper bound on energy supplied by process i (quad)

Q_z = upper bound on fuel supply (quad)

$I(z)$ = set of processes that use basic fuel

D_j = j^{th} energy demand (quad)

b_k = k^{th} constraint (appropriate units)

BESOM Variables

The variables of BESOM are intermediate energy used annually for each valid combination of supply and demand. Intermediate energy is defined as the energy flow at some arbitrary intermediate point between supply and demand. Intermediate energies are related to energy supplies by supply-side efficiencies and are related to energy demand by demand-side efficiencies. Any convenient point along the energy flow can be selected as the intermediate point. For example, in all processes using electric energy, intermediate energy is designated as delivered electric energy, that is, "at the wall plug".

Cost Coefficients

Each cost coefficient reflects the capital, operation and maintenance, and fuel costs associated with that particular energy supply path. The capital costs are annualized on the basis of a fixed capital recovery factor. All costs are expressed in units of 1974 dollars per MBTU of energy. The total cost coefficients used in the program are pre-calculated from equations of the form:

$$C_E = (C_F/UF) + C_V \quad (A.2.)$$

where:

C_F = Annualized capital cost per unit of capacity

C_V = Variable cost per unit of energy

UF = Utilization factor, the fraction of the year that the generation unit is actually used

Capital cost includes components for generation, transmission, and distribution. Variable costs include fuel costs and operation and maintenance costs.

Constraint Relations

There are several different types of constraint relations used in BESOM. Each is described briefly below.

The supply process constraints combined with the energy balance equations bound each individual supply technology. Each supply path represents a technology process chain which includes activities such as fuel extraction, fuel transportation, fuel conversion and energy transmission or distribution. For example, the technological processes associated with the coal-fired steam supply category of the electric utility sector include coal extraction and cleaning, the transport of coal to the plant, coal steam electric generation and transmission of electricity. These elements are not represented individually in the program, however. There, all of these processes are represented by a single total supply efficiency e_{ij} .

The fuel supply constraints limit the basic fossil fuels used by the supply technologies. These constraints ensure that the total amount of a basic fuel used by several different processes does not exceed the quantity of that fuel that is available.

The demand constraints specify the end-use energy demands that must be satisfied by the supply processes. Note that they are equality constraints, that is, the demands must be met exactly. As stated above, the intermediate energy is related to the final use energy demand by a single demand-side efficiency d_{ij} . The demand-side efficiency incorporates the efficiencies, to each process as appropriate, that lie between the intermediate energy form and the final use.

The "other" constraints include electric power off-peak constraints, energy conversion limitations, environmental constraints and new technology limitations.

The electric power off-peak constraints define the electric power that is available for off-peak uses on both a seasonal and a weekly basis. The weekly off-peak equations ensure that the energy consumed for peak and off-peak uses does not exceed the total available energy. The seasonal off-peak equations ensure that the electric power capacity available during the peak season (may be either winter or summer, depending upon how the constraint is chosen) is

	c_{10}
	BESOM VARIABLES AT t_{10}

Figure A.3 Structural Relationship of DESOM to BESOM

greater than the required capacity in the off-peak season.

The energy conversion limitation constraints are imposed to prevent allocations that violate physical or societal conditions not explicitly modeled. For example, a lower bound is applied to electricity-to-space heat energy. Without this bound, electric energy would not be used for space heat because it is uneconomical on a national average basis.

The environmental constraints limit the total amount of pollutants (e.g., sulfur dioxide) that can be released in meeting the energy demands. Environmental coefficients specifying quantity of pollutant per quad of intermediate energy are used in these equations and must be specified exogenously.

The new technology limitations constrain the availability of new technology equipment, such as the electric automobile, for the reference year.

Extension Over Time

DESOM is an extension of BESOM over the time domain. There are ten planning periods of equal length; five years in the version studied. DESOM determines the set of energy supplies that minimize the total discounted cost of meeting the exogenously specified demands for each period, subject to intra- and inter-period constraints on the basic fuels and the supply processes. The structural relationship between BESOM and DESOM is shown in Figure A.3. There are three types of constraint relations employed; intra-period constraints, inter-period constraints and multi-period constraints. The intra-period constraints are essentially equivalent to the constraints used in BESOM. The inter-period constraints control period-to-period growth in resource extraction and capacity. Multi-period constraints are applied to total resource extraction. Current versions of DESOM contain about 1400 variables and 1200 constraint equations.

ELECTRIC ENERGY SUBMODEL

Strictly speaking, there is no electric submodel of BESOM; the electric energy generating technologies are energy supplies not essentially different in their parametric definition from other energy supplies. However, there are particular features of the model which deal with the supply of and demand for electric energy. These features are described below.

Electric Load Model

Each component of demand that can be satisfied at least partially by electric energy is characterized by three parameters: the energy required, D_j ; the fraction of the year that the demand exists, L_j ; and a parameter, g_j , which specifies the portion of the energy that must

be considered to be peak demand. To clarify this concept, consider Figure A.4; the load duration curve for the j^{th} demand is approximated by the two blocks of energy, $(E_p)_j$ and $(E_b)_j$. The primary component of the annual demand is $(E_b)_j$ which has a duration L_j . The secondary, or peak, component of the annual demand is $(E_p)_j$ which has a duration of L_p . The "g" factor is defined by Equation (A.e):

$$g_j = (E_p)_j / (E_b)_j \quad (\text{A.3})$$

Let X_j be the portion of the j^{th} demand satisfied by electricity.

Then a quantity of electric energy

$$E_j = X_j / (1 + g_j) \quad (\text{A.4})$$

must be supplied at load duration L_j .

Each electric load has its characteristic load duration factor, L_j , however, the secondary load duration factor, $L_p = 0.1$ is the same for any of the demand categories that has a peak component ($g_j \neq 0$). The total of these secondary electric loads with load duration factor, L_p , is identified as the peak component of the electric load, that is:

$$x_p = \sum_j (E_p)_j \quad (\text{A.5})$$

or, substituting for $(E_p)_j$ from Equation (A.3):

$$x_p = \sum_j X_j g_j / (1 + g_j) \quad (\text{A.6})$$

In the various descriptions of BESOM, Equation (A-6) is called the endogenous peak constraint equation, since the peak demand is not specified exogenously but is, instead, determined endogenously from Equation (A.6).

Note that the shape of the electric energy component of each demand is determined by the parameters g_j , L_j , and L_p . The total demand, D_j , is specified exogenously, but the electric energy component X_j is determined by the program. Figure A.5 shows how the total electric load is built up out of the components. This figure is illustrative only; the components are never actually aggregated in the program.

The demand category called "miscellaneous electric" accounts for the majority (approximately 70 percent of the total) of the demand for electric energy. In order to more accurately

Figure A.4 Load Duration Curve Representation

represent this important category, the demand was decomposed into two exogenous demands; miscellaneous base load and miscellaneous intermediate load. Each of these components also has a "peak" portion, thus, the miscellaneous electric energy demand is divided into three components; base, intermediate and peak demand.

The demands, storage, heat pump, space heat, and water heat have no load duration factors associated with them. They are classified as off-peak uses which do not require any addition of capacity. Therefore, these uses have no capital cost component included in their cost coefficients. Air conditioning may be substituted for space heat to switch from a summer peaking to a winter peaking condition.

Generation Processes in BESOM

There are twelve central electric energy generation technologies defined in BESOM, plus pumped hydro storage. In addition, there are several decentralized technologies represented. Table A.1 lists the technologies modeled and the basic fuel associated with each.

The central generation processes are generally straightforward. Each is characterized by a single efficiency and a cost coefficient corresponding to each end use that can be supplied by the process. Pumped hydro appears both as a demand category and a supply category. This device allows spare base-load capacity to be converted to stored hydro (or hydrogen) which then may be used to meet peak or intermediate loads.

The decentralized generation technologies are solar cells, fuel cells, and total energy systems. Fuel cells and total energy systems may be fueled by any of the fossil fuels except coal, as well as coal that has been converted to oil, synthetic natural gas, methane, or methanol. Also, hydrogen from coal or electrolysis (supplied by electric storage) may be used to supply fuel cells. Again, each process is characterized by an efficiency and a cost coefficient.

Electric Storage

All electricity supplied to electric storage must be generated by spare capacity. For example, given the load shapes shown in Figure A.6, the shaded areas are the energy available for storage in the models. Each segment of the load duration curve is associated with a particular load duration factor, L_i .

Whenever $L_i < PF$ (PF = plant factor), spare capacity can be used to satisfy off-peak demands, including storage.

The energy delivered to electric storage demand is used as energy for the pumped storage and hydrogen from electrolysis supply categories. The actual electric storage demand is determined

endogenously through an energy balance constraint:

$$\left(\begin{array}{c} \text{Electric Storage} \\ \text{Energy} \end{array} \right) = \left(\begin{array}{c} \text{Energy Delivered by} \\ \text{H}_2 \text{ from Electrolysis} \end{array} \right) + \left(\begin{array}{c} \text{Energy Delivered} \\ \text{by Pumped Storage} \end{array} \right)$$

Supply limits for the hydrogen from electrolysis and the pumped storage supply categories are specified exogenously. However, the actual energy delivered by each category in a scenario depends on its cost relative to other supply categories. Because electric storage is an off-peak demand, the costs associated with supplying energy to electric storage do not include capital costs; the costs include only operation, maintenance and fuel costs.

Reserve Margin

Reserve capacity is not directly considered in BESOM and DESOM. In each program, a generation plant factor is specified (usually 0.8) to represent maximum yearly uptime, taking into account downtime for outages and maintenance. The capacities determined by BESOM and DESOM are designed to meet electric demands without exceeding these plant factors.

Figure A.5 Total Electric Load as Modeled in BESOM and DESOM

Table A.1 Electric Energy Sources

<u>BASIC FUEL</u>	<u>TECHNOLOGY</u>
<u>CENTRAL GENERATION</u>	
Coal	Steam Electric Steam Electric, Combined Cycle
Oil	Steam Electric Steam Electric, Combined Cycle Gas Turbine
Gas	Steam Electric
Nuclear	Light Water Reactor Liquid Metal Fast Breeder Reactor High Temperature Gas-Cooled Reactor
Hydroelectric	
Geothermal	
Electricity	Pumped Hydro
<u>DECENTRALIZED GENERATION</u>	
Solar	Solar Cells
Fossil Fuels	Fuel Cells
Fossil Fuels	Total Energy Systems

Figure A.6 Available Off-Peak Electric Energy

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APPENDIX (B)

WISE, THE WISCONSIN REGIONAL ENERGY MODEL*

PURPOSE AND SCOPE

The Wisconsin regional energy model describes the regional energy system within the context of the region's characteristics. It considers energy demand, conversion, transport, and environmental impacts, while taking into account technological and economic factors. The model was developed for Wisconsin but has been modified to simulate other states and regions. The primary purpose of the model is to provide a means for studying energy systems and testing the impact of alternative energy policies. The model is under continuing development thus this description applies to the model as it was as of the date of the referenced reports.

GENERAL DESCRIPTION OF WISE

WISE is a simulation model consisting of an integrated group of sub-models. The model can be conveniently subdivided into five major groups: (1) socioeconomic activities, (2) external energy supplies and prices, (3) end-use energy demands, (4) energy conversion and supply, and (5) environmental impacts. Figure B-1 shows how these components are interrelated.

The socioeconomic activities sub-models combine with the end-use energy demand sub-models to form the demand side of the energy model. The external energy supply sub-model and the energy conversion and supply sub-models combine to form the supply side of the energy model.

Demand

The driving elements in the demand submodel are the socioeconomic activities. There are two primary driving elements: population and level of economic activity. The socioeconomic activity submodels provide estimates of population and economic activity over the subregions of the state (or region). Most of the inputs to these submodels are exogenous, although feedbacks from other submodels are under development.

Population is projected by an independent submodel. It is basically an extrapolation of current trends, taking into consideration fertility, mortality and migration by subregions.

*This description is based upon a series of reports published by the Energy Systems and Policy Research Group, Institute for Environmental Studies, University of Wisconsin, Madison. Specific references are not given in the text since their number would have been excessive. The list of references consulted is given at the end of this appendix.

The major categories of economic activity considered are manufacturing, wholesale and retail sales, public service, and government activities. The levels of these activities are predicted on a per capita basis to separate out the effect of population from other factors. Industrial activity is disaggregated into the 20 major two-digit Standard Industrial Classification (SIC) categories. Activities of particular importance in the region were further disaggregated. Sales, public service, and government activities are measured in expenditure per capita. All of these activities are modeled exponentially; that is, the models are of the form:

$$X(t+1) = (1+a) X(t)$$

where $X(\cdot)$ is the level of the activity and the parameter a expresses the growth (or declination) rate. The parameter a may be determined on the basis of historical data, or may be chosen by the user to describe particular scenarios. The level of the next year's industrial and commercial activities are apportioned by subregion in proportion to their levels in the present year.

End uses are classified into five major economic sectors: transportation, agriculture, industrial, commercial and government, and residential. Each sector has its own demand submodel which determines the demand for particular fuels (including electricity). Some of the models explicitly consider the physical demand - heating, cooling, lighting, or processing, thus allowing for the possibility of substitution.

Transportation Energy Demand

The transportation submodel determines the annual demand for specific fuels used in transportation. The model also calculates pollutant emissions associated with the transportation requirements. The model has three components: passenger-auto transport, inter-city mass transport, and freight transport. Each submodel calculates the demand for each of the available transportation modes, the energy intensiveness of each mode, and the emission factor per unit of energy consumed and the total pollutants emitted. Policy decisions affect such factors as the split between automobiles and urban mass transit and the energy intensiveness of the various transportation modes. Such factors, as number of automobiles per capita, trip length and type, and automobile population characteristics are considered. Figure B-2 shows a schematic representation of the automobile submodel.

Industrial Energy Demand

The industrial energy demand submodel assumes that energy requirements are a linear function of the industrial output. The industrial energy demands are disaggregated to the same SIC level utilized in the economic activity submodel. The demand for each fuel type by an industry is given by the value added for that

Figure B-1 The Relationships Between the Major Components of WISE

Figure B-2 The Passenger/Automobile Submodel

industry (as determined by the economic activity model) and the energy intensity, the amount of the fuel required per unit of value added in that industry. The energy intensiveness coefficients are based on historical relationships. Engineering design models are under development.

Residential Energy Demand

The residential energy demand submodel calculates the annual energy consumption by the residential consumers. The energy demand is calculated as the product of the number of households and the energy demand per household. The number of households is determined from the demographic data projected by the population submodel. The per household energy demand is estimated on the basis of type of home and ownership fractions of seventeen major household appliances. The ownership fractions of the various appliances for each type of home are based on exogenously-specified trends and saturation values.

Commercial Energy Demand

Two alternative commercial energy models have been developed. The first is based on historical trends relating energy consumption to commercial and government expenditures. In this model, the energy consumption is calculated with equations of the form:

$$EC_{j,t} = POP_t(CSPC_t \times EICS_{j,t} + GEPC_t \times EIGE_{j,t})$$

where:

POP = Population
CSPC = Per capita commercial sales
EICS = Energy intensity for commercial sales
GEPC = Per capita government expenditures
EIGE = Energy intensity for government expenditures
t = Time
j = Fuel j

Trends may be modified by the user to simulate different scenarios.

The second commercial energy model is based on physical end uses of energy such as lighting, space conditioning, and commercial processes. In this model, the key driving variable is the total floor area in use for commercial activities and by government. Energy consumption in each of the categories is related to floor area by engineering design requirements. Figure B-3 illustrates the structure of the commercial energy consumption submodel.

Agricultural Energy Demand

The final major energy demand category is agriculture. Agricultural energy demand is divided into the two major components: crops and livestock. For the crop model, the two

primary inputs are acreage of each crop and energy intensity per acre of each crop. These factors are calculated from historical or assumed trends. The livestock submodel calculates the livestock population for each simulation year subject to constraints on total digestible nutrients available, fuel availability, milk marketed, and livestock exported to other regions. The total energy consumed is calculated by multiplying the livestock population by fuel consumed per animal. Fuel consumed is converted to units of energy to give the total energy consumed by the livestock sector.

The agricultural energy model also calculates the indirect energy consumption associated with the region's agriculture. Indirect energy includes such components as the energy contained in and used in the manufacture of chemical fertilizer manufactured outside the region.

Supply

The supply side of the model consists of the two subgroups: external energy supplies and prices, and energy conversion and supply. Since Wisconsin imports all of its primary energy sources, the external energy supplies submodels are essentially a set of exogenous specifications in the form of fuel price, availability, source energy content, and so forth, as a function of time. The capacity of the fuel distribution system and the limitation that it may impose on fuel consumption is an integral part of the external energy supply submodel.

Energy Conversion Processes

Since most of the energy consumed in Wisconsin is imported, the only energy process modeled is the electricity supply industry. It is modeled in two separate components: the transmission and distribution submodel, and the generation capacity submodel. Demand for electric energy drives capacity expansion and other costs in both submodels. These costs are fed into a price determining model which compares the new price with the initial price and then adjusts demand accordingly. The cycle is repeated until the demand is consistent with the price. Figure B-4 illustrates these interfaces among the submodels.

A detailed description of the electricity supply submodels follows the description of the environmental impact submodels below which completes the general description of the WISE model.

Environmental Impact Submodels

The environmental impact submodels interact with the other component submodels to calculate the quantifiable environmental impacts resulting from energy use within the region. Environmental impacts considered include effects on land, air, water, structures, and living things. Environmental impacts are not only within the region being studied (e.g., Wisconsin), but also for the

Figure B-3 Commercial Energy Consumption Submodel

Figure B-4 Interfaces Among Electric Energy Submodel Components

entire energy flow system; fuel extraction through end-use. Environmental impacts associated with the generation and use of electricity are calculated separately from those associated through the use of other energy forms. The general form of the evaluation is given by:

$$QEI_{ijk} = (IF_{ijk}) \times (E_{kj})$$

where:

QEI = Quantified environmental impact
IF = Impact factor
E = Electric energy capacity

and the subscripts are defined by:

i = Type of impact
j = Year of impact
k = Electrical generation source

Figure B-5 illustrates the different types of environmental impacts associated with electric energy generation and use that are considered in WISE.

Environmental impacts associated with other forms of energy use are calculated by other submodels, but their form is very similar to the electric energy impact model. The program evaluates the impacts associated with the supply, conversion and use of the three primary fuels, coal, petroleum and natural gas. For example, it evaluates the environmental impact associated with vehicle emissions, as well as those resulting from extraction, transportation, refining and conversion of petroleum.

ELECTRIC ENERGY SUBMODEL

The electric energy supply industry is modeled by two separate submodels, the electrical generation capacity submodel, and the electricity transmission and distribution submodel.

The generation submodel performs three main functions:

1. Conversion of demand requirements to generating capacity requirements;
2. Simulates adding capacity to the system, considering prices and the availability of fuels and technologies;
3. Calculates production costs, including capital costs, fuel costs and operating costs.

A schematic diagram of the capacity requirements submodel is shown in Figure B-6. Capacity requirements are calculated using an exogenously specified load duration curve and capacity utilization data. A realistic capacity retirement scheme is used which first downgrades and then retires units as they age.

The capacity addition procedure is outlined schematically in Figure B-7. The user may specify either a capacity expansion strategy, a specific expansion plan, or a combination of the two procedures.

Cost calculations are estimated over the projected lifetime of the plants. Factors that are considered in the model are trends in capital costs and fuel costs, operations and maintenance costs, and adjustment costs which internalize environmental protection costs.

Transmission and Distribution Submodel

The transmission and distribution submodel estimates the costs associated with additions required to strengthen and extend the T&D system to meet projected demands. End-use demand is broken down into eight load density regions for which T&D costs associated with incremental power demand are calculated. Another component of T&D costs is based on the number of new customers in various groups as projected by the socioeconomic submodels for each subregion.

Electricity Revenue - Pricing Submodel

The costs calculated by the electrical generation capacity submodel and the transmission and distribution submodel are then fed into the electricity revenue - pricing submodel which determines the revenue requirement implied by the costs of electricity production. Prices are calculated on the basis of the specified demand and the revenue requirement. This price is then compared with the price that was assumed when the demand was determined. If the prices differ significantly, the demand is adjusted and the whole generation and T&D expansion analysis is iterated until the prices converge.

Figure B-5 Environmental Impact Associated with Electrical Generation

Figure B-6 Capacity Requirements Submodel

Figure B-7 Capacity Addition Procedure

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APPENDIX (C)
THE HUDSON-JORGENSON MODEL*

PURPOSE AND SCOPE

The Hudson-Jorgenson (H-J) model is an econometric submodel of domestic economic growth integrated with an input/output (I/O) framework of inter-industry transactions. The combination of these two submodels produces a model which can address issues on: (i) the interaction between economic activity and energy consumption, (ii) the allocation of resources (energy, materials, labor and capital) among competitive uses, and (iii) changes in the methods of production due to changes in the prices of factor inputs and final outputs. The motivation for the H-J model was development of a tool which could assess the impact of economic policy on aggregate demand and supply. Previous models by others had ignored the supply side. Hence, an I/O model of transactions between, say, output from industry A to the production process for other industries, B, C, and D, etc. was a reasonable addition to an econometric model of aggregate demand--especially since the techniques of I/O analysis had been fully developed and its properties were well known.

It is informative to point out the exogenous factors in the H-J model--those factors which must be assumed in order to drive the model, and the variables it is capable of explaining or predicting. In so doing, the reader might be more appreciative of the motivation for the many components and submodels in the H-J model. The following is a list of factors which must be assigned values in order to derive any model output:

- Population (age and structure);
- Household wealth;
- Time resources;
- Transfer benefit rates;
- Government demand for consumption, investment and labor services;
- Export demand for consumption, investment and labor services;
- Labor income tax rates;
- Capital efficiency rate;

*The description herein primarily is based on Hudson and Jorgenson [1] and several other articles which directly employ the model or comment on its structure. Specific references are not in the text of this appendix, however, a list of references is supplied at the end.

- Price* of capital services;
- Production efficiency;
- Price* of imports;
- Energy data (base year fuel prices).

Many of the exogenous variables are broken down for nine distinct industry sectors. The motivation of disaggregating by sector is that the H-J model then becomes flexible on the supply-side; i.e., producers are allowed to vary factor inputs and output according to price signals, domestic availability, and final demand. Further, the disaggregation allows the H-J model to examine energy and nonenergy industries as separate entities. The modelers felt that the following industries would be most directly affected by policy changes:

- A. Agriculture, nonfuel mining, and construction
- B. Manufacturing, excluding petroleum refining
- C. Transportation
- D. Communications, trade, and service
- E. Coal mining
- F. Crude petroleum and natural gas
- G. Petroleum refining
- H. Electric utilities
- I. Gas utilities

Note that Sectors A through D deal with non-energy production, and Sectors E through I produce energy-related products. Given the nine sectors by which the model is disaggregated and the input assumptions, values for the following variables are produced by the econometric growth submodel:

- A. A price possibility frontier for all output prices
- B. Real consumption demand
- C. Technical input/output coefficients
- D. Personal consumption expenditure on the goods produced by the nine industrial sectors
- E. Final demands for all inputs

*Price in this context and throughout this appendix will stand for aggregate price; an index or implicit price deflator.

The growth model results for A, C, and E are directly employed in the I/O model to derive values by sector for:

- A. Inter-industry transactions
- B. Final demand for all goods
- C. Value of primary inputs in current and real dollars
- D. Physical flows of energy for the five energy sectors, and price (both real and nominal) for each

The remainder of this appendix will explain in greater detail the mechanics of the H-J model and the two major components dealing with economic growth and inter-industry transactions. The next two sections describe the two major components. The remaining sections discuss the methods of driving inter-industry transactions, final demand and producer behavior, respectively.

GROWTH MODEL

The econometric growth model is required to provide totals for consumption, investment, government and export final demand in order to estimate inter-industry transactions. Also, the growth model estimates the relative prices of capital and labor services, which enter as primary inputs into the nine industrial sectors. A flow diagram of the economic growth model can be found in Figure C-1.

There are five behavioral equations for households and businesses which explain investment supply, labor demand, the production possibility frontier, consumption demand, and the demand for leisure. The mathematical forms of these equations can be found in Table B.1. The parameters for the equations in Table B.1 are estimated from historical data for the U.S., 1929-1971. All the behavioral equations are linear or log-linear. The demand for labor is determined by the total level of production, the amount of capital services available, and the relative price of capital and labor services. Output of investment goods (investment supply) is determined by the price of investment goods, the price of capital services and the available supply of capital services, and the amount of productive capacity being devoted to consumer goods and services. The total production of the economy (the production possibility frontier) is limited by total productive capacity which in turn depends on available supplies of capital and labor, and the level of technology.

The level of expenditure on consumer goods and services (consumption demand) is a function of the wealth of the household sector lagged one year, and resources of households, including government transfer payments and time. The desired amount of work for the household sector (leisure demand) is determined by the total

amount of time available, the wage rate, total wealth lagged one year and transfer payments.

In addition to the five behavioral equations, the model includes nine accounting identities which can also be found in Table C.1. Using the notation provided and explained in Table C.2, the interpretation of the identities should be obvious.

The model equates the demand and supply for consumption goods, investment goods, time and labor services. These equations can be found in Table C.3. Again, the balance equations are trivial in that the sum of each sectors demand equals the sum of goods and services supplied to that sector. Finally, there are two aggregation equations in Table C.3 that determine inventory accumulation of consumption goods. Although gross private domestic investment is determined in the model, the allocation of investment between fixed investment and inventory is not. Thus, the aggregation equations are necessary to balance demand and supply for investment and consumption.

THE INTER-INDUSTRY MODEL

The inter-industry model permits the analysis of the entire chain of production from the purchase of primary inputs through various stages of production to the emergence of products which are absorbed into consumption, investment, government or export final demand. Production is classified into nine sectors, each of which is a homogenous decision making unit for purchasing primary inputs, purchases from and sales to the other producing sectors, and selling finished products to final users. A flow diagram of inter-industry transactions can be found in Figure C-2.

The diagram on Figure C-2 might be thought of as a matrix of values whereby rows 10 through 13 represent levels of input and columns 10 through 14 represents levels of output. The inter-industry transaction matrix represents the technological coefficients which transfer levels of input into a given quantity of output. The derivation of the technological coefficients is discussed in greater detail in the following section.

In order to project energy demand and supply, one must take the levels of final demand (columns 10 through 13 in Figure C-3) from the econometric growth model. Then, assume that for the five energy sectors, the price and quantity of imports are exogenous, but one can determine through the econometric growth model the import quantities along with the quantities of capital and labor services in each industry. The equilibrium price of capital and labor are determined within the econometric growth model. The quantities of exports and government purchases of the output from each industry are treated exogenously.

Figure C-1 Flow Chart of the Econometric Model

Table C.2 Behavioral Equations and Accounting Identities
for H-J Econometric Growth Model

1. BEHAVIORAL EQUATIONS
<p>INVESTMENT SUPPLY: $\frac{PIS \cdot IS}{PKD \cdot KD} = 1.1717 - 0.5006 \cdot (\log CS - \log IS).$</p> <p>LABOR DEMAND: $\frac{PLD \cdot LD}{PKD \cdot KD} = 1.5655.$</p> <p>PRODUCTION POSSIBILITY FRONTIER: $0 = -\log KD - 1.5655 \cdot \log LD + 1.3938 \cdot \log CS - 2.5655 \cdot \log A + 1.1717 \cdot \log IS + 0.2503 \cdot (\log CS - \log IS)^2.$</p> <p>CONSUMPTION DEMAND: $PC \cdot C = 0.0034 \cdot W(-1) + 0.1469 \cdot (PL \cdot LH + EL).$</p> <p>LEISURE DEMAND: $PL \cdot LJ = 0.0196 \cdot W(-1) + 0.8403 \cdot (PL \cdot LH + EL).$</p>
2. ACCOUNTING IDENTITIES
<p>CAPITAL STOCK AND INVESTMENT: $K = AI \cdot I + (1-M) \cdot K(-1).$</p> <p>CAPITAL SERVICE AND CAPITAL STOCK: $KD = AK \cdot K(-1).$</p> <p>VALUE OF OUTPUT AND INPUT: $PIS \cdot IS + PCS \cdot CS = PKD \cdot KD + PLD \cdot LD.$</p> <p>VALUE OF CONSUMPTION GOODS: $(1 + TC) \cdot PCS \cdot CS + PCE \cdot CE = PC \cdot C + PCG \cdot CG + PCI \cdot CI + PCR \cdot CR.$</p> <p>VALUE OF INVESTMENT GOODS: $(1 + TI) \cdot PIS \cdot IS + PCI \cdot CI = PI \cdot I + PIG \cdot IG + PIR \cdot IR.$</p> <p>VALUE OF CAPITAL SERVICES: $(1 - TK) \cdot (PKD \cdot KD - TP \cdot PI(-1) \cdot AW(-1) \cdot K(-1)) = N \cdot PI(-1) \cdot AW(-1) \cdot K(-1) + D \cdot PI \cdot AL \cdot K(-1) + PI(-1) \cdot AW(-1) \cdot K(-1) - PI \cdot AL \cdot K(-1).$</p> <p>VALUE OF LABOR SERVICES: $(1 - TL) \cdot (PLD \cdot LD + PLGE \cdot LGE + PLGG \cdot LGG + PLR \cdot LR) = PL \cdot L.$</p> <p>SAVING: $S = PI \cdot I + PG \cdot (G - G(-1)) + PR \cdot (R - R(-1)).$</p> <p>WEALTH: $W = PI \cdot AW \cdot K + PG \cdot G + PR \cdot R.$</p>

NOTE: Parameters for behavioral equations based on U.S. economy, 1929-1971 (see Hudson and Jorgenson [1974].)

Notation definitions can be found on Table C.2.

Table C.2 H-J Econometric Growth Model Variable Notation

1. AGGREGATION VARIABLES	
A TOTAL FACTOR PRODUCTIVITY (INPUT TO OUTPUT).	AK CAPITAL STOCK, LAGGED TO CAPITAL SERVICE.
ACI INVESTMENT TO CHANGE IN BUSINESS INVENTORIES, CONSUMPTION GOODS.	APC IMPLICIT DEFLATOR OF CONSUMPTION GOODS TO IMPLICIT DEFLATOR OF CHANGE IN BUSINESS INVENTORIES, CONSUMPTION GOODS.
AI INVESTMENT TO CAPITAL STOCK.	AW INVESTMENT TO WEALTH.
AL INVESTMENT TO CAPITAL STOCK, LAGGED.	
2. QUANTITIES	
C PERSONAL CONSUMPTION EXPENDITURES, INCLUDING SERVICES OF CONSUMERS' DURABLES.	IG GOVERNMENT PURCHASES OF INVESTMENT GOODS.
CE SUPPLY OF CONSUMPTION GOODS BY GOVERNMENT ENTERPRISES.	IR NET EXPORTS OF INVESTMENT GOODS.
CG GOVERNMENT PURCHASES OF CONSUMPTION GOODS.	IS SUPPLY OF INVESTMENT GOODS BY PRIVATE ENTERPRISES.
CI CHANGE IN BUSINESS INVENTORIES OF CONSUMPTION GOODS.	L SUPPLY OF LABOR SERVICES.
CR NET EXPORTS OF CONSUMPTION GOODS, LESS INCOME ORIGINATING, REST OF THE WORLD.	LD PRIVATE PURCHASES OF LABOR SERVICES.
CS SUPPLY OF CONSUMPTION GOODS BY PRIVATE ENTERPRISES.	LGE GOVERNMENT ENTERPRISES PURCHASES OF LABOR SERVICES.
G NET CLAIMS ON GOVERNMENT.	LGG GENERAL GOVERNMENT PURCHASES OF LABOR SERVICES.
R NET CLAIMS ON REST OF THE WORLD.	LH TIME AVAILABLE.
I GROSS PRIVATE DOMESTIC INVESTMENT, INCLUDING PURCHASES OF CONSUMERS' DURABLES.	LJ LEISURE TIME.
	LR NET EXPORTS OF LABOR SERVICES.
	LU UNEMPLOYMENT
	K CAPITAL STOCK.
	KD CAPITAL SERVICES.
3. PRICES	
PC IMPLICIT DEFLATOR, PERSONAL CONSUMPTION EXPENDITURES, INCLUDING SERVICES OF CONSUMERS' DURABLES.	PIG IMPLICIT DEFLATOR, GOVERNMENT PURCHASES OF INVESTMENT GOODS.
PCE IMPLICIT DEFLATOR, SUPPLY OF CONSUMPTION GOODS BY GOVERNMENT ENTERPRISES.	PIR IMPLICIT DEFLATOR, NET EXPORTS OF INVESTMENT GOODS.
PCG IMPLICIT DEFLATOR, GOVERNMENT PURCHASES OF CONSUMPTION GOODS.	PIS IMPLICIT DEFLATOR, SUPPLY OF INVESTMENT GOODS BY PRIVATE ENTERPRISES.
PCI IMPLICIT DEFLATOR, CHANGE IN BUSINESS INVENTORIES OF CONSUMPTION GOODS.	PL IMPLICIT DEFLATOR, SUPPLY OF LABOR SERVICES.
PCR IMPLICIT DEFLATOR, NET EXPORTS OF CONSUMPTION GOODS, LESS INCOME ORIGINATING, REST OF THE WORLD.	PLD IMPLICIT DEFLATOR, PRIVATE PURCHASES OF LABOR SERVICES.
PCS IMPLICIT DEFLATOR, SUPPLY OF CONSUMPTION GOODS BY PRIVATE ENTERPRISES.	PLGE IMPLICIT DEFLATOR, GOVERNMENT ENTERPRISES PURCHASES OF LABOR SERVICES.
PG IMPLICIT DEFLATOR, NET CLAIMS ON GOVERNMENT.	PLGG IMPLICIT DEFLATOR, GENERAL GOVERNMENT PURCHASES OF LABOR SERVICES.
PR IMPLICIT DEFLATOR, NET CLAIMS ON REST OF THE WORLD.	PLR IMPLICIT DEFLATOR, NET EXPORTS OF LABOR SERVICES.
PI IMPLICIT DEFLATOR, GROSS PRIVATE DOMESTIC INVESTMENT, INCLUDING PURCHASES OF CONSUMERS' DURABLES.	PKD IMPLICIT DEFLATOR, CAPITAL SERVICES.
4. FINANCIAL VARIABLES	
D RATE OF DEPRECIATION, PRIVATE DOMESTIC TANGIBLE ASSETS.	N NOMINAL RATE OF RETURN, PRIVATE DOMESTIC TANGIBLE ASSETS.
M RATE OF REPLACEMENT, PRIVATE DOMESTIC TANGIBLE ASSETS.	S GROSS PRIVATE NATIONAL SAVING.
	W PRIVATE NATIONAL WEALTH.
5. TAX AND TRANSFER VARIABLES	
EL GOVERNMENT TRANSFER PAYMENTS TO PERSONS, OTHER THAN FROM SOCIAL INSURANCE FUNDS.	TK EFFECTIVE TAX RATE, CAPITAL SERVICES.
TC EFFECTIVE TAX RATE, CONSUMPTION GOODS.	TL EFFECTIVE TAX RATE, LABOR SERVICES.
TI EFFECTIVE TAX RATE, INVESTMENT GOODS.	TP EFFECTIVE TAX RATE, CAPITAL STOCK.

INTERMEDIATE SECTORS:

1. AGRICULTURE, NONFUEL MINING AND CONSTRUCTION.
2. MANUFACTURING, EXCLUDING PETROLEUM REFINING.
3. TRANSPORT.
4. COMMUNICATIONS, TRADE, SERVICES.
5. COAL MINING.
6. CRUDE PETROLEUM AND NATURAL GAS.
7. PETROLEUM REFINING.
8. ELECTRIC UTILITIES.
9. GAS UTILITIES.

PRIMARY INPUTS, ROWS:

10. IMPORTS.
11. CAPITAL SERVICES.
12. LABOR SERVICES.

FINAL DEMAND, COLUMNS:

10. PERSONAL CONSUMPTION EXPENDITURES.
11. GROSS DOMESTIC PRIVATE INVESTMENT.
12. GOVERNMENT PURCHASES OF GOODS AND SERVICES.
13. EXPORTS.

Figure C-2 H-J Inter-Industry Transaction Model

**Table C.3 Balance Equations and Aggregation Equations
for H-J Econometric Growth Model**

BALANCE EQUATIONS	
CONSUMPTION:	
	$CS + CE = C + CG + CI + CR.$
INVESTMENT:	
	$IS + CI = I + IG + IR.$
TIME:	
	$LH = L + LJ.$
LABOR:	
	$L = LD + LGE + LGG + LR + LU.$
AGGREGATION EQUATIONS	
IMPLICIT DEFLATOR, CHANGE IN BUSINESS INVENTORIES, CONSUMPTION GOODS:	
	$PCI = PC \cdot APC.$
CHANGE IN BUSINESS INVENTORIES, CONSUMPTION GOODS:	
	$PCI \cdot CI = PI \cdot I \cdot ACI.$

Prices of domestically available output are determined using the I/O inter-industry transaction model. Then, using the model of consumer behavior, it is possible to estimate consumer demand among the commodity groups. Personal consumption expenditures also include non-competitive imports, the services of dwellings and the services of consumer durables. The price of noncompetitive imports is exogenous. The capital service prices for consumer durables and housing services are a function of the price of capital services determined from the macroeconomic model.

INTER-INDUSTRY TRANSACTIONS

The following section briefly describes the mechanics of determining the transactions between the industries. We adopt the following notation from Hudson and Jorgenson (1);

XI_{IJ} = Intermediate demand for the output of industry I by industry J
 YI = Final demand for output of industry I
 XI = Domestic availability of the output of industry I
 PI = Price of output of industry I

There are nine balance equations which equate demand with supply:

$$XI = \sum_{J=1}^9 XI_{IJ} + YI \quad I=1,2,\dots,9 \quad (C.1)$$

There exists an accounting identity for each output whereby the value of output equals the sum of the values for intermediate inputs, capital services, labor services, and, for the four nonenergy sectors, the value of imports of competing products:

$$PI * XI = \sum_{J=1}^9 PJ * XJI + PK * KI + PL * LI + PRI * RI \quad I=1,2,\dots,9 \quad (C.2)$$

where:

KI = Quantity of capital services in industry I
 LI = Quantity of labor services in industry I
 RI = Competitive imports of the output of industry I
 PK = Price of capital services
 PL = Price of labor services
 PRI = Price of competitive imports of industry I

In projecting energy demand and supply, the H-J model takes the ratio of service prices for each industry to the corresponding prices from the econometric growth model to be exogenous. Further, the prices for capital and labor services are assumed to be the same across industries.

The inter-industry model includes models of producer behavior (discussed in detail below), for each of the nine industrial sectors. These models of producer behavior can be derived from the nine price possibility frontiers:

$$AI * PI = GI(P_1, P_2, \dots, P_9; PK, PU, PRI) \quad I=1,2,\dots,9 \quad (C.3)$$

where AI(I=1,2,...,9) is an index of the level of Hicks-neutral technology in industry I.

The price possibility frontier can be derived from three submodels which estimate:

- Price of output for nine industrial sectors
- Price of aggregate energy input
- Price of aggregate nonenergy input

Therefore, given the prices of capital services, labor services, aggregate energy input and aggregate nonenergy input, one can determine the price of output for each of the nine industrial sectors. This implies that to determine the price possibility frontier, it is necessary to simultaneously solve a twenty-seven equation system (three equations for each sector).

The next step is to derive the input/output (I/O) coefficients which are expressed as a function of prices. For each industry, the I/O coefficients are determined for the aggregate inputs of capital (K), labor (L), energy (E), and materials (M). Next, energy and nonenergy inputs are disaggregated into five energy types and five nonenergy types (imports are considered nonenergy inputs), thus yielding the nine industrial sectors and imports.

The I/O coefficients are computed for the ratios of each type of energy (nonenergy) input per unit of total energy (nonenergy) input. Multiplying the aggregate I/O coefficients by the disaggregated I/O coefficients for the ratios, yields the I/O coefficients for the inter-industry model.

FINAL DEMAND FOR DOMESTIC AVAILABILITY OF OUTPUT

Output is demanded from each of the nine industrial sectors for consumption investment, government services, and exports. Hence,

$$YI = CI + II + GI + ZI \quad I=1,2,\dots,9 \quad (C.4)$$

where:

YI = Final demand for output from industry I
 CI = Personal consumption expenditure on the output of industry I
 II = Gross private domestic investment using the output from industry I (gross private fixed investment plus inventory change)

ZI = Exports from the output of industry I

Levels of final demand (i.e., Y1, Y2, ...Y9) and supply are taken from the econometric growth model. The link between the two models is accomplished through the following four identities:

$$PC^*C = \sum PI^*CI \quad I=1,2,\dots,9 \quad (C.5)$$

$$PI^*I = \sum PI^*II \quad I=1,2,\dots,9 \quad (C.6)$$

$$PG^*G = \sum PI^*GI \quad I=1,2,\dots,9 \quad (C.7)$$

$$PZ^*Z = \sum PI^*ZI \quad I=1,2,\dots,9 \quad (C.8)$$

where the left hand expression for Equations C.5 through C.8 is set equal to the sum of expenditures of each of these categories over all nine industries from the econometric growth model. Exports, both in value terms and real dollars, are projected exogenously. Total government expenditures on goods and services are also exogenous. The remaining two categories of total expenditure are estimated by the econometric growth model. However, the allocation of investment among industries is exogenous.

The final step in determining final demand is the allocation of personal consumption expenditures among the nine industrial products (excluding crude petroleum and natural gas (prior to distribution) in effect making eight industrial products) and two categories not formally considered in the models, non-competitive imports and services of consumer durables. For this purpose, the H-J model employs an econometric model of consumer behavior of the following form:

$$\ln V = \ln V \frac{P1}{PC^*C} + \frac{P2}{PC^*C} \dots \frac{P11}{PC^*C} \quad (C.9)$$

where V is the level of utility, PI(I=1,2,...11) is the price of the Ith commodity and PC^*C is total personal consumption expenditure. The model expressed in Equation C.9 is commonly referred to in the literature as a Translog Indirect Utility Function. For more detail, see Christensen, Jorgenson and Lau [5], and Brock and Nesbitt [6]. Given this form of the utility function, it is implicitly assumed that the budget share on each commodity is fixed.

At this point in the discussion, the reader should have a fairly good understanding of the two major components of the H-J model, some of the mechanics in each submodel, and how they link together. It might be helpful to review Figure C-3 in order to better understand the interaction of the various components.

PRODUCER BEHAVIOR

Producers are assumed to be profit maximizing agents. They take input and output prices as given and therefore, must minimize the expense of production given their production possibili-

ties; (i.e., given the level of technology and the ease of substitution between inputs). Factor inputs are aggregated to four categories:

- Capital (K)
- Labor (L)
- Energy (E)
- Materials (M)

The H-J model constructs a price possibility frontier based on the aggregate input prices such that the function is separable and homogenous in the inputs within each aggregate. The energy aggregate is a function of inputs from coal, crude petroleum and natural gas, refined petroleum products, electricity, and gas utilities. The materials group is disaggregated by inputs from agriculture, manufacturing, transportation, communications, trade services, and competitive imports for the nonenergy sectors. The framework used to derive the frontier is referred to as the translog price possibility frontier. For each aggregate input, there is a translog function which expresses the value share of input relative to total value of output as a function of the price of aggregate factor inputs. To derive the input-output (I/O) coefficient for each aggregate, the value of share (e.g., the ratio $\frac{PK^*KI}{PI^*XI}$

for the value share of capital in the output of industry I) is divided by the ratio of factor input price to output price (e.g., PK/PI in the case of capital for industry I, thus, the inverse when multiplied by $\frac{PK^*KI}{PI^*XI}$,

yields KI/XI, or the I/O coefficient).

For a discussion of how the H-J model disaggregates the energy and materials price possibility frontiers, the reader should refer to Hudson and Jorgenson [1] pages 477-478.

Figure C-3 Flow Diagram of H-J Model

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APPENDIX (D)
THE SRI-GULF ENERGY MODEL

PURPOSE AND SCOPE

The SRI-Gulf Energy Model was first developed in 1973 for the Gulf Oil Corporation to analyze decisions on alternative synthetic fuels strategies. Since then various studies were performed for government agencies to investigate synthetic fuel commercialization programs, western regional energy development, fuel and energy price forecasts, energy RD&D programs and effects of a nuclear moratorium. As the original version of the model was developed for synthetic fuels decisions, the model and its subsequent versions contain a very detailed breakdown of the fossil-fuel supply, processing and use patterns.

The model treats the entire energy process, from production, processing, transportation and to end-use consumption. The processes are grouped into eight basic types:

1. Simple Conversion Processes describe the technology and economics of converting one energy material to another (i.e., synthetic gas from coal and residential space heat from gas).
2. Allocation Processes describe the allocation of demand among competing sources of supply (i.e., allocation of gas demand among alternative sources and space heat demand among alternative furnaces and fuels).
3. Primary Resource Processes describe the depletion and pricing of energy resources (i.e., natural gas and coal).
4. End-Use Demand Processes describe the growth in demand for usable energy over time and the effect on demand of changes in prices (i.e., space heat and industrial steam).
5. Transportation Processes describe technology and economics of moving an energy material from one location to another (i.e., natural gas pipelines and coal unit trains).
6. Complex Conversion Processes (i.e., refineries and electric power generation).
7. Secondary Industry Processes describe the impact on secondary material prices of changes in demand for secondary materials used in construction of new energy facilities (i.e., pressure vessels and surface mining equipment).

8. Price and Quantity Regulation Processes describe government controls on energy prices and quantities.

The processes are characterized by a set of physical and behavioral relations, describing the physical flows and human choices over time respectively.

The interactions between the processes are described by a network defining the links among them. Figure D.1 is a simplified schematic diagram that illustrates the network structure for the SRI-Gulf model. The network also provides the links between processes in different regions (see Figure D.2). Regions are distinguished between demand, and refinery supply regions. In total there are 9 demand regions, 15 supply regions and 6 refinery regions. The supply regions cover such primary resources as coal, nuclear fuels, shale, geothermal steam, crude oil, and natural gas.

The model is dynamic, spanning the next 50-years. Within each of the process models, installation and retirement of facilities over time is modeled, and in primary resources, depletion over time is included. End-use demands over time are derived by a simplified model of the economy and population growth.

General Equilibrium

The model seeks a general equilibrium defined by a set of prices and quantity of all processes over time that satisfy all physical and behavioral relations governing the processes and the linkages among the variables in the network. This methodology resembles many aspects of general economic equilibrium theory, whereby a set of equilibrium prices and quantities are determined until all markets are clear. However, the equilibrium solution of the SRI-Gulf model, reflects market imperfections and human behavior, including shortages introduced by price controls and other restrictions; idealized, perfect market behavior need not be assumed in the generalized equilibrium model. In addition, the equilibrium solution for a given time period depends on solutions in past and future time periods.

Network Solution Algorithm

The solution algorithm in the SRI-Gulf model is very much related to the network structure, by iterating prices and quantities "up" and "down" the network. The "up" and "down" is related to Figure D.1, where the demand is said to be at the top of the network and supply is at the bottom. The algorithm begins with an "upward pass", where the primary resource prices are first estimated (see Figure D.3) then product prices are computed along the network going up until the end-use energy prices are determined. The behavioral relations governing prices are used in the upward pass. Then the "downward pass" follows, computing quantities in each

Figure D.1 Elements of the SRI-Gulf Network

Figure D.2 Regional and Transportation Network Structure of the SRI-Gulf Model

Figure D.3 Overview of the Algorithm

process using all of the physical relations and the rest of the behavioral relations.

In iterating up and down the network, the prices or quantities of each process input or output are computed for all time periods before moving to the next process.

Features of Physical Relations

Each process has an assumed thermal conversion efficiency relating the inputs and outputs. The efficiency changes over time exogenously to represent technological changes. The capacity of all processes are modeled except for the allocation, and end-use demand, price and quantity regulation, secondary materials processes. The capacity of a process at any period is sized equal to the maximum of the output quantity and the capacity of the previous period (minus the capacity replacements). The capacity replacements are assumed to be the entire capacity of L -years ago, where L is the plant life of the process. The initial capacities of the processes are exogenously set to be the physical flow quantities in the initial year. The replacement capacities for the beginning years are exogenously set to be $\frac{1}{2L}$ of the initial year flow.

Secondary industrial material is included in simple and complex conversion processes and transportation processes. They are included simply as an assumed fraction of the capacity addition in the same period.

In the primary resource process, the cumulative committed production is modeled. The cumulative, committed production is related to the marginal cost by a long-term resource supply curve. The physical relations of the primary resource process simply determine $Q(t)$, the cumulative committed production from:

$$Q(t) = Q(t-1) + C_a(t) \cdot L \quad (D.1)$$

where $C_a(t)$ is the capacity addition in period t .

One special feature of the modeling of the demand process is the inclusion of end-use demand rather than fuel demands. For example, space heat is an end-use demand rather than the fuel inputs to the furnace to generate heat. The end-use demands are treated as non-substitutable as contrast to the fuel or technology competitions. The modeling of the end-use demand is very simplistic, as a function of regional population and price (marginal cost) of energy. The quantity of demand is first projected at given reference prices using projections, and then the actual price is calculated based on assumed constant price elasticity and a simple adjustment.

Complex conversion processes include electric power generation, refining, auxiliary input/output processes and joint natural gas and LPG production processes. These share the common characteristics of having either multiple inputs or multiple outputs conversion process. The treatment of the complex processes are different from one another. The electric power generation process will be discussed separately later.

Physical relations in price and quantity regulation processes describe government controls in the energy market. These take the form of exogenously setting or constraining process input or output and prices. The constraint relations are implemented by means of shadow prices (positive or negative, dependent on the constraint). Shadow prices are set by the network iteration algorithm until the constraint is satisfied.

Behavioral Relations on Quantities

There are special features in the behavioral relations in the allocation process. In modeling an allocation process, imperfect market behavior of lag in responses to price signals is considered. The behavioral relations of the market-share model combine a static and dynamic component. Suppose the demand for a given process can be satisfied by various supplies. The static quantity of supply q_j is assumed to be inversely related to the price p_j of the j th source. For example, for the case of two competing suppliers.

$$\hat{q}_j(t) = q_j(t) \frac{p_j(t)^{-\gamma}}{\sum_{\text{all } j} [p_j(t)]^{-\gamma}} \quad (D.2)$$

where γ is the market-share coefficient. Figure D.4 illustrates the effect of γ on the market share. The determination of γ is set exogenously.

The static market share is further adjusted to make provisions for "price premiums" to be added to the above market prices $p_j(t)$ to reflect inconvenience, aesthetic differences or other differences not reflected in the price. Again, the price premiums are set exogenously.

The lagging effect of slow responses to prices and that of uncertainty about future prices are modeled. This is done with simple adjustments to the static allocation, by separating the sensitivity of existing demand and new demand to prices. Existing demand, q_j^l , and new demand $q_j^n(t)$ are defined by:

$$q_j^l(t) = \min [q_j(t), q(t-1)] \quad (D.3)$$

$$q_j^n(t) = q_j(t) - q_j^l(t) \quad (D.4)$$

The new demand is allocated as follows:

$$q_j^n(t) = q^n(t) \left[\beta_n \frac{\hat{q}_j(t)}{q(t)} + (1-\beta_n) \frac{q_j(t-1)}{q(t)} \right] \quad (D.5)$$

where β_n is the behavioral lag parameter, representing the response in one year to the change in static market share from the previous year's actual market share. The value of β_n is set exogenously. Similarly, the existing demand is allocated similarly, with a different lag parameter. The total demand is defined as the sum of existing and new demand.

The market-share relations are slightly different for price and quantity regulation processes, where $p_j(t)$ in Equation D.2 is replaced by the sum of the shadow prices and price premium.

There is behavioral relation governing secondary industry capacity, $\tilde{w}(t)$ by:

$$\tilde{w}(t) = \alpha w(t) + (1-\alpha) \tilde{w}(t-1)$$

where $w(t)$ is the quantity of secondary material flow and α is the response of the system capacity to demand, reflecting a time lag to allow for planning and decision-making and actual construction.

Figure D.4 Market Share Curve

Figure D.5 Discrete Approximation of Generation Needed to Satisfy the Load Duration Curve

Figure D.6 Electric Power Subnetwork

Figure D.7 Demand Region Conversion Sector Detail

Behavioral Relations on Prices

Product prices are related over time. For a slowly growing market, prices of each period, $p(t)$, are assumed to be set so that the net present value of a marginal unit of capacity would be zero at the industry rate of return, r , used as a discount rate. That is:

$$p(t) = \phi(t) + \left[\frac{k_d}{1-f_{\text{tax}}} - \sum_{\tau=t+1}^{t+L} \frac{p(\tau) - \phi(\tau)}{(1+r)^{\tau-t}} \right] \quad (D.6)$$

where $\phi(t)$, k_d are the operating and the tax adjusted discounted capital cost presented below; and f_{tax} is the tax rate. The term in the brackets reflects the difference between the tax adjusted discounted capital cost of the facility and the value of the facility in future years. In the above expression, $p(t)$ is solved recursively backward in time, starting from a set of assumed terminal values of $p(\tau) - \phi(\tau)$ being constant.

The products price for industries under rapid growth and with excess capacity are respectively modeled with different growth multipliers adjusting the term in brackets of (D.6).

The operating cost includes fuel-related and non-fuel related components:

$$\phi(t) = v(t) + p_f \cdot \frac{1}{e}$$

where $v(t)$ is the non-fuel operating cost per unit output, p_f is the price of input quantity and e is the thermal efficiency.

Initial capacity cost specified in the first period is adjusted to account for (1) technological change, (2) inflation, (3) secondary materials cost, and, (4) present value discount including investment tax credit, depreciation, and interest during construction. In all these adjustments, exogenous parameters reflecting various assumptions are used.

The pricing scheme for primary resource process is different from that of the simple conversion process. First, marginal cost as a function of time, $m(t)$, is determined from the long-run supply curve $m(Q)$ as follows:

$$m(t) = m(Q(t)) \cdot f_i(t) \cdot f_e(t) \quad (D.7)$$

where $f_i(t)$ is the inflation adjustment factor and $f_e(t)$ is the technological change factor which is represented as a function of time.

Then the long-run price, $\hat{p}(t)$, of the primary source is determined by adding to $m(t)$ a term called economic rent, as follows:

$$\hat{p}(t) = m(t) + \max_{\tau > t} \frac{p(\tau) - m(\tau) \cdot f(t, \tau)}{(1+r)^{\tau-t}}$$

where $f(t, \tau)$ is the adjustment factor for technological change and inflation. This is supposed to capture the decision-making of a resource owner that has the alternative of postponing investment and production anticipating higher future prices. In the above formulation, future prices and costs affect current prices. The terminal value for $p(t)$ must be assumed.

Pricing in the secondary materials is determined by price function dependent on the ratio of secondary materials demand to nominal capacity.

ELECTRIC POWER GENERATION

Electric power generation is one of the complex conversion processes that have multiple input or multiple outputs. The SRI-Gulf model represents electric power demand with a discrete number of electric demands at various usage levels. Each demand category is distinguished by its load factor LF_i , which should correctly be interpreted as capacity factors. The electric demands are represented in the energy model network as distinct materials. In all its applications, three materials categories, representing base, cycling, and peaking power load demands, are as shown in Figure D.5.

Electric power generation processes in each demand region are represented by a subnetwork, as illustrated in Figure D.6. This subnetwork includes a load disaggregation process of total power demand, an allocation process for each demand category, and several electric power conversion processes representing different generation technologies. A detailed illustration of the power generation subnetwork for one of the demand regions with 27 power generation technologies is illustrated in Figure D.7. Storage technologies are included as either "peak load storage" that converts base load electricity to peak load electricity or as "intermediate load storage" which converts base load electricity to cycling load.

The load disaggregation process exogenously separates the total demand into base, cycling, and peaking generation. The fraction $a_j(t)$ of the total electric energy in demand category j , is assumed to be five percent for peak, twenty-five percent for cycling, and seven percent for base load for all regions and all periods. These energy fractions are not load factors. There is no explicit relation between the fraction $a_j(t)$ and the end-use demand of industrial electro-mechanical use; industrial heat, air conditioning, space heating and water heating.

The method of allocation for base, cycling and peaking demands among different power conversion technologies uses exactly the same physical and behavioral relations as those of the allocation process described earlier. The generation technologies shown in Figure D.6 are similar to the simple conversion process except for the multiple outputs. Suppose q_j are the outputs from a power conversion process to demand category j , the capacity of the process c_j is given by:

$$c = \sum_i \frac{q_i}{LF_i}$$

The behavioral relations for the power conversion processes are the same as those of simple conversion process except the following:

$$p_i(t) = \phi(t) + \left[\frac{k_d}{1-f_{\text{tax}}} - \sum_{\tau=t+1}^{t+L} \frac{p(\tau) - \phi(\tau)}{(1+r)^{\tau-t}} \right] I(t) \frac{1}{LF_i(t)}$$

The reliability of reserve requirement of generation are not explicitly included, except that their costs, LF_i , are possibly included by adjustments in the capital costs, $k_d(t)$ and the load factors, LF_i .

The secondary materials included in the power conversion (generation) processes are of three types: electric power process construction, pressure vessel manufacture, and gas turbine manufacture.

On the whole, the modeling of electric power generation behavior is, except for the minor adjustments above, exactly the same as any other process or industry. There is no characterization of the fact that the electric utility industry is regulated.

The treatment of transmission and distribution (T&D) equipment is peculiar. T&D facilities are categorized into either industrial electricity distribution, residential/commercial electricity distribution (except space heat), and residential/commercial electricity distribution (for space heat). In addition, the T&D costs are not related to the capacity of power conversion process.

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APPENDIX (E)

REGIONALIZED ELECTRICITY MODEL (REM)*

PURPOSE AND SCOPE

The primary purpose of the model is to provide an integrated and consistent tool for analyzing technical and policy alternatives facing the U.S. electric utility industry and concerned policy-makers. The model is a regionalized dynamic simulation of the U.S. electric utility industry. It estimates the demand for electric energy and operations necessary to supply the demand energy. These are subject to a number of assumptions about future fuel prices, regulatory policy for utilities, load management, and so forth. By varying these assumptions, their effect on the electric utility industry can be studied.

GENERAL DESCRIPTION OF REM

REM combines an econometric demand submodel with an engineering supply submodel by means of a utility industry finance/price submodel to form a simulation model of the U.S. electric energy system. The model simulates a 50-year time period in half-year steps. Spatially, the model has nine homogenous subregions, corresponding to the nine U.S. census regions.

The model consists of three basic parts, each of which addresses itself to a certain aspect of the electricity market. The first of these is a regional supply model which simulates the decision-making processes involved in operating and expanding an electricity supply system. Cost-minimizing criteria are used to simulate electricity generation and expansion planning. However, these criteria are essentially behavioral in nature and correspond to the "rule-of-thumb" approach to cost minimization that is used by electric utility companies.

The second component models the demand side of the market. A system of demand equations simultaneously estimate the demands for electricity, natural gas, coal, and oil consumed in the residential-commercial and industrial sectors. The demand system is dynamic and nonlinear, the relevant elasticities having been estimated econometrically using a time series of cross sections for 49 states.

The final component of the model is a regulatory/financial submodel which links the demand and supply sides by setting prices for electric services. It consists of a set of behavioral equations and accounting identities which represents the regulatory rules used by state regulatory commissions to establish electricity prices. It also simulates the financing decision-making processes in the electric utility industry. The regulatory/financial model can be used by itself or along with the supply/demand system to analyze the effects that changes in regulatory procedures, tax and depreciation rules, and industry policies have on utility behavior. A schematic diagram of the overall model is shown in Figure E.1. The primary building blocks are the calculation of (1) firm expectations of the major decision variables, nationally and regionally, (2) the system expansion plans and new plant construction to meet expected load, (3) the generation of electricity via usage of existing plant to meet actual load, (4) transmission and distribution requirements and costs, (5) the "cost of service" and utility cash flows, and, (6) actual electricity demands for the alternative customer classes consistent with the endogenous set of electricity prices.

Supply Submodel

Steps (1) through (4) listed above correspond to the supply component of the model. The current and projected values of fuel costs, plant construction costs, and plant operating characteristics are exogenous inputs into the model. The forecasted value of demand, which drives expansion planning, is based on a simple model which uses exponentially weighted moving average with trend adjustment. The simulated actual demand is calculated by means of a set of econometric demand equations (described below). Thus, there will generally be a difference between forecasted demand and "actual" demand. This difference, which reflects the actual experience of electric utilities, causes the generation mix to be different from the optimal mix that would have been built had the future been predicted exactly. Utilities can adjust their plans as the time of the actual demand approaches, but lead time constraints prevent ideal readjustments.

* This description is based upon [1] and [2].

Figure E.1 Schematic of Model Linkages, Exogenous Data Needs, and Central Computational Components

The electric utility expansion plans are based on the projected load duration curve and the production costs of the eight different plant types considered. Load duration curves specify the duration per period that load equals or exceeds each of the values that it takes on during the period. The plant types are (1) gas turbines, (2) coal-fired thermal, (3) natural gas-fired thermal, (4) oil-fired thermal, (5) light water uranium reactors, (6) high temperature gas reactors, (7) plutonium recycle reactors, and (8) liquid metal fast breeder reactors. Hydroelectric plants are also considered, but their schedule is specified exogenously. The average production costs for each of the plant types is expressed in the form:

$$AC = 100 (k_1 a + F)/H + K_2 R + O_c$$

where

AC = Average cost (\$/kWh)

k_1 = Capital cost (\$/kW)

a = Annual capital charge rate (\$/yr)

F = Fixed O&M costs (\$/yr)

K_2 = Fuel cost (\$/Btu)

R = Heat rate (Btu/kWh)

H = Utilization factor (hrs/yr)

O_c = Variable operation and maintenance costs (\$/kWh)

The minimum average cost as a function of annual hours of use consists of segments of the average cost curves for the various plant types. Thus, a particular type of plant is the most economical plant to use for loads which have annual durations in the period where its annual average cost curve is the minimum from among those available. A simple example for three plant types is shown in Figure E.2.

The generation expansion plan is calculated for three planning horizons: ten years, five years, and two and one-half years. The ten-year horizon corresponds to the lead time for large fossil fuel plants, and the two and one-half year horizon corresponds to the lead time required for small fossil fuel peaking plants.

Loads are forecasted for each of the horizon years. The projected plant mix is also determined for each horizon year, taking into account currently existing plants, plants scheduled to come on-line, and plants scheduled to be retired. The difference between the generation capability of the projected plant mix and the forecasted load is made up by scheduling new construction in such a way as to minimize the expected cost of generation.

Once plants have been built, their construction and other fixed costs are sunk costs, thus the variable costs become the determining factor for the cost of production. The demand for energy is met by using the units in order of operating cost to satisfy the demand for electric energy.

Transmission and distribution costs are calculated on the basis of empirical equations based on historical relationships. The quantities estimated are structure miles of transmission, pole miles of primary distribution capability, substation capacity at the transmission level, and at the distribution level, line transformer capacity, and the number of meters. Each

or these quantities is specified as an empirical function of characteristics related to the service area, such as number and nature of customers, load density, and so forth. Operation and maintenance costs for transmission and distribution are treated similarly.

Demand Submodel

The demand model consists of a set of demand equations for electricity, oil, natural gas, and coal for two sectors: residential, commercial, and industrial. These equations were estimated using cross sectional data for 49 states for the period 1968-1972. The fossil fuel prices are specified exogenously, but electrically, prices are determined endogenously. Thus, the possibility of shifting end-use demands among the different energy forms exists. Since the electricity price also depends in part on fossil fuel prices, this mechanism assures that the estimates of actual electricity consumption are based on a consistent set of fuel prices.

For the residential-commercial sector, the per-capita total energy demand is estimated for each state. The total energy consumption for the state is then obtained by multiplying the projected population. Fuel split equations are used to allocate the total energy demand among the several energy sources. Finally, the state demands are aggregated by region to give regional demands.

The per-capita total energy demand is given by:

$$\log X_{jt} = a_1 + a_2 \cdot X_j + a_3 \cdot T_j + a_4 \cdot P_j + a_5 \cdot D_j + a_6 \cdot \log X_{j, t-1}$$

where the coefficients a_i are empirically determined by regression

X_{jt} = Total energy consumption for the j^{th} state

X_j = Per-capita income for the state

T_j = Minimum temperature for the state

P_j = Weighted energy price for the state

D_j = Population density for the state

The ratio of natural gas and oil demand to the demand for electric energy is given by the "energy split" equations

$$\log (X_G/X_E)_t = a_1 + a_2 \cdot \log (P_G/P_E) + a_3 \cdot T_M$$

$$\log (X_O/X_E)_t = b_1 + b_2 \cdot \log (P_O/P_E) + b_3 \cdot T_L + b_4 \cdot T_M + \log (X_O/X_E)_{t-1}$$

where

X_G = Demand for natural gas

X_E = Demand for electricity

X_O = Demand for oil

P_G = Deflated price of NG in the R-C sector

P_E = Deflated price of electricity in the R-C sector

P_0 = Deflated price of oil in the R-C sector

T_M = Maximum temperature

T_L = Minimum temperature

These quantities are specified for each state. The parameters a_i and b_i are determined by regression.

The industrial energy demands are calculated in a very similar manner, except that total industrial energy demand is estimated on a national basis from a regression relation on the weighted average industrial energy price index for the U.S., and the value added in manufacturing. This energy is then allocated over the states by a set of state industrial "energy split" equations which are functions of population ratio between the state in question and a reference state, and the ratio of industrial energy prices between the two states, plus the logged value of the energy demand ratio estimate.

Regulatory-Financial Submodel

This submodel "closes the loop" by calculating the price of electricity for each region, as a function of the cost of supplying electric energy. This is accomplished by using essentially the same procedure actually used to set the price of electricity. The rate base, a fair rate of return, and the revenue requirement and the total electric energy sold, the price of electricity is determined.

The Rate Base: The rate base (RB) is primarily composed of the net (depreciated) evaluation of the utility's tangible property, comprising plant and equipment used and useful in serving the public, plus an allowance for working capital (W) determined by using a Federal Power Commission (FPC) formula. The value of the utility's tangible property is the sum of capital expenditures for generation, distribution, and transmission equipment at original cost (K) less accumulated depreciation (D).

Capital expenditures for each region are computed and sequentially stored every year within the financial model using values of new capacities and capital costs from the supply model, and transmission and distribution investments from the T&D model. Accumulated depreciation is computed by the straight line method with an assumption of a 40-year average plant and equipment lifetime. The FPC formula for monthly billing companies is used to compute the allowance for working capital whereby the allowance is set equal to one eighth of the annual operation and maintenance expense.

Rate of Return: A key issue in the computation of revenue requirements for a utility is the rate of return on rate base allowed by the regulatory commission. A regulatory commission normally uses a weighted average cost of capital to derive the regulated rate of return.

The model uses an identical approach and endogenously determines the allowed rate of return (r) by keeping track of the capital structure and the cost of capital of individual financing components, thus simulating the process of rate setting by the regulatory bodies.

Revenue Requirements: In addition to meeting a return on the rate base, the gross revenue (R_g) has to cover operation and maintenance costs, taxes, depreciation, and other expenses. Property and income taxes are computed in a manner similar to that used by electric utility companies. A fairly sophisticated

model is used to determine deferred taxes, investment tax credits, and other tax-related variables, with each region treated as an individual utility. The model allows the user to specify a linear combination of normalized accounting and flowthrough accounting. Liberalized depreciation rules are used in the computation of deferred taxes.

The rate base can be expressed as $RB = K - D + W$ where K, D, and W are as defined earlier. Thus, the net revenue allowed by the regulatory commission (R_n^*) is

$$R_n^* = r (K - D + W)$$

where r = allowed rate of return on rate base. Alternatively, the accounting net revenue R_n , can be expressed as

$$R_n = R_g - C_p - d_1 - PT - IT + DT$$

where

R_g = Gross revenue

PT = Property taxes

IT = Income taxes

d_1 = Straight line depreciation expense

DT = Composite allowance for deferred taxes

C_p = Production costs

Income taxes are given by the relation:

$$IT = T_y (R_g - C_p - d_a - I - PT)$$

where

d_a = Depreciation expense using accelerated method for tax purposes

I = Interest expense, and,

T_y = Income tax rate

Equating the allowed net revenue (R_n^*) to the accounting net revenue (R_n) to simulate the regulatory process, and solving for R_g yields:

$$R_g^* = \frac{r (K - D + W) + d_1 - T_y d_a - T_y I - DT}{1 - T_y} + C_p + PT$$

where R_g^* = gross revenue requirements as determined by the regulatory authority.

Financing Requirements: The model also simulates, through a flow of funds analysis, the financing of new plant and equipment. The various financing alternatives that are made available in the model are long-term debt, preferred stock, common stock, and a hypothetical source called the State Power Authority (SPA). The first three sources have limits on the amount of financing each can provide consistent with the "rules-of-thumb" guidelines of prudent financial management. These limits, which are in effect capital constraints, serve to simulate the capital markets in a naive but structurally consistent manner. A hierarchy of financing options is established. Debt, having the highest priority, followed by preferred stock, common stock

and SPA financing, are resorted to in this order, to meet external funding requirements. SPA financing is considered a "lender of last resort" without a limit on the amount it can finance. Its purpose in the model is to quantify the capital shortages utilities might face in financing their expansion through normal capital markets if allowed rates of return are set below the cost of capital.

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APPENDIX (F)

THE BECHTEL ENERGY SUPPLY PLANNING MODEL

This section presents an overview of the methodology and data base for the Energy Supply Planning Model, hereafter called the model. Included are discussions of the function of the model and the methodology used, system boundaries, the energy supply system, information flow in the model, and finally, user interface considerations.

FUNCTION AND METHOD

The function of the model is to provide both the computational tools and the data base necessary to calculate the total direct capital, manpower, and material resources required to bring on-line and to operate the energy supply and transportation facilities required for any specified future energy mix in the 1975 to 1995 time frame. The approach has been to develop a large-scale computerized model of the U.S. energy supply system that can be used as a systematic planning tool to test the impact on direct resource requirements of a variety of future fuel mixes. The intent is to provide information to determine potential bottlenecks in energy supply development programs.

The method emphasizes developing a model that, while dimensionally quite large, is structurally straightforward, proceeding from user-specified assumptions for major variables, and transparent assumptions for other variables, through a series of easily understood submodels to produce resource requirements results. This decomposition into submodels is designed to allow model users a step-by-step specification of decision variables, and in so doing to permit testing the sensitivity of results to these variables.

User access to major decision points within each submodel is deliberately emphasized so that the model results represent information derived from simulation of user decisions rather than a decision-making capability provided by the model. Additionally, flexible exercise of the various user options is easily accommodated. For most user options, there is a capability

to specify user considerations at various levels of detail, making the model suitable for use by energy policy-makers and analysts alike. To allow this flexibility, reference (or default) specifications exist in the model and become operative only when the user chooses not to exercise his prerogative to specify decision variables at all levels of detail.

THE U.S. ENERGY SUPPLY SYSTEM 1975 to 1995

Central to the derivation of resource requirements for any future energy mix is a complete specification of the energy supply system that will provide that energy. Figure F.1 specifies the interactions between the energy supply facilities needed to recover (left-hand side), process, and convert energy resources into forms ready for final consumption (right-hand side). The facilities are linked together by flows of energy; each energy flow path begins with a resource recovery facility (e.g., underground Eastern coal mine) or a port facility (in the case of imports). After recovery, a fuel may be processed (oil refining), converted to other fuels (coal liquefaction, oil gasification), converted to electricity, or used directly (natural gas).

Energy supply technologies are included in the system based on whether or not they are considered likely to make a significant impact on total system-wide resource requirements during the time period of 1975 through 1985. To meet this criterion, a technology must have a significant number of facilities operating by 1995*. Subjective application of this criterion led to the inclusion of the 66 energy supply facilities shown in Figure F.1 and listed in Table F-1, and to the exclusion of those technologies listed in Table F-2.

In addition to the treatment of energy supply facilities described above, the model accounts for energy transportation, transmission, and distribution facilities requirements. Each energy flow shown in Figure F.1 requires some means of transportation to another facility or to final demands. Table F-3 lists the 25 energy transportation facilities included in the energy transportation system.

These 66 energy supply facilities and 25 energy transportation facilities are the essential building blocks around which the computational tools and the facilities data base are developed. The real strength of the model lies in the resulting capability to integrate system-wide requirements for any resource category over a wide spectrum of technologies and industries, so that the impact of changes in energy supply patterns can be readily determined.

The concept of a "nominal" facility is the device used to translate the 91 energy-related facilities into building blocks with certain energy technology and resource requirements (capital, manpower, and materials) characteristics. A nominal facility represents an average facility in that its resource requirements are typical of requirements for facilities of that kind likely to be under construction in the 1975 to 1985 time period. This definition implies that a nominal facility may not be identical to any existing or planned facility, but will yield sufficiently accurate construction resource requirements over the time period. The definition of a nominal facility is static; hence each definition embodies a fixed size and technology.

* With a maximum 10-year engineering and construction lead time, facilities will have to be in operation by 1995 if engineering construction is initiated by 1985.

Table F-1 Energy Supply Facilities Included
in the Energy Supply System

PETROLEUM

Exploration, Development and Production

Onshore oil production - lower 48
Offshore oil production - lower 48
Alaskan oil production

Refining and Processing

High-gasoline refinery
Low-gasoline refinery
Heavy fuel oil gasification
Naphtha gasification
Crude oil stockpile

Other

Alaskan oil export facility
Offshore crude oil import facilities
Onshore oil import facilities

OIL SHALE

Development and Production

Oil shale mine
In-situ shale oil recovery

Refining and Processing

Oil shale retorting and upgrading
Shale oil upgrading

Table F-1 Energy Supply Facilities Included
in the Energy Supply System
(continued)

NATURAL GAS

Exploration, Development and Production

Onshore gas production - lower 48
Offshore gas production - lower 48
Alaskan gas production facilities
Coal mine degasification facilities

Other

Alaskan LNG export facilities
LNG import facilities
Natural gas stockpile

COAL

Development and Production

Underground Eastern coal mine
Surface Eastern coal mine
Surface Western coal mine
Underground Western coal mine

Refining and Processing

Coal gasification (high Btu)
Coal gasification (low and medium Btu)
Coal gasification (methanol)
Coal liquefaction (heavy fuel oil)
Coal solvent refining (SRC)
Coal liquids refinery

Table F-1. Energy Supply Facilities Included
in the Energy Supply System
(continued)

NUCLEAR

Exploration, Development and Production

Surface uranium mine
Underground uranium mine

Refining and Processing

Uranium mill
Uranium conversion
Uranium enrichment - diffusion
LWR fuel fabrication - no plutonium recycle
LWR fuel fabrication - plutonium recycle
HTGR fuel fabrication
FBR fuel fabrication
LWR spent fuel reprocessing
HTGR spent fuel reprocessing
FBR spent fuel reprocessing
High-level waste disposal

ELECTRIC POWER-RELATED FACILITIES

Recovery and Processing

Solid waste collection/separation plant

Electric Generation

Oil-fired power plant
Reconversion of oil-fired plant to high Btu coal
Coal-fired power plant (low-Btu)
Coal-fired power plant (high-Btu)
Coal/solid-waste-fired power plant (low-Btu coal)
Coal/solid-waste-fired power plant (high-Btu coal)
Sulfur oxide removal facilities
Low/intermediate Btu gas-fired plant
High Btu gas-fired power plant
Combined cycle power plant

Table F-1 Energy Supply Facilities Included
in the Energy Supply System
(continued)

Gas turbine power plant
Fuel cells
Light water reactor (LWR)
High temperature gas reactor (HTGR)
Fast breeder reactor (LMFBR)
Dam and hydroelectric power plant
Pumped storage
Geothermal power complex
 OTHER FACILITIES
Solar space heating
Solar space conditioning
 TOTAL
66 Facilities

Table F-2 Energy Supply Facilities Excluded
from the Energy Supply System

Fusion reactors
Advanced topping cycles (includes MHD)
Bottoming cycles
Solar-electric conversion technologies, including indirect sources, wind power, tidal power, and ocean thermal gradients
Advanced battery systems
Flywheels
Compressed air storage
Hydrogen as an energy carrier
Thermionic converters
Thermoelectric generators
Conversion of bio-mass to synthetic fuels
In-situ conversion of coal
Superconducting power transmission facilities
Thorium mines
Gas-cooled fast breeder reactor
Domestic tar sand
Power plant waste heat use systems
Local energy use facilities, including nuclear and fossil industrial process heat, industrial power plants, residential furnaces, etc.

Table F-3 Energy Transportation System Facilities

PETROLEUM	COAL
<u>Transportation</u>	Rail line
Crude oil pipeline - lower 48	Coal train
Alaskan oil pipeline	Coal barge
Products pipeline	Coal truck
Hot oil pipeline	Coal slurry pipeline
Oil tanker	Coal slurry preparation
Oil barge	Coal slurry dewatering
Oil tank truck	
<u>Distribution</u>	
Refined products bulk station	
NATURAL GAS	ELECTRIC POWER-RELATED FACILITIES
<u>Transportation</u>	<u>Transmission</u>
Gas pipeline - lower 48	Overhead transmission lines
Alaskan gas pipeline	230 kV AC
LNG tanker	345 kV AC
	500 kV AC
<u>Distribution</u>	765 kV AC
Gas distribution facilities	400 kV DC
	<u>Distribution</u>
	Electricity distribution facilities
TOTAL = 25 Facilities

Figure E.2 Average Costs of Production

SYSTEM BOUNDARIES

It is important to define the system boundaries for any analysis before undertaking the effort, and it is impossible for the observer to interpret the results of any analysis without a clear understanding of these system boundaries. In the model, system boundaries of two kinds are most significant: the energy supply system boundary and the resource requirements accounting system boundary.

Figure F.2 indicates the boundaries for the energy supply system (the reader may also refer to Figure F.1). As shown, accounting of supply activities begins with the initiation of private company involvement in the exploration process. Preliminary survey work done by government agencies is excluded. Included in the scope of the analysis are resource recovery, processing, conversion, transportation, and local distribution activities. On the other end of the supply system, distribution to the consumer meter is included for natural gas and electricity. However, distribution activities for oil are carried only to the local product bulk station (particularly, service stations are excluded). Also, all activities associated with using "final" fuels are excluded; this includes on-site industrial boilers or power plants, residential furnaces, air conditioners, home appliances, etc.

For each nominal energy facility (both energy supply and energy transport) included in the model, certain categories of capital, manpower, and material resource requirements have been developed. This is referred to as the data base. While a complete description of the accounting system used and the categories of resource requirements employed will be given in Section 6 of this report, a few general statements describing the boundaries of items included are warranted.

Resource requirements have been developed both for the engineering and construction of facilities and for their operation during their lifetime.

Briefly, resource requirements data are gathered for the direct costs of construction of a facility (exclusive of owner's costs such as for site acquisition and interest during construction), as well as for the direct costs of operating and maintaining each facility. All costs are expressed in third-quarter 1974 constant dollars and are given in two-digit Bureau of Economic Analysis categories (e.g., primary iron and steel products, BEA 37). Indirect costs are excluded: for example, the data base includes the purchase cost and installation requirements for a boiler in a power plant but not the (indirect) costs associated with the manufacture of the boiler. R&D costs associated with the development of new technologies are also excluded.

To complement the categories of capital costs described above, a list of selected major materials and equipment has been developed. This list contains selected major items deemed essential to the construction of energy facilities (structural steel, turbo-generators, etc.), and is significant in identifying possible constraints stemming from shortages in basic material supplies or in production capacity for major equipment.

In addition to various cost categories, resource requirements for the major engineering disciplines, designers and draftsmen, supervisors and managers; and those of major skilled craftsmen (pipefitters, electricians, etc.) as well as teamsters and laborers have been included.

INFORMATION FLOW IN THE MODEL

The Energy Supply Planning Model converts future energy mixes to facilities and attendant resource requirements schedules. A simplified overview of the methodology for accomplishing this objective is indicated in Figure F.2, and a summary of the highlights of the information flow through the model follows.

Fuel Mix Generator

The user chooses a candidate future energy mix of interest, typically for the years 1975 or 1977, 1980, 1985, and 1990; or he may specify the mix for only one future year, leaving the time dependence to extrapolation schemes internal to the model. He may also specify the future mix at various levels of fuel detail, depending upon his interests (e.g., total demand for crude oil products versus fraction of crude oil supplied by oil shale versus fraction of oil shale produced by in-site recovery facilities). In this case, missing input variables are supplied by reference (or default) variables that have been generated by the study team. The Fuel Mix Generator then converts the user or reference input variables to a complete specification of 251 annual energy flows for the years 1973 to 1995. Essentially, each flow line on Figure F.1 is quantified annually in this manner.

National and Regional Energy Facilities Generators

The Energy Facilities Generators calculate, based on the annual energy flows from the Fuel Mix Generator, the annual schedules of energy supply facilities of various types needed on-line, both in the nation and in each region, to supply the proposed fuel mix. New facilities are defined as ones additional to those existing 1 January 1974. The calculations of national schedules for the 66 energy facilities take into account:

- Existing facilities
- Retirements
- Planned capacity
- Nominal facility descriptions (size, conversion efficiency, etc.)

Once the schedules of new additions are determined at the national level, and at user option, these requirements are regionalized into a 14-region geographic breakdown of the United States as illustrated in Figure F.4. The 14 regions include 11 onshore and 3 offshore regions. All onshore region boundaries coincide with state boundaries and are similar to U.S. Census Bureau regions; the seven eastern-most regions are identical to Census regions.

The regional schedule of energy supply facilities is computed by applying user (or default) energy facility location coefficients to the previously calculated national facility schedules. The energy facility location coefficients specify the fraction of additional facilities of the various types that are to be located in each of the 14 regions as a function of time. (For example, locate new offshore oil production facilities entirely in the Gulf Coast region for the 1974 to the 1979 period and, thereafter, 25 percent in the Atlantic Coastal region, 25 percent in the Gulf Coastal region, and 50 percent in the Pacific Coastal region). The output of the Energy Facilities Generators is a schedule of required facilities for each of 66 types in each of 14 regions for the years 1974 to 1995.

Inter-regional Fuel Allocation and Transportation Facilities Generator

The Fuel Allocation and Transportation Facilities Generator, based on the distribution of energy supply facilities over the 14 regions of the United States, allocates fuel derived from the facilities to the demand of the 11 onshore regions, and calculates energy transportation facility requirements necessary to effect this distribution. The calculation takes into account user (or default) values for:

- Regional demand coefficients
- Inter-regional fuel flow rules
- Inter-regional transportation modal split coefficients

The inputs for regional demand coefficients simply specify the fraction of national final fuel demands that accrue to each of the 11 onshore regions, e.g., 0.125 of demand for motor gasoline in Northeast region, 0.086 in Mid-Atlantic region, etc.

The inputs for fuel flow rules specify a set of priority supply regions for each demand region, by fuel type. Intra-regional supplies are used first; next, user preferred supply regions outside of the demand region are searched, then less favorable regions, and finally, fuel from any supply region is accepted. For example, a typical user (or default) input might instruct the model to look first to regions 2, 3, and 5 for supplying unsatisfied coal demand in region 4, then to regions 6, 8, and 9, and finally to any region with excess supply.

The inputs for transportation modal split coefficients specify the fraction of a given flow of fuel that is to be transported from one region to another by each candidate mode. These fractions are applied to growth in fuel flows rather than to total flows; e.g., for new flows to crude oil from the Gulf Coastal region to the Mid-Atlantic region, send one-half of new flows by crude oil pipeline, one-quarter by oil tank truck, and one-half by oil tanker.

The output of the Inter-regional Fuel Allocation and Transportation Facilities Generator is a schedule of required energy transportation facilities for each of 25 types over each inter-regional link (as well as apportioned to the regions) for the years 1974 to 1990.

National/Regional Resource Requirements Generators

The Resource Requirements Generators specify, based on the annual schedule of facilities required to be on-line and on the facility resources data base existing for each facility, the annual requirements of capital, manpower, materials, and equipment for:

- Energy supply or transportation facilities
- Construction or the normal operation and maintenance of facilities
- Each facility or the whole energy system
- Each region or the whole country

Major inputs to the Resource Requirements Generators are the facility schedules described previously and facility resources data (discussed extensively in Section 6). If only national resource results are of interest, the regional calculations in Figure F.3 may be bypassed.

Outputs from the Resource Requirements Generators comprise annual resource requirements for the years 1974 to 1985 for:

- Up to 115 construction resource categories*
- Up to 115 operations resource categories*
- 66 energy supply facilities
- 25 energy transportation facilities
- 14 regions

USER INTERFACE CONSIDERATIONS

The dimensions of the outputs of each of the four major submodels shown in Figure F.3 are summarized in Figure F.5. Not all of this information needs to be produced by a single run. The model is designed with a view toward providing users with a high degree of flexibility in the types of information produced by a given run and in the level of detail necessary for specifying input variables. This design is motivated by the belief that few users will find it significant to specify input variables at a level of detail necessary to control all the outputs. The following paragraphs summarize the major user input and output options available.

Selection of Resource Requirement Outputs

One type of user option pertains to selection of resource requirement outputs of interest. The user may specify that he wishes resource results only for:

- Certain facility types
- Certain resource category groupings

For facility-type selection, the user may specify exactly which combination of the 66 individual supply facilities and the 25 individual transportation facilities are to be included in the calculation of resource requirements. Additionally, he may specify whether the results are to be printed out by facility or merely as the summation over all facilities.

For resource category groupings, the user may select any combination of the following construction requirement groupings for output:

- Manpower (man-years)
- Capital, materials, and equipment (dollars)
- Selected major materials and equipment (physical units)

In addition, he may select any combination of the following operations requirement groupings:

- Manpower (man-years)
- Materials, equipment and utilities (dollars)
- Natural resources consumption (physical units)

* Current model data base includes data for 77 construction resource categories and 55 operations resource categories.

Figure F-1 The Bechtel Energy Supply Planning Model

EXPLORATION, DEVELOPMENT		RECOVERY, CONVERSION, PROCESSING, PRODUCTION	TRANSPORTATION	LOCAL DISTRIBUTION	USE			
GOV'T	PRIVATE							
EX- CLUDED	INCLUDED IN MODEL				EXCLUDED			

Figure F.2 Energy Supply System Boundary

Figure F.3 The Energy Supply Planning Model: Methodology Overview, Inputs and Outputs

1. NORTHEAST	8. NORTHERN MOUNTAIN
2. MID-ATLANTIC	9. SOUTHERN MOUNTAIN
3. SOUTH ATLANTIC	10. NORTHERN PACIFIC (INCL. ALASKA)
4. EAST NORTH CENTRAL	11. SOUTHERN PACIFIC (INCL. HAWAII)
5. EAST SOUTH CENTRAL	12. ATLANTIC COASTAL
6. WEST NORTH CENTRAL	13. GULF COASTAL
7. WEST SOUTH CENTRAL	14. PACIFIC COASTAL

Figure F.4 Model Regions

● FUEL MIX:	251 FUEL FLOWS 23 YEARS, ANNUALLY 1973-1995
● ENERGY FACILITIES SCHEDULE:	66 FACILITIES 14 REGIONS 22 YEARS, ANNUALLY 1974-1995
● TRANSPORTATION FACILITIES SCHEDULE:	25 FACILITIES 165 INTERREGIONAL LINKS 17 YEARS, ANNUALLY 1974-1990
● RESOURCE REQUIREMENTS SCHEDULES:	115 CONSTRUCTION RESOURCE CATEGORIES 115 OPERATION RESOURCE CATEGORIES 91 FACILITIES 14 REGIONS 12 YEARS, ANNUALLY 1974-1985

Figure F.5 Basic Model Dimensions

Figure F.6 Regional Output Options

Selection of Regional Outputs

The second type of user option pertains to specifying the degree of regional analysis to be carried out. Three basic options are presented in Figure F.6 and are summarized below:

- National analysis of all facilities
- Regional analysis of energy supply facilities
- Regional analysis of energy supply and transportation facilities

The associated user input variables necessary for implementing the three regional facility analysis options are indicated in Table F-4.

Table F-4 Input and Output Structure for Regional Facility Output Options

User Specified Input Variables	Output Options		
	National Facilities	Regional Energy Supply Facilities	Regional Energy Supply and Transportation Facilities
Future fuel mix	X	X	X
Energy facility location coefficients		X	X
Regional demand coefficients			X
Inter-regional fuel flow rules			X
Inter-regional transportation modal split coefficients			X

As can be seen, a national analysis of all facilities requires only that the user specify the future fuel mix. For a regional analysis of energy supply facilities, user (or default) input variables for the energy facility location coefficients must be specified as well. For a regional analysis of energy supply and transportation facilities, all user (or default) input variables must be specified. For the user interested in the minimum specification of input variables and the maximum amount of regional analysis, internal default values for most of the fuel mix variables and for all of the regional input variables may be employed. However, in this case, the resulting outputs will simulate user interests correspondingly less well. A more accurate reflection of user interests can be gained by specifying at least the most significant input variables.

REFERENCES

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2. Gallagher, J.M. and R.G.J. Zimmermann, "Coal in Transition," Prepared for Energy Modeling Forum, Bechtel National, Inc., February 1978.

APPENDICES
OF
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APPENDIX A

BESOM MODEL

Notation Description

The following description of BESOM uses the notation employed by Brookhaven in their model documentation. The notation uses a "class reference" system. The system is described by Brookhaven as follows: A CLASS consists of two parts: a class name and the members, e.g.,

CLASS E Energy
 O Oil
 G Gas
 C Coal

Here, E is the class name and O, G, C are the members. (E) is used to refer to all members of Class E. The construct D(E) produces the following names: DO, DG, DC. Two or more classes can be used in one construct. For example, given

CLASS DM Demand
 SH Space heating
 AC Air conditioning,

the construct (E)TO(DM) produces the six names

OTOSH, OTOAC, GTOSH, GTOAC, CTOSH, CTOAC.

Finally, the expression

$$\sum_{E,DM} (E)TO(DM) = 100 \text{ means}$$

$$OTOSH + OTOAC + GTOSH + GTOAC + CTOSH + CTOAC = 100$$

CONSTRAINT SET DETAIL

1. Supply Constraints

The resource supply constraints limit the use of the resources to their availabilities. In BESOM, resource availabilities vary with the costs of supplying the resources. Because linear approximations of the supply curves or cost functions (9-step functions) define the cost/quantity relationship, the step functions specify the maximum quantity which would be supplied at each price. BESOM treats the resource supplied at each cost as a distinct resource, that is, each resource is treated as nine distinct resources in the linear program. Nine equations enter the constraint set which limit the resource usage at each cost, $RR(RSi)$, to the length of the associated step, $LG(RSi)$. The nine constraint equations take the form

$$RR(RSi) \leq LG(RSi)$$

and the balance equation for total usage of the resource, $RR(RS)$, is

$$\sum_{i=1}^9 RR(RSi) - RR(RS) = 0$$

2. Simple Processing Constraints

In BESOM, resource supply refers to the resource before processing. The first step in the energy system flow is the simple conversion of the resource into possible intermediate energy forms, $RS(IEF)$. Process efficiency factors, SPE , for the cleaning, transportation, and refining of the resource into each possible intermediate energy form, adjust the Btu content

of the resource to the Btu content of the intermediate energy form. The simple conversion process for each resource is represented in the constraint set as

$$RR(RS) - \sum_{(IEF)} \frac{1}{SPE_{(RS),(IEF)}} * (RS)(IEF) = 0$$

3. Demand Constraints

The demand constraints require that the given level of end-use demands be met. Intermediate energy forms and end-use devices satisfy end-use demands at various efficiencies. These efficiency relationships are accounted for in the demand constraints. The Btu content of each intermediate energy form is related to the Btu content of an end-use demand through an end-use efficiency factor, $EUE_{(IEF)(D)(DM)}$, which is particular to the intermediate energy form, (IEF) , end-use device, (D) , and end-use demand, (DM) , combination. The demand constraint requires that the Btu sum of all intermediate energy forms used by all end-use devices to satisfy an end-use demand, $(IEF)(D)(DM)$, adjusted by end-use conversion efficiencies, must equal the specified demand level, (DM) . The constraint equation for each end-use demand takes the form

$$\sum_{(IEF)(D)} EUE_{(IEF)(D)(DM)} * (IEF)(D)(DM) = (DM)$$

4. Environmental Constraints

The environmental constraints limit the total impact for each environmental effect, (POL) , and each pollution emission, (RAD) , considered in BESOM to fall within specified limits, $UP(POL)$, $UP(RAD)$. Environmental effects and pollution emissions are associated with each activity as energy is converted from resource supply to end use. The usage of a resource $RR(RS)$, the conversion of a resource into an intermediate energy form $RS(IEF)$, the conversion of an intermediate energy form by an electric generating plant, $FF(IEF)(EL)$, and the end-use conversion of an intermediate energy form by an end-use device are all associated with environmental impacts. The total impacts for each (POL) and (RAD) are limited in constraint equations in the form

$$\begin{aligned} & \sum_{(RS)} ENV(POL)_{(RS)} * RR(RS) + \sum_{(RS),(IEF)} ENV(POL)_{(RS),(IEF)} * (RS)(IEF) \\ & + \sum_{(IEF),(EL)} ENV(POL)_{(IEF),(EL)} * FF(IEF)(EL) \\ & + \sum_{(D),(IEF),(DM)} ENV(POL)_{(D),(IEF),(DM)} * D(IEF)(DM) \leq UP(POL) \end{aligned}$$

An analogous constraint is entered for each pollution emission (RAD) .

5. Market Penetration Constraints

Market penetration constraints limit various activity levels in the energy system. The constraints are required at times in BESOM because the linear programming specification does not reflect increased processing costs or reduced efficiencies with higher levels of activity. All technologies are linear outside of

the resource supply. Inputs and outputs are in a fixed relation, regardless of the level of production. As a consequence, particular optimal activity levels, if left unconstrained, may be unrealistically high. In such cases, constraints on the levels of some activities have been imposed.

6. The Electricity Sector Constraints

Eight sets of equations are included below which describe the detailed electricity sector of the model.

a. Fuel to Electricity Conversion

For each electric generating plant (EL), there is a constraint equation which relates the Btu content of the fuel inputs to the plant $FF(IEF)$, to the Btu content of the electricity generated by the plant, $EE(EL)$, through the conversion efficiency factor $CE(IEF)(EL)$. The efficiency factor is particular to the plant/fuel combination. The electricity generating technology of each plant is summarized by the relation

$$\sum_{(IEF)} CE(IEF)(EL) * FF(IEF)(EL) - EE(EL) = 0$$

b. Fuel to Waste Heat Conversion

A subset of electricity generating plant types considered in BESOM have the capability of generating waste heat. These plants are in the central station/district heating, (DH), and decentralized devices, (DD), categories. For each of these plants, a constraint equation is included for waste heat as well as electricity conversion. The fuel input to the plant is related to the waste heat output of the plant, $WHE(DH)$ or $WHE(DD)$, through the efficiency factor $WCE(IEF)(DH)$ or $WCE(IEF)(DD)$. The constraint equation summarizing the waste heat conversion technology is analogous to the above constraint for electricity conversion,

$$\sum_{(IEF)} WCE(IEF)(DH) * FF(IEF)(DH) - WHE(DH) = 0$$

c. Electricity and Waste Heat Transmission

The transmission constraints balance the electricity generated by a plant with the electricity (after transmission but before end-use conversion) cited to meet end-use demands. A similar balance is made for waste heat. A portion of the generation by central station plants is lost in transmission on route to satisfying end-use demands. This is not so for decentralized devices since the device is located at the site of the user. Hence, the generation/demand balance depends upon the generating plant type.

For decentralized devices, (DD), the generation, $EE(DD)$, $WHE(DD)$, to demand, $N(DD)(DM)$, $H(DD)(DM)$ balance is one-to-one and the balance constraint is

$$EE(DD) - \sum_{(DM)} N(DD)(DM) = 0$$

$$WHE(DD) - \sum_{(DM)} H(DD)(DM) = 0$$

For central station plants, electricity and waste heat generation, $EE(CD)$, balances with the electricity transmitted to meet demands, $N(CD)(DM)$, after adjusting for transmission losses. The electricity cited for all end-use demands except storage demand, $DM=04$, is adjusted by the transmission efficiency factor, $TE(CD)$, which can vary

by plant. The balance equation for each central station plant incorporates transmission technology as follows:

$$EE(CD) - \frac{1}{TE(CD)} * \sum_{\substack{(DM) \\ DM \neq 04}} N(CD)(DM) - N(CD)04 = 0$$

The transmission efficiency for waste heat is $TWE(DH)$ and the equation for each central station/district heating plant, (DH), which balances generation, $WHE(DH)$, and demand, $H(DH)(DM)$, is as follows:

$$WHE(DH) - \frac{1}{TWE(DH)} * \sum_{(DM)} H(DH)(DM) = 0$$

d. Storage Conversions

Delivering electricity to pumped storage and battery storage and converting fuels to electricity by electrolytic process involve energy losses. The conversion efficiency factor, $CEBS$, relates the electricity delivered to battery storage, $TELE07$, to the electricity generated from battery storage, $EEBS$, as follows:

$$TELE07 - \frac{1}{CEBS} * EEBS = 0$$

In meeting the demand for pumped storage and electrolysis, $TELE04$, the electricity generated from pumped storage, $EE14$, is adjusted by a conversion efficiency factor, $EEPS$, and the fuel input to the electrolytic process, $ES(IEF)$, is adjusted by a process efficiency factor, PEE . The constraint equation imposing this technological relation is:

$$TELE04 - \frac{1}{EEPS} * EE14 - \frac{1}{PEE} * ES(IEF) = 0$$

e. Electricity Deliveries, Primary versus Backup

Each generating plant delivers electricity to meet primary or backup electricity demands. $X(EL)(DM)$ refers to deliveries cited for primary demands while $B(EL)(DM)$ and $K(CD)(DM)$ refer to deliveries to unreliable decentralized devices and central station plants for back up. The following constraints assure that (1) deliveries for backup meet backup demands and; (2) total deliveries meet total demands.

1. The backup electricity demands by unreliable central station plants, $TELE24$, and decentralized devices, $TELE23$, are two of the three end-use demand categories whose demand levels are determined within the optimization model. Backup demands are based upon the amount of electricity which is generated by the unreliable plants (i.e., $EE(DD)$ and $EE(CD)$ by unreliable plants, DD and CD) and an exogenously specified fractions, $a(EL)$. The

fraction $a_{(EL)}$ defines the proportion of the electricity demand to be met by the backup for the unreliable generating plant. In other words, for the unreliable generating plant (EL), generating electricity, $EE(EL)$.

$$a_{(EL)} = \frac{\text{electricity met by backup}}{EE(EL) + \text{electricity met by backup}}$$

which implies

$$\text{electricity met by backup} = \frac{a_{(EL)}}{1-a_{(EL)}} * EE(EL)$$

The constraint equation which determines the total backup demand by all unreliable decentralized devices, TELE23, is then

$$\text{TELE23} - \sum_{\substack{(DD) \\ \text{unreliable}}} \frac{a_{(DD)}}{(1-a_{(DD)})} * EE(DD) = 0$$

where the fraction $a_{(DD)}$ is particular to the decentralized device (DD).

The constraint equation which derives the total backup demand by all unreliable central station plants, TELE24, incorporates an additional transmission efficiency factor, TE, to account for electricity losses incurred while transmitting the electricity to the unreliable central stations

$$\text{TELE24} - TE * \sum_{\substack{(CD) \\ \text{unreliable}}} \frac{a_{(CD)}}{(1-a_{(CD)})} * EE(CD) = 0$$

Constraint equations are also included to assure that the amount of backup electricity delivered from all plants equals the total backup demand requirement. For $B(EL)(DM)$ - the electricity delivered to unreliable decentralized devices by generating plant (EL) to meet demand (DM)-and $K(CD)(DM)$ -the electricity delivered to unreliable central station plant by central station plant (CD) to meet demand (DM)-, the balance constraints are

$$\sum_{\substack{(EL),(DM) \\ \text{daily on-peak}}} B(EL)(DM) - \text{TELE23} = 0$$

$$\sum_{\substack{(CD),(DM) \\ \text{daily on-peak}}} K(CD)(DM) - \text{TELE24} = 0$$

2. For electricity deliveries from each central station plant to meet demand, the following form is true:

$$\sum_{(DM)} N(CD)(DM) = \sum_{(DM)} \left[X(CD)(DM) + B(CD)(DM) + K(CD)(CM) \right]$$

and from each decentralized device,

$$\sum_{(DM)} N(DD)(DM) = \sum_{(DM)} \left[X(DD)(DM) + B(DD)(DM) \right]$$

f. Electricity Demands, Peak versus Off-Peak

Total electricity delivered by all generating plants to meet the peak and the off-peak portion of each demand must balance with electricity used by all end-use devices to satisfy the demand.

The constraint for each demand DM (except 03) is expressed as follows:

$$\sum_{(EL)} \left[g_{(DM)} * X(EL)(DM) + g_{B(DM)} * (B(EL)(DM) + K(CD)(DM)) \right] + \sum_{(EL)} \left[X(EL)(DM) + B(EL)(DM) + K(CD)(DM) \right] - \sum_{(D)} (D) ELE(DM) = 0$$

In this constraint, the first term corresponds with the peak portion of the demand, the second term corresponds to the intermediate or base load portion of demand, and the third term is the total demand.

The peak load proportion of demand, TELE03, is the third endogenously determined end-use demand in BESUM. The peak demand is based upon the electricity generated at the primary load factor, $X(EL)(DM)$, and electricity generated at the backup load factor, $B(EL)(DM)$ and $K(CD)(DM)$, for each daily on-peak demand (i.e., the on-peak portion of electricity demanded for end use DM) and the demand's associated peak fraction (g or g_B). (A definition and discussion of g , the peak fraction, is contained in Section I.) The constraint equation which defines peak load demand is

$$\text{TELE03} - \left[\sum_{\substack{(DM),(EL) \\ \text{daily on-peak} \\ \text{except 03}}} g_{(DM)} * X(EL)(DM) + \sum_{\substack{(DM),(EL) \\ \text{daily on-peak} \\ \text{except 03}}} g_{B(DM)} * (K(EL)(DM) + B(EL)(DM)) \right] = 0$$

NOTE 1:
$$\sum_{\substack{(DM),(EL) \\ \text{except 03}}} \left[X(EL)(DM) + K(EL)(DM) + B(EL)(DM) \right]$$

is analogous to the Y_i variable in the illustration in Section I which explains the peak fraction. TELE03 is analogous to X_i and

$$\sum_{(DM),(EL)} \left[X(EL)(DM) + K(EL)(DM) + B(EL)(DM) \right]$$

is analogous to E_i .

NOTE 2: In the constraint equation, daily off-peak demands are not included in the summations. Since the value of the peak fraction for off-peak demands is zero, however, it is not necessary to make this distinction.

An additional peaking constraint is required for each decentralized device. Since electricity generated by decentralized devices is not transmitted, they must satisfy their own peak demands. The constraint is to assure that the peak load demand served by each decentralized device equals the electricity delivered by the plant to meet the peak, $X(DD)03 + B(DD)03$.

$$\sum_{\substack{(DM) \\ \text{daily on-peak} \\ \text{except } 03}} g_{(DM)} * X(DD)(DM) + \sum_{\substack{(DM) \\ \text{daily on-peak} \\ \text{except } 03}} gB_{(DM)}$$

$$* B(DD)(DM) - X(DD)03 - B(DD)03 = 0$$

g. Generating Capacity Requirements

Electricity generating capacity requirements are determined by the amount of electricity being delivered to meet the daily on-peak demands and the load factors associated with these demands. The following example has been included to illustrate how capacity requirements are determined for the simplified case of one generating plant and one end-use demand. The actual constraints which determine capacity requirements for plants serving multi demands are then given.

Suppose a plant generates electricity to satisfy one daily on-peak demand, XELDM, and the load factor associated with the demand is LF. Assuming no transmission losses or reserve margin requirements, plant capacity must be at least as great as XELDM/LF. If electricity is lost in transmission and the transmission efficiency factor is TE, the minimum capacity level would be XELDM/(LF*TE). And if a reserve margin requirement RM is also specified, the minimum capacity level is increased to $(1 + RM) * XELDM / (LF * TE)$.

Included in the constraint set is an equation for each type of generating plant which puts a lower bound on the generating capacity based on the above technique. For central station plants, capacity, YY(CD), is determined as follows:

$$YY(CD) - \left[\sum_{\substack{(DM) \\ \text{on-peak}}} (1 + RM) / (LF_{(DM)}) * TE * X(CD)(DM) + \sum_{\substack{(DM) \\ \text{on-peak}}} (1 + RM) / (LF_{B(DM)}) * TE * \left[K(CD)(DM) + (CD)(DM) \right] \right] \geq 0$$

where $LF_{(DM)}$ is the primary load factor particular to the demand and $LF_{B(DM)}$ is the backup load

factor which is also particular to the demand.

Decentralized devices need not adjust their generation requirements or their capacity to cover transmission losses, since the electricity generated by these plants is not transmitted. The constraint for these devices, YY(DD), is then

$$YY(DD) - \left[\sum_{\substack{(DM) \\ \text{on-peak}}} (1 + RM) / LF_{(DM)} * X(DD)(DM) + \sum_{\substack{(DM) \\ \text{on-peak}}} (1 + RM) / LF_{B(DM)} * B(DD)(DM) \right] \geq 0$$

The capacity required for district heating plants, YY(DH), and for decentralized devices, YY(DD), to meet waste heat demands is determined in an analogous manner.

$$YY(DH) - \left[\sum_{\substack{(DM) \\ \text{on-peak}}} (1 + RM) / (LF_{(DM)}) * TE * H(DH)(DM) \right] \geq 0$$

$$YY(DD) - \left[\sum_{\substack{(DM) \\ \text{on-peak}}} (1 + RM) / LF_{(DM)} * H(DD)(DM) \right] \geq 0$$

h. Off-Peak Generation

For each plant there is an associated plant factor, PF, which is the ratio of usable capacity (after taking downtime into consideration) to total capacity.

A constraint equation is entered for each plant, which limits the amount of electricity generation from the plant based on the plant capacity and plant factor.

$$EE(EL) \leq PF * YY(EL)$$

Similarly, waste heat generation from each plant is limited by the plant capacity and by the waste heat plant factor for the plant, PFH.

$$WHE(EL) \leq PFH * YY(EL)$$

The amount of electricity which can be delivered to meet daily off-peak demands at each plant is limited by the plant's usable capacity and the amount of electricity which is being delivered to meet daily on-peak demands. The following explains the derivation of the constraint equations which limit electricity deliveries to meet daily off-peak demands.

If a plant serves one on-peak demand with load factor less than its plant factor, it is not generating as much electricity as it could, and some capacity is available for off-peak power generation. Let X_1 be the electricity generated by the plant, let PF be the plant factor, and let LF_1 be the demand's load factor. Then total installed capacity is $\frac{X_1}{LF_1}$ and usable capacity is $PF * \frac{X_1}{LF_1}$.

If $PF > LF$, then $(PF * \frac{X_1}{LF_1} - X_1)$, which represents the additional electricity which could be generated by the plant, is positive. This is the capacity available to satisfy off-peak demand.

In BESOM, the total installed capacity for each plant is derived by 1) dividing the electricity delivered to meet each daily on-peak demand by the demand's load factor and 2) summing overall daily on-peak demands. The usable capacity is then determined by multiplying the installed capacity by the plant factor, and the generating capacity available to meet daily off-peak demands is determined by subtraction. The constraint is as follows:

$$\sum_{\substack{(DM) \\ \text{off-peak}}} X(EL)(DM) - \left[\sum_{\substack{(DM) \\ \text{on-peak}}} \left(\frac{PF(EL)}{LF(DM)} - 1 \right) * X(EL)(DM) \right. \\ \left. + \sum_{\substack{(DM) \\ \text{on-peak}}} \left(\frac{PF(DM)}{LF_B(DM)} - 1 \right) * (K(EL)(DM) + B(EL)(DM)) \right] \leq 0$$

Seasonal off-peak generation is limited by the amount of capacity installed to meet the seasonal peak. Another example will be used to explain the derivation of the equation constraining seasonal off-peak demand by each plant:

If a plant generates X_{on} units of electricity to meet seasonal on-peak demand with seasonal load factor LF_{on} , installed capacity equals $\frac{X_{on}}{LF_{on}}$. If the

load factor on the seasonal off-peak demand is LF_{off} , the maximum electricity which could be generated to meet seasonal off-peak demand is determined by multiplying its load factor by total installed capacity, $LF_{off} * X_{on}/LF_{on}$.

In BESOM, there is one seasonal on-peak demand, air conditioning (16), and one seasonal off-peak demand, space heat (14). The form of the equation which constrains the seasonal off-peak demand met by each generating plant is as follows:

$$X(EL) 14 + B(EL) 14 \leq \frac{LF_{off}}{LF_{on}} * X(EL) 16 + \frac{LF_{off} B}{LF_{on} B}$$

where LF_{off} , LF_{on} , and $LF_{off} B$, $LF_{on} B$ refer to the primary and backup load factors, respectively.

OBJECTIVE FUNCTION DETAIL

Extraction costs (ext.), fuel delivery costs (fuel c.), processing costs (proc.), end-use device costs (end.), capital recovery costs (cap.) and operating and maintenance costs (osm.) are the costs entries to the objective function associated with the energy activities.

The extraction cost of a resource increases with increased usage of a resource. For each resource, nine entries are made in the objective function equal to the height of each step in the resource supply function times the usage of the resource at that cost. The objective function entries are of the form $ext_i * RR(RS_i)$, where ext_i is the cost for step i and $RR(RS_i)$ is the usage at step i .

Fuel delivery costs include transportation costs, tariffs, or taxes on each intermediate energy form used by electric generating plants or by end-use devices in satisfying end-use demands. The costs enter the objective function as

$$\text{fuel c} * (FF(IEF)(EL) + (D)(IEF)(DM)).$$

Simple processing costs are associated with the conversion of extracted or imported energy resources into intermediate energy forms. End-use device costs are associated with the costs of the end-use devices which convert intermediate energy forms into energy end uses. The objective function entries are

$$\text{end} * UN(D)(IEF)(DM)$$

$$\text{proc} * (RS)(IEF).$$

The capital recovery cost for each plant, $CAP(EL)$, enters the objective function multiplied by the generating capacity of the plant. The capital recovery costs associate an annualized dollar value with the plant capacity based upon the cost of the plant, the plant lifetime, and a fixed charge rate. The capital recovery cost is derived as follows. First, the cost of the plant in dollars per kilowatt, $Y(EL)$, is annualized using the capital recovery factor for the plant, $CRF(EL)$. Second, the annualized cost is adjusted by a capacity utilization factor, $UJF(EL)$, which depends on the load factor of the demands served by the plant. For central station plants, the capital recovery cost is also adjusted upward by a transmission loss efficiency factor, TE .

The capital recovery cost in \$/million Btu is calculated as

$$CAP(EL) = \frac{Y(EL) * CRF(EL) * 10^6}{3413 * 8760 * UJF(EL)} * \frac{1}{TE}$$

The capital recovery factor is calculated based upon a specified fixed charge rate, $FCR(EL)$, of the plant as follows:

$$CRF(EL) = \frac{FCR(EL)}{1 - (1 + FCR(EL))^{-LT}}$$

The objective function entry for generating plant capital cost is

$$CAP(EL) * YY(EL).$$

The operation and maintenance costs for each generation plant, osm , are assumed to vary directly with the level of electricity generation of the plant. The objective function entry is

$$osm * EE(EL).$$

APPENDIX B

THE GULF-SRI ENERGY MODEL

I. Simple Conversion Process

A simple conversion process models the technology and economics behind the production of an intermediate energy product from an energy feedstock. The feedstock can be a primary resource or another intermediate energy product. The physical relations of the process determine the energy feedstock and secondary material requirements and the capacity and capacity additions associated with the level of process operation. The behavioral relations of the process determine the intermediate product price.

The inputs to the physical relations of the process are:

1. the level of intermediate energy product production determined higher in the network, $q(t)$
2. the exogenous projection for the thermal efficiency of the process, $e(t)$
3. the exogenous projection for the average lifetime of a unit of capacity, L
4. lagged values for capacity and capacity additions, $C(t-1)$, $C_a(t-L)$
5. the present value of the capital cost determined in the behavioral relations of the process, $k(t)$
6. the exogenous projections for the secondary material requirement per unit of capital cost for all secondary materials, $S_j(t)$, $j = 1, \dots, J$

In the physical relations of the process, capacity replacement for depreciation $C_r(t)$, is equated to the capacity additions made L years previously, $C_a(t-L)$. The current level of capacity, $C(t)$, is equated to last period's capacity less depreciation or to this period's current production, $q(t)$, whichever is larger. This implies the level of capacity additions for the period, $C_a(t)$.

The secondary material requirements associated with new capacity additions, $W_j(t)$, $j = 1, \dots, J$, vary directly with the cost of capital, $k(t)$. That is, increasing the capital cost by Δk units increases the secondary demand requirement per unit of new capacity by $\Delta k \cdot S$ units. The feedstock requirement, $q_f(t)$, is related to product production through the thermal efficiency factor.

The physical relations for the simple conversion process are summarized as follows:

1. $C_r(t) = C_a(t-L)$
2. $C(t) = \max(q(t), C(t-1) - C_r(t))$
3. $C_a(t) = C(t) - C(t-1) + C_r(t)$
4. $W_j(t) = C_a(t) \cdot k(t) \cdot S_j(t)$; $j = 1, \dots, J$
5. $q_f(t) = q(t) \cdot \frac{1}{e(t)}$

The inputs to the behavioral relations of a simple conversion process which determine product price are:

1. all future prices and the variable costs of the product, $P(n)$, $VOC(n)$ for $n = t+1, t+2, \dots$
2. the energy feedstock price and normalized secondary material prices derived from processes lower in the network, $P_f(t)$, $\pi_j(t)$ $j = 1, \dots, J$

3. exogenous projection for the process thermal efficiency factor, $e(t)$
4. exogenous value for the present value of capital cost in the base year, $k(0)$
5. exogenous projections for the inflation rate, the average lifetime of a unit of capacity, discount rate, technological change parameters, operating costs, secondary material costs weights and tax parameters

In the behavioral relations of the simple conversion process, products are priced using a present value analysis. The analysis assumes that investors have perfect knowledge of future prices but that they cannot instantaneously adjust their operations to these prices. Hence, the product price determined in an equilibrium solution of the model is a short run equilibrium price.

The product price in each period is set equal to the variable cost of production plus the return on the capital used in the production of the product. The return can imply above- or below-normal profits in any given period. It is calculated based upon the long run equilibrium, normal profit return, with an upward adjustment for industries experiencing rapid growth or a downward adjustment for industries with excess capacity. The long run equilibrium return, at the margin, is calculated as the present value of the capital facility (the "user" cost at which the capital facility could be bought or sold) less the present discounted value of all future cash flows. The adjustment factor applied to the long run equilibrium return is calculated based upon the product's demand growth. The behavioral relations which derive the product price and each of its components are presented below.

In long run equilibrium, the present value of a capital facility in the current period equals the present value of the cash flow, after taxes, across the book life of the capital facility

$$k(t) = (1 - f_{\text{tax}}) \sum_{n=t}^{t+L} \frac{P(n) - VOC(n)}{(1+r)^{n-t}}$$

where

$k(t)$ = present value of the capital facility (cost) in period t

f_{tax} = income tax rate

L = average lifetime of the facility

$P(n)$ = product price in period n ; $n = t, t+1, \dots, t+L$

$VOC(n)$ = variable cost in period n ; $n = t, t+1, \dots, t+L$

r = discount rate

and

$$\frac{P(n) - VOC(n)}{(1+r)^{n-t}} = \text{present discounted value in period } t \text{ of the cash flow in period } n; n = t, t+1, \dots, t+L$$

Solving the above expression for the product price in period t , $P(t)$, defines the current period product price to be equal to the variable cost in period t plus the after-tax difference between the present value of the capital cost and the discounted future cash flows from the capital facility. This difference is termed the capital charge in period t .

$$P(t) = \underbrace{VOC(t)}_{\text{variable cost}} + \underbrace{\frac{k(t)}{1-f_{\text{tax}}} - \sum_{n=t+1}^{t+L} \frac{P(n) - VOC(n)}{(1+r)^{n-t}}}_{\text{capital charge}}$$

To allow for above- or below-normal profits in the short run, the capital charge component is multiplied by a rapid growth/excess capacity multiplier, $l(t)$. The multiplier increases the return on capital and hence, product price, during periods of rapid growth and reduces the return during periods of excess capacity or slow growth. The behavioral relation used to calculate the product price in the simple conversion process is as follows:

$$P(t) = VOC(t) + \left[\frac{k(t)}{1-f_{\text{tax}}} - \sum_{n=t+1}^{t+L} \frac{P(n) - VOC(n)}{(1+r)^{n-t}} \right] * l(t)$$

The derivation of variable cost, $VOC(t)$, the present value of the capital cost, $k(t)$, and the rapid growth/excess capacity multiplier, $l(t)$, will be discussed in order.

Variable Cost

Variable cost is calculated from the energy feedstock price, $P_f(t)$, derived in a process lower in the network, the thermal efficiency factor, $e(t)$, and the operating cost per unit of output, $V(t)$. The calculation is as follows:

$$VOC(t) = \frac{1}{e(t)} * P_f(t) + V(t)$$

Present Value of the Capital Cost

The present value of the capital cost is derived from an estimate of the capital cost in some base year, $k(0)$. This base year cost is adjusted over time to account for the changes in the capital cost due to a) technological change b) inflation and c) changes in secondary material costs. The resulting time series for the capital cost represents the nominal price of the capital facility. Investment tax credits, tax depreciation allowances and finance charges cause the "user" cost of capital to differ from the nominal price. A final adjustment is made to account for changes in the user cost of capital due to d) tax policy and financing.

- a) **Technological Change Adjustment**—A given technology is associated with a commercial availability date, t_a . The capital cost, $k(0)$, is adjusted upward if the technology is used prior to commercial availability and downward for use after commercial availability. The adjustment is described by a learning curve as follows:

$$k_1(t) = k(0) * f_c$$

$$= k(0) * \left[\begin{array}{l} P_e^{(t_a - t)} \\ f_{\infty} + (1 - f_{\infty})(1 - P_c)^{(t - t_a)} \end{array} \right] \begin{array}{l} t < t_a \\ t \geq t_a \end{array}$$

where

P_e = technological change rate prior to commercial availability

P_c = technological change rate after commercial availability

f_{∞} = the fraction which relates the capital cost after full adjustment to the technological change, to the base value for the capital cost.

- b) **Inflation Adjustment**—The model is specified in current dollar terms. Capital costs are converted from constant dollars, $k_1(t)$, to current dollars, $k_2(t)$ as follows:

$$k_2(t) = k_1(t) * f_i \\ = k_1(t) * (1 + r_{\text{inf}})^t$$

where r_{inf} is an exogenously specified inflation rate.

- c) **Secondary Material Cost Adjustment**—The current dollar capital cost is a summation of secondary material costs. The fraction of the capital cost allocated to each secondary material j , $j = 1, \dots, J$ is defined as S_j

where

$$\sum_{j=1}^J S_j = 1$$

The capital cost, $k_2(t)$, is adjusted for changes in a secondary material price based upon the fraction of the total cost it represents and the movement in the secondary price relative to its base value, $\pi_j(t)$. This latter value is calculated in the behavior relations of the secondary material process. The secondary material cost adjustment is made as follows:

$$k_3(t) = \sum_{j=1}^J k_2(t) * S_j * \pi_j(t)$$

- d) **Tax Policy and Financing Adjustments**—Investment tax credits or tax depreciation allowances reduce the actual cost of a capital facility to the user below the purchase price of the capital facility while finance charges increase the cost. Adjustments are made to capital cost, $k_3(t)$, to derive the "user" cost of capital, $k(t)$, actually employed in the price equation of the simple conversion process.

The tax policy adjustments are modeled after Jorgenson's "user cost of capital" calculation. For the financing cost adjustment, the model assumes the expenditure is financed over one-third of the construction interval. The current dollar cost of capital is adjusted upward by the real rate of inflation.

$$k(t) = k_3(t) * (1 - \text{RITC}) * (1 - \text{RTDA}) * \left(\frac{1+r}{1+r_{\text{inf}}} \right)^{t_c/3}$$

where

RITC = investment tax credit rate

$$\begin{aligned} \text{RTDA} &= \text{tax depreciation allowance adjustment} \\ &= \frac{2}{\text{TL}} f_{\text{tax}} / \left(1 - \left(1 - \frac{2}{\text{TL}} \right) / (1 + r) \right) \end{aligned}$$

f_{tax} = income tax rate

r = interest rate

r_{inf} = inflation rate

t_c = construction interval

TL = tax life

Rapid Growth/Excess Capacity Multiplier

The rapid growth/excess capacity multiplier, $l(t)$, is a short run price adjustment to allow for above- or below-normal profits during periods of abnormal demand growth. The multiplier adjusts the capital charge component of price upward during periods when an industry is expanding rapidly to meet increased demand growth. Alternatively, prices are adjusted downward during periods of slow growth. An industry's growth rate is measured by capacity additions, $C_a(t)$ relative to capacity, $C(t)$. If capacity additions are positive, the industry is growing and the multiplier is calculated as

$$l(t) = 1 + \frac{C_a(t)}{C(t)} * P_g \quad C_a(t) > 0$$

where P_g is an exogenous parameter describing the sensitivity of price to the capacity growth rate. When capacity additions are zero, the growth multiplier is replaced by an excess capacity multiplier which is related to the gap between capacity, $C(t)$, and production, $q(t)$, as follows

$$l(t) = \max \left(0, \frac{C(t) - q(t)}{C(t)} \right) \quad C_a(t) = 0$$

2. Primary Resource Process

The physical relations of a primary resource process determine the level of cumulative, committed production, the capacity and capacity additions associated with the current production level and the secondary material requirements of the process. The behavioral relations determine the price of the primary resource. A primary resource process is modeled similarly to a simple conversion process. Unique to the modeling of primary

resource production are the concept of cumulative, committed production, the resource supply curve, depletion of the resource and the economic rent component of the resource price.

The input requirements of the physical relations are:

1. the level of current resource production derived higher in the network, $q(t)$,
2. the exogenous projection for the average lifetime of a unit of capacity, L ,
3. lagged values of cumulative, committed production, capacity, and capacity additions, $Q(t-1)$, $C(t-1)$, $C_a(t-L)$,
4. the exogenous projection for the quantity of secondary materials required per unit of marginal costs, and
5. the marginal cost of production calculated in the behavioral relations of the process, $m(t)$.

In the physical relations, capacity replacement for depletion, $C_r(t)$, is equated to the capacity additions made L years previously, $C_a(t-L)$. The current level of capacity, $C(t)$, is equated either to last period's capacity less depletion or to this period's current production, whichever is larger. This implies the level of capacity additions for the period, $C_a(t)$. Cumulative, committed production, $Q(t)$, then follows from its value in the previous period plus the value of new capacity additions multiplied times the average lifetime of the capacity. The secondary material requirements associated with the new capacity additions, $W(t)$, vary directly with the marginal cost of current production, $m(t)$. In the model, increasing marginal cost by Δm units increases the secondary demand requirement per unit of new capacity by $\Delta m * S$ units. The physical relations can be summarized as follows:

$$C_r(t) = C_a(t-L)$$

$$C(t) = \max(q(t), C(t-1) - C_r(t))$$

$$C_a(t) = C(t) - C(t-1) + C_r(t)$$

$$Q(t) = Q(t-1) + C_a(t) * L$$

$$W(t) = C_a(t) * m(t) * S$$

The inputs to the behavioral relations of a primary resource process are:

1. the level of cumulative, committed production of the resource calculated by the physical relations of the process,
2. the exogenously specified long run supply curve for the resource which defines the marginal cost associated with each level of cumulative, committed production,
3. all future prices and marginal costs of the resource,
4. exogenous projections for the inflation rate, the rate of technological change, and the time preference rate, and
5. the ratio of the current price for secondary materials to the base price, $\pi(t)$, derived in the secondary material process.

The behavioral relations of a primary resource process determine the price of a resource as the sum of the marginal cost of production and an economic rent factor, adjusted for

short run supply phenomena. The resource price is calculated in four steps. First, the constant dollar, constant technology marginal cost of the resource, $m(t)$, is derived from the long run supply curve for the resource and the level of cumulative, committed production.

$$(1) \quad m(t) = m(Q(t))$$

Since all long run marginal cost curves were formulated based upon the technology and the currency values for the initial period, costs are adjusted by a multiplicative inflation factor, $f_i(t)$, and a technological change factor, $f_c(t)$. (The derivation of these factors is the same as in the simple conversion process, described above.) This produces a current dollar marginal cost for the resource which also reflects the current year's technology, $m(t)$.

$$(2) \quad m(t) = m(t) * f_i(t) * f_c(t)$$

The third step involves computing the economic rent component of the resource price. An economic rent term, which prices a resource above its marginal cost, is included if a higher return (discounted to the current period) could be realized by postponing production. The economic rent is calculated as the maximum, over all future time periods, of the present discounted value of the resource's price, $P(t)$, less its marginal cost, $m(t)$. The price/cost difference is discounted by the exogenously specified time preference rate, r .

$$\hat{P}(t) = m(t) + \max_{n \geq t} \frac{P(n) - m(n)}{(1+r)^{n-t}}$$

The fourth step involves adjusting the price, $P(t)$, to account for short run supply phenomena. Both a secondary material cost multiplier, $\pi(t)$, and a rapid growth/excess capacity multiplier, $l(t)$, are employed as in the simple conversion process. (The derivations of the multipliers for the two processes are the same. The secondary material cost adjustment in the primary resource process is simplified because all the factors of production in this process are treated as a single secondary material.) The final behavioral relation calculating price in the primary resource process is

$$(4) \quad P(t) = \hat{P}(t) * \pi(t) * l(t)$$

3. Transportation Process

A transportation process models the economics of transporting a primary resource or a converted energy form to a refinery region or a demand region. A transportation process is identical to a simple conversion process with a fixed distance for the transportation link. The process feedstock is an energy form before transport and the process product is the energy form after transport. Capital, in the form of terminals, trains, pipelines, etc., is required to operate the process. The proportion of energy lost in transport is analogous to the thermal efficiency factor in the simple conversion price.

The input requirements for the relations of the transportation process include all of the inputs required for a simple conversion process plus:

1. the distance of the transportation link, and
2. the exogenous fractions a_k , a_v , and a_e , which represent the fraction of the capital cost, operating cost, and efficiency loss, respectively, of the

transportation process which is independent of the transport distance.

The physical and behavioral relations of the simple conversion process form the basis for the transportation process relations. Starting from the simple conversion process relations, adjustments are made to the capital cost component of product price, $k(t)$, the operating cost component of price, $V(t)$, and the thermal efficiency factor, $e(t)$, to account for the length of the transportation link. The adjustments to the capital cost take the form

$$k(t) = k_o(t) * \left[a_k - (1 - a_k) \frac{d}{d_o} \right]$$

where $k_o(t)$ is the capital cost for transporting the energy form over a distance, d_o , d is the distance over the actual transportation link and a_k is the fraction of the capital cost which is independent of the transport distance (i.e., the fixed portion of the capital cost).

Operating costs and the thermal efficiency factor are adjusted similarly

$$V(t) = V_o(t) * \left[a_v - (1 - a_v) \frac{d}{d_o} \right]$$

$$e(t) = e_o(t) * \left[a_e - (1 - a_e) \frac{d}{d_o} \right]$$

where $V_o(t)$, $e_o(t)$, a_v , and a_e are defined analogously to the above.

4. Allocation Process

An allocation process models each intermediate energy product's market share of a demand. The process can be viewed as allocating a demand across the competing sources of supply. The behavioral relations of the process derive:

1. the static market shares for each energy source satisfying a particular demand based upon the relative prices of the energy sources,
2. the price of the demand.

The physical relations of the process

1. divide the demand into new and existing demand,
2. derive dynamic market shares for new and existing demand based upon the static market share calculations for total demand and behavioral lag coefficients, and
3. balance the sum of the dynamic market shares with the total demand.

The use of dynamic versus static market shares to allocate demands allows the equilibrium solution to reflect a short run situation with a "less than optimal" demand configuration. That is, while a certain set of energy prices dictates an optimal energy demand mix, it may not be possible in the short run to alter the energy using capital stock to be compatible with this mix. In such a case, the optimal energy demand would not be the demand expressed in the market. Instead, a "less than optimal" demand mix would exist in short run equilibrium.

The inputs to the behavioral relations of the allocation process are:

1. the price of each competing energy source calculated lower in the network, $P_j(t)$, $j = 1, \dots, J$,
2. exogenous price penalties (premiums) for energy sources which are less (more) desirable means of satisfying the demand, $\delta_j(t)$, $j = 1, \dots, J$,
3. the exogenous market share parameter, γ ,
4. the level of the demand being allocated derived by the physical relations on a downward solve of the model, $q(t)$, and
5. the dynamic market shares of the demand calculated in the physical relations, $q_j(t)$, $j = 1, \dots, J$

The behavioral relations of the process derive a static market demand share approximation for each competing energy form independently of the other energy forms. The approximations are then normalized to assure that the demand allocations sum to the total demand.

The static market share for energy form j , $\hat{q}_j^s(t)$, is modeled as an inverse function of the energy's price, $P_j(t)$, plus a price penalty/premium, $\delta_j(t)$. The price penalty or premium is to reflect quality differences across the competing energy forms which are not reflected in their relative prices. A penalty, or increase in price, is applied to energy forms that are less desirable means of satisfying the demand. Alternatively, a price premium, or reduction in price, is applied to the more desirable energy forms. The behavioral relations are of the form

$$\hat{q}_j^s(t) = (P_j(t) + \delta_j(t))^{-\gamma} \quad j = 1, \dots, J$$

where the parameter γ specifies the sensitivity of the allocation process to the adjusted price. A larger value for γ increases the price sensitivity of the demand allocation, causing demands to fluctuate more when prices are changed.

The static market shares are then normalized such that their sum equals the total demand being allocated $q(t)$. The normalized factor is calculated as the ratio of demand to the sum of the static market shares before normalization

$$q_j^s(t) = \hat{q}_j^s(t) * \frac{q(t)}{\sum_{j=1}^J \hat{q}_j^s(t)}$$

The inputs to the physical relations of an allocation process are:

1. the level of the demand being allocated in the process derived higher in the network, $q(t)$,
2. the lagged value of the demand, $q(t-1)$,
3. the static market shares calculated in the behavioral relations of the allocation process, $q_j^s(t)$, $j = j, \dots, J$, and
4. the exogenous behavioral lag parameters for new and existing demands, B_n, B_e .

The dynamic market share allocations for a demand are derived under the assumption that decision makers would like to observe the demand allocations implied by the static market shares but, due to rigidities in the system, they can only partially adjust toward these demands. The speed of the adjustment process depends upon the proportion of the demand

which is new versus existing demand and the behavioral lags associated with these two classifications.

Existing demand, $q^e(t)$, is equated to the minimum of the current period's demand and the previous period's demand. New demand, $q^n(t)$, is then calculated as the difference between the current and the existing demand

$$q^e(t) = \min(q(t), q(t-1))$$

$$q^n(t) = q(t) - q^e(t)$$

A behavioral lag coefficient B with a value between zero and one defines the weighting scheme B and $(1-B)$. The dynamic allocation of demand is derived by weighting each static market share allocation, $q_j^s(t)$, and the lagged value of the dynamic market share allocation, $q_j(t-1)$, by B and $(1-B)$, respectively. The closer the value of B is to one, the faster is the dynamic adjustment toward the static demand allocation.

The physical relations derive the dynamic market shares for both new and existing demand, $q_j^n(t)$ and $q_j^e(t)$, respectively, by

1. dividing the dynamic demand allocation, $q_j(t)$, between new and existing demand using the total demand proportions

$$\frac{q_j^n(t)}{q(t)}, \frac{q_j^e(t)}{q(t)}$$

2. using unique behavioral lag coefficients for new and existing demands, B_n and B_e , as follows (typically, the behavioral lag coefficient for new demand is greater)

$$q_j^n(t) = \frac{q_j^n(t)}{q(t)} * \left[B_n q_j^s(t) + (1 - B_n) q_j(t-1) \right]$$

$$q_j^e(t) = \frac{q_j^e(t)}{q(t)} * \left[B_e q_j^s(t) + (1 - B_e) q_j^e(t-1) \right]$$

The dynamic demand allocation or market share for each competing energy form, $q_j(t)$, $j = 1, \dots, J$, is then defined as the sum of new and existing dynamic demands,

$$q_j(t) = q_j^n(t) + q_j^e(t)$$

And finally, balance equations are included in the physical relations to assure the sum of all the dynamic demand allocations equals the total demand, $q(t)$

$$\sum_{j=1}^J q_j(t) = q(t)$$

5. End-Use Demand Process

An end-use demand process determines end-use demand based upon exogenous economic activity projections and the price of the energy end use. The physical relation of the process derives a reference end-use demand (at reference energy prices) which fluctuates with economic activity. The behavioral relation of the process adjusts the reference demand in response to price changes.

The input requirements of the physical relation are

- 1) the exogenous economic projections of regional gross national product and population GNP(t), POP(t), and
- 2) the exogenous projections for the relations between GNP and population, a(t) and b(t).

Reference end-use demand, $q(t)$, in a region is expressed as a function of regional gross national product, GNP(t), and population, POP(t).

$$q_0(t) = a(t) * GNP(t) + b(t) * POP(t)$$

where a(t) and b(t) are exogenous, variable coefficients.

Input requirements to the behavioral relations of the end-use process are:

1. the average end-use demand price calculated by an allocation process lower in the network, $P(t)$,
2. the reference end-use demand price, $P_0(t)$,
3. the reference end-use demand calculated by the physical relation of the process, both current and lagged value, $q_0(t)$, $q_0(t-1)$,
4. the lagged value of the end-use demand, $q(t-1)$, and
5. exogenously determined short run price elasticity of demand and lag adjustment parameter, V_s , λ ,

The behavioral relation of the end-use demand process model is calculated by adjusting the reference demand for movements in price, $P(t)$, relative to the reference price, $P_0(t)$, with a behavioral lag

$$q(t) = q_0(t) * \left[\frac{P(t)}{P_0(t)} \right]^{V_s} * \left[\frac{q(t-1)}{q_0(t-1)} \right]^{\lambda}$$

V_s is the short run price elasticity, λ is the lag parameter and $V_s/(1-\lambda)$ defines the long run price elasticity.

APPENDIX C

THE DRI ENERGY MODEL

Model Input Requirements

1. National Economic Projections

Consumer and wholesale price indexes
GNP deflators
Total population
Disposable personal income
Commercial employment
Industrial production indexes
Retail sales of new passenger cars
Housing stock, starts
Mobile homes, shipments

2. Regional Population Projections

3. Oil Prices

Exogenous inputs

Price of imported crude oil
Wellhead price of lower-tier domestic crude oil
Wellhead price of upper-tier domestic crude oil
Average U.S. and Alaskan transportation costs
Markups (above the refiner's average acquisition crude oil price) for residual fuel, distillate fuel, kerosine, and gasoline

Policy assumptions

Crude oil equalization taxes
Industrial and electric utility user taxes
Gasoline taxes
Pricing of Alaskan, enhanced recovery, and stripper oil

4. Oil Supplies

Exogenous inputs

Option 1:

Alaskan North Slope production
Enhanced-recovery oil production
Rates of change in production of lower-tier domestic oil, upper-tier domestic oil and stripper oil

Option 2:

Price elasticities of supply for domestic oil production by source

Policy assumptions

Petroleum imports are unconstrained

5. Natural Gas Prices

Policy assumptions

Natural gas pricing
Industrial and electric utility user taxes

6. Natural Gas Supplies

Exogenous inputs

Option 1:

Rates of change in production of natural gas in the nine supply regions

Option 2:

Price elasticity of supply for domestic natural gas production

Allocation of the production in each supply region to the intrastate and inter-state markets

Alaskan natural gas "imports"
Mexican and Canadian natural gas imports
Quantities of synthetic natural gas (SNG) and liquified natural gas (LNG)
Transportation matrices which allocate the various natural gas supplies to the demand regions

7. Coal Prices and Coal Supplies (determined endogenously but highly sensitive to the following)

Exogenous inputs

Regional Btu content of coal
Scrubbing costs
Transportation costs
Rate of change in scrubbing costs
Rate of change in transportation costs
Rate of change in mining machinery and equipment
Rate of change in wages of coal miners
Strip mining productivity
Deep mining productivity
Percent of strip-mined coal reserve base which can be recovered
Percent of deep-mined coal reserve base which can be recovered
Rate of return on equity
Scrubbing effectiveness

Policy assumptions

Regional sulfur emission standards
Regional reclamation costs for strip mining
Federal and state taxes on deep-mined coal
Federal and state taxes on strip-mined coal

8. Electricity Prices and Supplies (determined endogenously but highly sensitive to the following)

Exogenous inputs

Regional nuclear plant capacities and utilization rates

- Regional hydropower plant capacities and utilization rates
- Regional coal, oil, and natural gas plant capacities
- Rate of return on electricity rate base
- Regional natural gas demands by utilities for peaking purposes
- Regional electricity generation to demand ratios
- Nuclear fuel costs

Policy assumptions

- The proportion of natural gas availabilities (available after demands by higher priority users are met) allocated to electric utilities

9. Residential Energy Using Capital—Saturation Rates and Average Energy Usage

Exogenous Inputs

- Electrically heated homes
- Natural gas heated homes
- Electric water heaters
- Natural gas water heaters
- Centrally air-conditioned homes - electric
- Centrally air-conditioned homes - natural gas
- Home freezers
- Room air conditioners
- Electric ranges
- Washers (automatic)
- Washers (conventional)
- Electric dryers

APPENDICES
OF
The University of Texas at Austin

Appendix A

The SRI-Gulf Model

A.1 General

The SRI-Gulf model is a detailed representation of the entire United States energy system from extraction to end-use. It provides a partial equilibrium solution of regionalized prices and quantities for various intermediate and final energy products in each of seventeen time periods covering the years 1975-2025. Three import regions, eleven resource regions, six refinery regions, and eight demand regions are specified as indicated in Figure A.1. and Table A.1.

Marginal costs taken from long run supply curves are used in conjunction with economic rent calculations to provide primary resource prices.

Demand curves for seventeen final energy usages are adjusted through time by a simple macroeconomic driver that models population growth and aggregate economic activity.

The SRI-Gulf model was developed in 1973 by Edward G. Cazalet and the Stanford Research Institute to analyze synthetic fuels strategy for Gulf Oil Corporation. Versions of the model have subsequently been used in energy analyses sponsored by the U.S. government, the Electric Power Research Institute, and several private entities. The authors refer to the current version as the SRI National Energy Model.

A.2 Methodology

The Gulf-SRI model recognizes the energy system as a collection of distinct physical and behavioral processes that are interrelated in a

Figure A.1

U.S. ENERGY MODEL -- RESOURCE, REFINERY, AND DEMAND REGIONS

Table A.1

DEMAND, REFINERY, AND RESOURCE REGIONS

RESOURCE REGIONS

- 14 Powder River Coal
- 16 Southern Illinois/Western Kentucky Coal
- 17 Appalachia Coal
- 20 South Alaska Oil and Gas
- 23 Midcontinent Oil and Gas
- 24 Pacific Coast Oil and Gas
- 25 Atlantic Offshore Oil and Gas
- 26 West Texas Oil and Gas
- 27 North Slope Oil and Gas
- 28 Rocky Mountain Coal, Oil, and Gas
- 30 Gulf Coast Oil and Gas
- 32 Point of origin for imported fossil fuels
- 59 Point of origin for nuclear fuels
- 70 Secondary material location

DEMAND REGIONS

- 1 New England
- 2 Middle Atlantic
- 3 South Atlantic
- 4 East South Central
- 5 East North Central
- 6 West South Central
- 7 West North Central
- 8 West Coast

REFINERY REGIONS

- 9 Philadelphia
- 10 Gulf Coast Port
- 11 West Coast Port
- 12 Chicago
- 13 South East Port
- 18 West North Central

definite manner. The authors use the following classification for describing processes:

1. Simple Conversion Processes describe the technology and economics of converting one energy material to another (e.g., synthetic gas from coal and residential space heat from gas).
2. Allocation Processes describe the allocation of demand among competing sources of supply (e.g., allocation of gas demand among alternative sources and space heat demand among alternative furnaces and fuels).
3. Primary Resource Processes describe the depletion and pricing of energy resources (e.g., natural gas and coal).
4. End Use Demand Processes describe the growth in demand for usable energy over time and the effect on demand of changes in prices (e.g., space heat and industrial steam).
5. Transportation Processes describe the technology and economics of moving an energy material from one location to another (e.g., natural gas pipelines and coal unit trains).
6. Complex Conversion Processes (e.g., refineries and electric power generation).
7. Secondary Industry Processes describe the impact on secondary material prices of changes in demand for secondary materials used in construction of new energy facilities (e.g., pressure vessels and surface mining equipment).

Each process is represented by a submodel with its own inputs and outputs. The outputs of each submodel serve as inputs to other submodels

in order to provide the simultaneities of the system. The conceptual framework for the model is a network with the process submodels represented by the nodes and the interconnections among them represented by the arcs. A simplified version of part of such a network is shown in Figure A.2, for illustrative purposes.

Each process submodel is in fact a set of mathematical equations that describe two types of relationships. Physical relationships specify the requirements of capital and raw materials for given levels of the output of the process, and behavioral relationships link product prices and level of output. The equations not only connect the inputs of the process to the outputs, but also retain intertemporal consistency. For example, capital additions and retirements must be cumulated for plant capacities to be properly stated. Also, prices in future years are used in the calculation of economic rent for previous years.

Given the network of processes and sets of relationships for each process, a set of prices and quantities are calculated that satisfy all of the equations for all time periods simultaneously. This is accomplished using an iterative algorithm that is similar to the successive over-relaxation (SOR) method for solving a general system of nonlinear equations. By taking advantage of the network structure of the equations, the SRI-Gulf algorithm converges much more rapidly than the general SOR method. To further enhance convergence, the relaxation coefficients are specific to each equation. An outline of the SRI-Gulf algorithm appears in Figure A.3.

A.3 Electric Utility Representation

The electric utility sector is comprised of a set of processes that represent the different

Source: Reference [9].

Figure A.2

EXAMPLE OF ELEMENTS OF THE ENERGY NETWORK

generation methods, the split of electricity demand into load categories, and the manner in which the demand in each category is divided among plant types. These processes are modeled separately for each demand region although there is a provision for baseload power transfer among regions. Other processes provide important interfaces to the utility sector proper. Transportation processes supply the delivered price of fuel to each region's generation facilities and the final demand processes determine the overall electricity demand in each region.

Figure A.4 describes the portion of the network representing the electricity sector and the interface with the rest of the energy system for each region. Process 34 calculates the demand for electricity in the region. Process 101 splits the demand into load categories. Processes 53, 54, and 55 allocate the demand in each load category among the generation technologies which are modeled in the center horizontal row of the network. The bottom row of processes describe the total regional demand for each fuel transported into the region. In the remainder of this section

we describe the mathematical relationships embodied in each type of process in the electricity sector.

The physical relationship for the demand split process is given by equation A.1:

$$q_j(t) = a_j(t) q(t) \quad j=1,2,3 \quad (A.1)$$

where $q(t)$ is the regional demand for electrical energy in time period t , $a_j(t)$ is the fraction of total energy in load category j , and $q_j(t)$ is the resulting electrical demand in load category j . The behavioral relationship A.2 determines the price of electricity, $p(t)$, given the prices of energy in each load category.

$$p(t) = \sum_{j=1}^3 a_j(t) p_j(t) \quad (A.2)$$

The allocation processes determine the market shares for alternative sources of a product. Equation A.3 insures that the total demand, $q(t)$, for the product is equal to the sum of all of the individual demands.

Figure A.3

DETAILS OF THE ALGORITHM

$$q(t) = \sum_{\text{all } i} d_i(t) \quad (\text{A.3})$$

where $d_i(t)$ is the i th demand for the product.

The total quantity provided by the sources must also equal total demand as required by equation A.4.

$$q(t) = \sum_{\text{all } j} q_j(t) \quad (\text{A.4})$$

where $q_j(t)$ is the quantity provided by the j th source. Before $q_j(t)$ is calculated, the market shares, $\hat{q}_j(t)$, that would result if response to price change were immediate are calculated using equation A.5.

$$\hat{q}_j(t) = q(t) \frac{(p_j + \sigma_j)^{-\alpha}}{\sum_{\text{all } i} (p_i + \sigma_i)^{-\alpha}} \quad (\text{A.5})$$

where p_j is the price for source j , σ_j is a premium added to p_j to reflect inconvenience or other differences between sources, and α is a parameter that reflects the market shares' sensitivity to price differences. If α is high, the market approaches cost minimization behavior; lower values of α reflect the desire for diversity of energy sources, incomplete information of buyers, or other factors besides p_j and σ_j that affect market shares.

However, there are also time lags that prevent the market shares in equation A.5 to be realized.

Figure A.4

DEMAND REGION CONVERSION SECTOR DETAIL

In order to include these it is necessary to divide demand into an existing component, $q^e(t)$ and a new component $q^n(t)$ as in equations A.6 and A.7

$$q^e(t) = \min \{q(t), q(t-1)\} \quad (A.6)$$

$$q^n(t) = q(t) - q^e(t) \quad (A.7)$$

The market shares within each of these categories are then calculated using parameters β_e and β_n that reflect the incomplete adjustment due to time lags from one period to the next for existing and new demand respectively. Equations A.8 and A.9 are used by the model to calculate adjusted market shares in each category and equation A.10 provides the combined market share.

$$q_i^e(t) = q^e(t) \left[\beta_e \frac{\hat{q}_j(t)}{q(t)} + (1-\beta_e) \frac{q_j(t-1)}{q(t)} \right] \quad (A.8)$$

$$q_j^n(t) = q^n(t) \left[\beta_n \frac{\hat{q}_j(t)}{q(t)} + (1-\beta_n) \frac{q_j(t-1)}{q(t)} \right] \quad (A.9)$$

$$q_j(t) = q_j^n(t) + q_j^e(t) \quad (A.10)$$

where the initial market shares $q_j(0)$ are provided as input variables.

The price for the product (assumed to be the same for all users) is then calculated with equation A.11.

$$p_i(t) = \frac{\sum_j p_j(t) q_j(t)}{q(t)} \quad \text{for all } i \quad (A.11)$$

The conversion processes for the generation technologies have a common basic structure; differences among technologies are reflected in the process parameters. The physical relationships for the conversion process are straight-forward. Equation A.12 relates the feedstock quantity $q_f(t)$, to the output energy, $q_i(t)$, for each plant type i that uses the feedstock through the efficiency parameter, m_i .

$$q_f(t) = \sum_{\text{all } i} q_i(t) \frac{1}{m_i} \quad (A.12)$$

The model adds new capacity to match demand and replaces retired capacity if it is required as in equation A.13.

$$c_i(t) = \max \left\{ \frac{q_i(t)}{CF_i(t)}, c(t-1) - c_a(t-L) \right\} \quad (A.13)$$

where $c(t)$ is the capacity in time period t , L is the lifetime of the plant type, CF_i is the capacity factor for technology i , and $c_a(t)$ are the additions to capacity in year t ; thus, $c_a(t-L)$ is the capacity that is being retired in period t . Capacity additions for period t are given by equation A.14.

$$c_a(t) = c(t) - c(t-1) + c_a(t-L) \quad (A.14)$$

A final physical relationship, A.15, keeps track of the demand for factors used to construct new capacity.

$$w_j(t) = c_a(t) \cdot k(t) \cdot s_j \quad (A.15)$$

where $w_j(t)$ is the demand for factor j , $k(t)$ is the capital cost per unit output, and s_j is the per unit requirement for factor j .

The first behavioral relation, A.16 calculates the operating cost $\emptyset(t)$ per unit output.

$$\emptyset(t) = v(t) + p_f(t) \frac{1}{m} \quad (A.16)$$

where $v(t)$ is the per unit operating cost and $p_f(t)$ is the feedstock price. Equation A.17 determines the price per unit output.

$$p(t) = \emptyset(t) + \left[\frac{k_d(t)}{1-f_{\text{tax}}} - \sum_{T=t+1}^{t+L} \frac{p(T) - \emptyset(T)}{(1+r)^{T-t}} \right] \cdot \frac{I(t)}{CF_i(t)} \quad (A.17)$$

$I(t)$ is an adjustment factor reflecting the growth rate of the industry and $k_d(t)$ is the capital cost per unit as provided by equation A.18.

$$k_d(t) =$$

$$\underbrace{(1-f_I)}_{\text{investment tax credit}} \left[\frac{1-\frac{2}{t_L} f_{\text{tax}}}{1-\frac{1}{1+r}} \right] \quad \underbrace{\frac{2}{1-\frac{1}{1+r}}}_{\text{tax credit due to depreciation}} \quad (A.18)$$

$$\underbrace{\left(\frac{1+r}{1+r_{\text{inf}}} \right)^t}_{\text{interest and inflation during construction}} \underbrace{\sum_{\text{all } j} k(t) s_j \pi_j}_{\text{capital costs in all secondary industries.}}$$

where π_j is the price secondary material as provided by the secondary material processes and $k(t)$ is an inflation adjusted capital cost for the conversion technology that is based on a learning curve represented by equation A.19.

$$k(t) = \underbrace{(1+r_{\text{inf}})^t}_{\text{inflation adjustment}} k_0 \left[\begin{array}{l} p_e(t_a - t) \\ F_{\infty} + (1-F_{\infty})(1+p_c)^{t-t_a} \end{array} \right] \quad (A.19)$$

$t < t_a$
 $t \geq t_a$

where t_a is the year for commercial availability, F_{∞} is the lower asymptote for $k(t)$, p_e is the technological change rate prior to commercial availability and p_c is the technological change rate after commercial availability. Similar equations exist for technological change in heat rates.

If the industry is growing, i.e. $c_a(t) > 0$, the growth multiplier, $I(t)$, is given by A.20; if, however, $c_a(t) = 0$, $I(t)$ becomes an excess capacity multiplier and is given by A.21.

(A.20)

$$I(t) = 1 + \frac{c_a(t)}{c(t)} p_g \quad c_a(t) > 0$$

(A.21)

$$I(t) = \max [0, 1 - (c(t) - q(t)/c(t))] p_d \quad c_a(t) = 0$$

where p_g and p_d are the price sensitivities to growth rate and excess capacity.

A.4 Inputs and Outputs

The following variables are passed from the electricity sector to the remainder of the model. When the algorithms terminate they provide the electricity related output of the model.

$p_f(t)$ and $q_f(t)$	price and quantity demanded of each fuel type by region for each period t .
$p_i(t)$ and $q_i(t)$	price and quantity of electricity provided by each generation technology by region.
$\pi_j(t)$ and $w_j(t)$	price and quantity for factor input to generation expansion
$c_j(t)$	capacity built for each technology

The following inputs must be provided by the user:

$a_j(t)$	fraction of energy in each load category
r_{inf}	inflation rate
f_{tax}	income tax rate
f_I	investment tax credit
α	market share sensitivity
β_e, β_n	demand lag adjustment

The following inputs must be provided for each generation technology:

f_0	initial market share
t_a	commercialization date
σ	premium for convenience, etc.
m_0	efficiency at commercialization data
m_e, m_c	efficiency change rate before and after commercialization date
m_{∞}	maximum efficiency
L	plant life
CF	capacity factor

s_i	factor input operating cost
k_0	capital cost at commercialization
p_e, p_c	cost change rate before and after commercialization
F_∞	minimum capital cost
r	industry rate of return
p_g, p_d	price sensitivity to growth rate or excess capacity

A.5 Comment

The major strengths of the SRI-Gulf model are its flexibility and detail. Since each process is independently defined, sectors of interest may be modeled in as much detail as necessary without affecting the structure of the rest of the model. The solution methodology is quite general with little restriction on the type of function represented. The current version of the model contains some 2700 processes and requires from 10 to 60 iterations (depending on the quality of the starting solution) at 1.3 minutes (IBM 370/168) of computer time per iteration and 600,000 bytes of core storage. For a national energy model of this scope, flexibility and detail this is a quite reasonable computational requirement. Although the theoretical convergence of such algorithm is not well understood, the authors claim that it has never failed to converge nor has there ever been any evidence of multiple solutions in several years of application.

The authors point out that the dynamic aspects of the model permit the user to specify the degree of foresight of the economic actors that are modeled. Thus the SRI-Gulf methodology combines the advantages of math programming models (which tend to assume perfect foresight) and simulation models (which assume somewhat myopic behavior).

Certain aspects of the electricity sector seem somewhat unrealistic. In particular, the pricing mechanism does not adequately provide prices in a regulated market such as electricity. In fact, the current version of the model does not recognize regulation in any industry. However, the methodological ground work has been laid for including such considerations in later versions.

The values of the input parameters, particularly the change rates, market sensitivities, price sensitivities, and demand lags, are currently provided by expert opinion. Presumably, for a detailed electricity sector analysis, econometric estimates of these parameters could be obtained.

The Project Independence Evaluation System

B.1 General

The Project Independence Evaluation System forecasts the state of the entire U.S. energy system for target dates at the end of 5- to 15-year planning horizons. Supply curves for energy resources are specified for twelve coal, three shale, thirteen oil, and fourteen gas regions. A linear programming representation of the energy system represents the flow of energy materials from the production of these resources, through transportation links, through conversion activities, and to the nine demand regions shown in Figure B.1. Figure B.2 illustrates this flow. Demand curves for each of ten major end-use energy products in each of the demand regions are provided by an econometrically estimated demand model. As described in the next section, the model computes a static market equilibrium of prices and quantities for the energy system using the supply and demand submodels.

The PIES model was developed to assist the Federal Energy Administration make its Project Independence Report. Subsequently it was employed in the formulation of the Carter administration's National Energy Plan.

In essence PIES consists of three parts: a demand sector, a supply sector, and an equilibrating mechanism that balances supply and demand for final energy products as shown in Figure B.3. The supply (and conversion) sector is a linear programming representation of the system illustrated in Figure B.2 where the total cost of production, transportation, conversion, and delivery is minimized. The demand sector calculates a vector of quantities demanded and a matrix of demand elasticities for final energy products, given a vector of prices and an economic forecast. The equilibrating mechanism takes the vector of quantities and the own-elasticities provided by the demand model and derives step-wise linear approximations to the demand curve for each energy product. The linear program of the supply side is then, in a sense, rewritten to incorporate these demand curve approximations. Solving the resulting LP is equivalent to maximizing the sum of consumer plus producer surplus yielding an equilibrium solution for a competitive energy market. However, this process does not guarantee that the prices assumed in the supply and demand sides are consistent. Therefore, the "shadow" prices (dual variables) of the optimal LP solution are compared to the input prices for the demand model. If these prices are the same within a suitable tolerance, the procedure is terminated; if they are not, an average is taken and reinputted into the

Source: Reference [3]

Figure B.1

ELECTRIC UTILITY AND DEMAND REGIONS

Source: Reference [3]

Figure B.2

FLOW OF MATERIALS

demand model, new demand curve approximations are derived, and the LP is reoptimized. This procedure is repeated until a consistent set of prices and quantities are derived. The mathematical derivation of the method, along with several "ad hoc" procedures for taking into account factors such as utility average cost pricing, appears in the referenced PIES documentation.

B.3 Electric Utility Representation

The regionalized demand, d , provided by the demand model for the target year is broken into base, intermediate, and peak load categories. Each unit of generation capacity is operated in one of three modes according to the category of load to which it is assigned. Equations B.1 ensure that there is sufficient generation in each mode to meet the demand for each load category.

$$a_i (d/.91) = x_i^e + x_i^n \quad \text{for } i=1,2,3 \quad (B.1)$$

where $i=1,2,3$ correspond to the equations for base, intermediate, and peak respectively, a_i is

the fraction of total demand in load category i ($a_1 = .65$, $a_2 = .33$, $a_3 = .02$), and $x_i^e + x_i^n$ is the sum of existing and new generation in mode i . Total regional demand is divided by .91 in equation B.1 to reflect transmission losses. The generation in each load category is linked by prespecified plant capacity factors (CF_{ij} = actual output/rated capacity x 8,760 hrs., for each generation technology, j , and operating mode i) to the available generation capacity in equations B.2 and B.3.

$$x_i^e = \sum_{j \text{ all}} CF_{ij} \times c_{ij}^e \quad (B.2)$$

$$x_i^n = \sum_{j \text{ all}} CF_{ij} \times c_{ij}^n \quad (B.3)$$

where c_{ij}^e and c_{ij}^n are, respectively, the existing and new installed capacities for generation technology j operated in mode i . The existing capacity

Figure B.3

PIES EQUILIBRATING MECHANISM

for a generation technology is the available or planned capacity at present, while the new capacity is planned and constructed between the present and the target year. Equation B.4 insures that the existing capacity assigned to each mode does not exceed current capacity, and equation B.5 keeps track of capacity expansion requirements for each generation technology.

$$\sum_{\text{all } i} c_{ij}^e \leq \text{existing capacity } j \quad (\text{for all technologies } j) \quad (\text{B.4})$$

$$\sum_{\text{all } i} c_{ij}^n - b_j \leq 0 \quad (\text{for all } j) \quad (\text{B.5})$$

where the capacity expansion, b_j , for technology j , might be constrained by a build limit as in equation B.6.

$$b_j \leq \text{build limit } j \quad (\text{for all } j) \quad (\text{B.6})$$

Table B.1 summarizes the generation technologies available in PIES, new plant availability, operating modes permitted and unit capacity factors.

Fuel requirements are determined by equation (B.7) for each fuel type k :

$$F_k = \sum_{\text{all } j} \sum_{\text{all } i} [c_{ij}^e \cdot \text{HR}_{ij}^e \cdot \text{CF}_{ij} + c_{ij}^n \cdot \text{HR}_{ij}^n \cdot \text{CF}_{ij}] \quad (\text{B.7})$$

where F_k is the requirement for fuel type k , HR_{ij}^e and HR_{ij}^n are the heat rates for existing and new plant for technology j in mode i , and all units are consistent.

B.4 Comment

The major advantages of PIES are its broad scope, its calculation of a partial equilibrium involving both supply and demand curves, and its extensive data base. From a representational point of view it has several important disadvantages: it is static and thus the development of the system up to the target year must be assumed; it assumes perfect competition in very regulated industries; and many of its modeling assumptions that critically effect the outcome of its solution

are at best untested. From an operational standpoint, it has other disadvantages: it is extremely costly to run; it requires a number of supporting programs written in various computer languages; and its documentation leaves something to be desired. Thus its usefulness tends to be limited to in-house DOE studies.

Table B.1

PLANT TYPES INCLUDED IN THE PIES ELECTRIC UTILITY MODEL

<u>FOSSIL FUEL PLANTS</u> <u>FUEL TYPE</u>	<u>Plant Operated</u> <u>Using This Fuel</u>	<u>New Plant Permitted</u> <u>to be Built</u>	<u>Operating Modes</u> <u>Permitted</u> (Base-B, Intermediate-I, Peak-P)	<u>Unit Load</u> <u>Factors</u>	<u>Standard</u> <u>Tables</u>
Low-Sulphur, Utility Standard Coal	Coal Fired w/o Scrubbers	Yes	BIP	0.7, 0.16, 0.08	Utilities
High-Sulphur, Utility Standard Coal	Coal Fired w/o Scrubbers (in some regions)	Yes	BIP	"	"
	Coal fired with Scrubbers	Yes	BIP	"	"
	Retrofit Scrubber	Yes	BIP	"	"
	Fuel Gas	Yes	B	0.727	Synthetics
Natural Gas	Gas Turbine	No	P	0.08	Utilities
	Natural Gas Steam Turbines	No	RIP	0.7, 0.16, 0.08	"
Residual	Oil-Fed Steam	Yes	RIP	"	"
Distillate	Simple Cycle	Yes	BIP	"	"
	Combined Cycle	Yes	BIP	"	"
<u>NON-FOSSIL FUEL</u> <u>PLANTS</u>					
Hydro	}	Constrained to capacity already announced for construction	BIP	Historical Load Factor for each Region	
Nuclear			B	0.7	Nuclear
Geothermal	Geysers	}	R	0.8	Gen-Solar
	Brine		B	0.8	"
	Hot Rock		B	0.8	"
	Pressure		NOT IN STANDARD TABLES		
	Other Geothermal and Solar		R	0.8	"
Solar	Biomass	}	B	0.8	"
	Wind		B	0.65	"
	Thermal		B	0.75	"
	Ocean Thermal		B	0.95	"
	Photoelectric		R	0.74	"

Appendix C

ICF National Coal Model

C.1 General

The ICF National Coal Model (NCM) is a detailed linear programming representation of the coal production, transportation and electric utility sectors of the energy system for a given year selected by the user. There are 30 supply regions; 35 demand regions and 6 consumer sectors as listed in Figure C.1. The NCM distinguishes among coal types by Btu content (5 categories) and sulfur content (8 categories). This classification permits a very refined analysis of environmental requirements and heat content in the electric utility sector of the model. Supply curves are provided for each coal type in each supply region and have steps for existing mines as well as new mines. Demand estimates for non-utility coal and electricity in each region are exogenously provided without any internal sensitivity to price.

The NCM was developed by ICF, Inc., to assist the FEA in analyzing coal related questions with short-term, medium term, and long-term implications. It compliments the Project

Independence Evaluation System (PIES) model of the entire U.S. energy system in that its greater resolution can refine the PIES longterm coal forecasts.

C.2 Methodology

The NCM uses a straight-forward linear programming representation of the flow of coal and energy from mines to demand points in order to minimize the total cost of meeting coal and electricity demand. Figure C.1 illustrates the flows that are modeled by the LP. Starting at the left, the supply curves are approximately by step functions. Coal washing activities at the mine site then permit the combination of certain sulfur types. Transportation links then move the coal to 19 "coal piles" that retain the distinction between 3 ranks of coal and 6 sulfur categories. Each of the 35 demand regions is assigned to a coal pile in its vicinity; the intermediate coal piles serve to keep the problem size manageable without oversimplifying the transportation sector. In the demand regions the coal is either directly consumed by the non-utility demand sectors or converted to electricity to meet overall electricity demand as detailed in the next section.

Source: Reference [10].

Figure C.1

NATIONAL COAL MODEL STRUCTURE

Table C.1

NCM SUPPLY/DEMAND REGIONS AND CONSUMER SECTORS

30 NCM SUPPLY REGIONS

Pennsylvania (PA)
 Ohio (OH)
 Maryland (MD)
 West Virginia, north (NV)
 West Virginia, south (SV)
 Virginia (VA)
 Kentucky, east (EK)
 Tennessee (TN)
 Alabama (AL)
 Illinois (IL)
 Indiana (IN)
 Kentucky, west (WK)
 Iowa (IA)
 Missouri (MO)
 Kansas (KS)
 Arkansas (AR)
 Oklahoma (OK)
 Texas (TX)
 North Dakota (ND)
 South Dakota (SD)
 Montana, east (EM)
 Montana, west (WM)
 Wyoming, (WY)
 Colorado, north (CN)
 Colorado, south (CS)
 Utah (UT)
 Arizona (AZ)
 New Mexico (NM)
 Washington (WA)
 Alaska (AK)

6 NCM CONSUMER SECTORS

Coking
 Industrial
 Residential
 Commercial Synthetics
 Export
 Electricity

35 NCM DEMAND REGIONS

Maine/Vermont/New Hampshire (MV)
 Massachusetts/Connecticut/Rhode Island (MC)
 New York, upstate (NU)
 Pennsylvania, east/New Jersey/New York,
 downstate (PJ)
 Pennsylvania, west (WP)
 Virginia/Maryland/Delaware/D.C. (MV)
 West Virginia (WV)
 North Carolina, South Carolina (CA)
 Georgia/Florida, north (GF)
 Florida, south (SF)
 Ohio, north (ON)
 Ohio, central (OM)
 Ohio, south (OS)
 Illinois (IL)
 Indiana (IN)
 Michigan (MI)
 Wisconsin (WI)
 Kentucky, east (EK)
 Kentucky, west (WK)
 Tennessee, east (ET)
 Tennessee, west (WT)
 Alabama, Mississippi (AM)
 North Dakota/South Dakota/Minnesota (DM)
 Iowa (IA)
 Missouri (MO)
 Kansas/Nebraska (KN)
 Arkansas/Oklahoma/Louisiana (AO)
 Texas (TX)
 Montana/Wyoming/Idaho (MW)
 Colorado (CO)
 Utah/Nevada (UN)
 Arizona/New Mexico (AN)
 Washington/Oregon (WO)
 California, north (CN)
 California, south (CS)

C.3 Utility Sector Representation

The structure of the utility related constraints in the ICF model is very similar to that of the PIES model; thus, we will concentrate here on the features of the ICF model rather than its mathematics. The model recognizes six different types of coal plants (three ranks of coal with or without scrubber), nuclear plants, oil/ gas combined-cycle, and oil/gas turbines. Existing capacity can be augmented by new capacity additions subject to build limits and capital costs; scrubbers can also be retrofitted to existing plants at a capital cost. Annualized capital costs, fuel prices, heat rates, and operating and maintenance costs are provided by the user for each plant type with the exception of coal plants where the fuel costs are provided by the coal supply sector of the model.

Environmental constraints for each region determine which type of coal each plant type in the region can burn. Specific existing coal plants are allowed to operate at variance with existing emission regulations in the near term to avoid infeasible solutions (or forced oil consumption) because of insufficient low-sulfur coal supplies or shortages of scrubbers.

The overall kwh demand for electricity by region is broken up into four load categories (base, intermediate, daily peak, and seasonal peak) to insure sufficient capacity at all times and the proper mix of plant types. Baseload transmission among selected demand regions is also permitted.

C.4. Inputs to Utility Sector

The user must provide estimates of the demand for electricity in each region and the allocation of this demand to load categories. The user must also specify the following parameters for each plant type at capacity factors of 0.7, 0.4, and 0.1:

- capital cost (\$/kw)
- heat rate (btu/kwh)
- O & M costs (mills/kwh)
- fuel costs (mills/kwh) with the exception of coal.

Coal prices are provided by the coal supply sector of the NCM. Finally, the following inputs need to be provided for each region:

- capacity expansion limits
- retrofitted scrubber costs
- transmission costs and capacities
- emission standards
- pumped storage capacity

C.5 Comment

Although the NCM is limited in scope in comparison to other energy system models, its detail in coal supply and coal-fired electricity generation is impressive. This detail, in both its data base and its modeling of coal flow by type (heat content and sulfur content), make it extremely useful in analyzing questions involving coal production, transportation, and emission controls. The model's logical structure, excellent documentation, and use of a well-known methodology should facilitate its implementation.

Appendix D

The Baughman-Joskow Regionalized Electricity Model

D.1 General

The Regionalized Electricity Model (REM) is a computer simulation model of the electric utility industry in the continental United States, geographically aggregated by nine census regions. It consists of demand, supply and financial submodels. The demand submodel econometrically determines regional electric energy demand based on demographic and climatological data for each of the states. The supply submodel consists of various equations to describe such factors as fuel requirements and costs, nuclear fuel cycle options, generation costs, transmission and distribution requirements and costs, etc. The financial submodel then computes an average regional cost of electricity, with breakdowns for two customer classes, residential/commercial and industrial, as well as an aggregate cost of electricity for the U.S. in each year. It also specifies methods of financing expansion subject to U.S. regulatory policy.

The model has been used to analyze a number of policy issues and their impacts on the utility industry. Its structure and capabilities make it a potentially useful instrument for such industry groups as EEI and NERC to perform consistent analysis for presentation to regulatory groups and the U.S. Department of Energy. Of major interest would be the effects of changes in such factors and issues as fuel pricing, nuclear policy, environmental constraints, tax policy and other regulatory policies.

D.2 Methodology

REM simulates in a deterministic fashion the behavior of the electricity sector in half-year increments covering the period from 1947 to 2010. The simulation progresses forward in time, period-by-period, with no feedback from future periods to previous periods. Decision makers make plans on the basis of projection using extrapolations of past trends. Figure D.1 displays the manner in which REM simulates the system in each time period. The components of Figure D.1 are discussed in the following section.

Source: Ref. [12].

Figure D.1

REGIONALIZED ELECTRICITY MODEL
SCHEMATIC OF MODEL LINKAGES, EXOGENOUS
DATA NEEDS, AND CENTRAL COMPUTATIONAL COMPONENTS

D.3 Utility Sector Representation

The Regionalized Electricity Model is a dynamic model of the electricity market. As such, it is composed of quantitative descriptions of both the supply and demand side of the market which interact through the price of electricity. Common to both the supply and demand sides of the market are sets of decision rules that govern the dynamic change. Suppliers choose a mix and amount of production plant--generation, transmission, and distribution equipment--to supply reliably, at least cost, electricity needs of their consumers. Consumers choose among a set of energy input possibilities--coal, oil, natural gas, and electricity--to meet their functional needs and maximize their personal satisfaction within their budget constraints. In both cases decisions are made based upon a set of stimuli, expectations, and goals. The Regionalized Electricity Model represents the authors' attempt to capture the more important of these rules in a mathematical description. In some cases, the description has been derived from experiencing and viewing the industry's behavior. In other cases it has been deduced using standard statistical techniques.

The supply side of REM is what is sometimes called a process model. It explicitly sets forth a set of technical possibilities for the supply of electricity. The decision rules take as input the various descriptions of technical alternatives (expected as capital costs, conversion efficiencies, fuel costs, etc.) and combine these with the goals of the industry (reliability, minimum cost of operation, etc.) to yield an investment or operating decision outcome. The rest of the mathematical structure of the supply submodel is memory of past decisions made, such things as mix of technologies chosen, amount of capacity in construction, when plants in construction will be completed, and so forth, or shifting of stored values to maintain synchronization with time. It treats the supply of electricity individually for each of the nine census regions of the United States. It is structured to reflect specific industry planning and operating techniques.

The demand for electricity is represented as a two-stage decision process. First, the consumer decides on a level of energy-using services that he desires based on the price of energy, the prices of other goods and services, and household income. This decision defines the expected level of energy that will be consumed. The consumer then seeks to find a combination of fuels that will provide these sources most cheaply. This two-stage model of the demand for electricity has been estimated using standard econometric techniques.

The link between the supply and demand sides of the market for electricity is the price of electricity. The price of electricity is computed in REM according to the rate-setting practices of state public utility commissions. The price of electricity is set to yield a predetermined rate of return on the utilities' rate base. Included in the rate base are capital expenditures for

generation, transmission, and distribution equipment.

The allowed rate of return on the rate base is a weighted average of the cost of capital to the utilities. In the model capital expenditures can be financed in any of four ways (ranked according to desirability): debt, preferred stock, common stock, and the State Power Authority--a lender of last resort. The amount of financing which can be provided by each of the first three alternatives is constrained by rules of prudent money management. The mix of financing instruments determines the cost of capital to the utilities which, together with capital expenditures adjusted for depreciation and taxes, yields the regional average price for electricity. From this, two prices for electricity are computed in each region: the price to the industrial sector and the price to the residential and commercial sector. The ratio of the two prices depends on the difference of the costs in supplying the two sectors, a difference resulting from expenditures on transmission and distribution equipment.

Auxiliary to these three central computational features in REM (supply, demand, and financial/regulatory calculations) are more or less detailed representations of fuel supply. National average fossil fuel prices are inserted as input to the model, then transportation markups are added to translate national fuel price scenarios into regional/state detail as needed. The nuclear fuel cycle is modeled in greater detail. It consists of detailed mass balances and a set of cost accounting relationships for each reactor type which accounts for some twelve nuclear fuel processing steps.

Exogenous to the model operation are several technical, economic, regulatory, and climatological parameters. They are set to reflect best expectations or effects of changes in policy or regulation that might impact the above parameters.

D.4 Inputs and Outputs

The factors appearing outside the dashed box in Figure D.1 comprise the inputs to the model. The output of the model is the projected regional capacity and generation pattern by technology for each period of the simulation.

D.5 Comment

The novelty of REM stems not so much from the way in which any of the individual portions of it are structured, but rather from the scope and breadth of consistency maintainable from the integration of submodels of distinct but inter-related elements of the industry. With this inter-connection a very robust and consistent analytical device is obtained.

The simulation approach frees the models representation of reality from many of the restrictions inherent in other methodologies. For

example, equations need not be linear, a separate optimization package is unnecessary, and computational considerations are not as important. This characteristic of the model enhances its flexibility and its ability to model the power system in a context that utility planners are familiar with.

The assistance of Keith Brown in preparing this appendix is recognized and appreciated by the authors.

Appendix E

The Bechtel RESPONS

E.1 General

The Bechtel RESPONS model is a regionalized static linear-programming representation of the U.S. energy system focusing on the coal sector. Figure E.1 illustrates the material/energy flow that is modeled in RESPONS. Regional supply prices and demand quantities are exogenously provided for the year of interest. Coal is classified into one of fifteen categories according to Btu and sulfur content. Coal can be transported by railroad (mixed freight or unit train), barge, or coal-slurry pipeline to households, industry, or electric utilities.

A major emphasis in the design of the RESPONS model is the coordination between the data-base and the linear program. The data-base for RESPONS was used to test and demonstrate the model's usefulness and not to be used in a policy analysis. The number and location of supply and demand regions is to be decided by the user (demonstration runs were made with five and sixteen regions). RESPONS was developed by Bechtel Corporation for its report entitled "Clean Coal Energy: Source-to-Use Economics Project."

E.2 Methodology

RESPONS employs a straight-forward linear-programming representation of the flows of energy and materials in the energy system. Supply and

demand curves are not modeled by the LP; point estimates are provided for demand quantities, supply prices and supply limits. The LP minimizes the cost of meeting the demands given known coal, natural, oil, hydro, electric, and nuclear prices.

E.3 Utility Sector

The overall Kwh demand for electricity for each region in the year of interest is met by either existing/planned capacity or by capacity that the model determines must be built in the intervening years. For existing or planned plants, only operating, maintenance, and fuel (except for coal-plants) costs appear in the objective function; for plants that are not existing or planned, annualized capital costs also appear in the objective equation. Since the model endogenously represents coal transportation the fuel costs for coal are not accounted for in the electricity sector proper. Base-loaded plants are assumed to operate at a capacity factor of .55; oil or gas plants operating in peaking modes have a capacity factor of .20. From the available documentation, it appears that the regional electrical energy demand is not broken into power demand components; thus the model only requires that yearly overall energy demand is met by the energy output of the plants operating at their capacity factor.

The types of plants represented in RESPONS are conventional coal-fired (with or without flue-gas desulfurization systems), advanced system coal-fired (combined-cycle, MHD, low Btu/gas fired), oil-fired, gas-fired, nuclear, and a single category including hydro-electric and other types. Since the model distinguishes between coal

Figure E.1

Source: Reference [18].

ENERGY DELIVERY SYSTEM SCHEMATIC

sulfur content, emissions constraints on plants can be specifically modeled by region.

E.4 Inputs and Outputs

Data inputs to the electricity sector of the model include electric power demand, electric energy imports, water requirements, and the transmission network with costs and efficiencies. In addition, the following parameters must be specified for each conversion technology: capital, operating, maintenance, and noncoal fuel costs; conversion efficiencies, plant factors, environmental effects, and existing and projected capacities.

Outputs include predicted new capacity built by year of interest, generation by plant type and region, and fuel requirements.

E.5 Comment

The usefulness of the RESPON model in regional power system studies is probably limited to studies involving coal production, transportation, and conversion by utilities. The fact that the model differentiates among sulfur content in coals enhances its usefulness in testing the effects of emission requirements. It is troublesome that electric energy demand is not broken into load categories; i.e., there is no approximation to the load curve. This will lead the model to overestimate requirements for base-load capacity and underestimate requirements for peaking, perhaps to the extent that the system predicted by the model could not meet peak demand. Since the ICF National Coal Model recognizes that electricity demand is not constant, has as much detail in sulfur and Btu content differentiation, uses the same methodology, and possesses an accepted data base; it is recommended over RESPON.

Appendix F

The Battelle Model

F.1 General

The Battelle model is a regionalized dynamic linear-programming representation of the U.S. power system with a strong focus on nuclear plant types and the nuclear fuel cycle. The model uses the NERC regions shown in Figure F.1. Coal and uranium supply functions are provided for each region; demand for electricity and the total installed capacity each year are exogenously specified. The model finds the configuration of plant types to be built over a fifty-year period that minimizes the present worth of the power system cost.

The Battelle model was developed by Battelle Pacific Northwest Laboratories as part of its "Regional Analysis of the U.S. Electric Power Industry."

F.2 Methodology

The model centers around an LP representation of the utility sector and nuclear fuel cycle.

Coal and uranium supply curves are approximated by step functions. Several preprocessors calculate capital costs, power requirements, coal prices, and fuel costs and requirements as shown in Figure F.2.

F.3 Utility Sector

The model determines how many plants of each type to build in each year in each region. A plant is assumed to have one of the two load-factor profiles shown in Figure F.3. Demand that cannot be met in a given year by previously-built plants is split by a prespecified ratio into light-load and heavy-load categories. Plants are built to meet the load in each category according to equation F.1.

$$N_{ijk} + \sum_{l \in F_{ijk}} c_l f_l = T_{ijk} \quad (F.1)$$

where

N_{ijk} = total capacity of nuclear plants with load history i installed in region k during time period j

Source: NERC

Figure F.1

NATIONAL ELECTRIC RELIABILITY COUNCIL

Source: Reference [16]

Figure F.2

INFORMATION FLOW

F_{ijk} = the set of nonnuclear plant options with load history i available in region k during time period j

c_l = capacity of a power plant of type l

T_{ijk} = total capacity of new plants with load history i installed in region k during time period j (Since the demand and total installed capacity is exogenously specified for each year, this is an input parameter).

The nuclear capacity built in a given year is constrained by equation F.2

$$\sum_{k=1}^k N_{ijk} = \sum_{r_l \in R_{ij}} c_l r_l \quad (F.2)$$

where

R_{ij} = the set of all nuclear plants with load history i that may be installed in time period j

Similar constraints model technology introduction and phase-out, present commitment, and market share situations. A number of variables and constraints are also used to model the nuclear fuel cycle. These equations will not be specified here; Figure F.4 conveys the type of detail con-

tained in the model. The objective function includes the costs involved in the nuclear fuel cycle as well as the capital and nonnuclear fuel costs.

The types of nuclear technologies represented and their availability dates are listed in Table F.1. The nonnuclear technologies, which are assumed available for all periods, are coal, oil, gas, and hydro-electric.

F.4 Inputs and Outputs

The following inputs must be provided to the model:

- energy demand by region
- capital, fuel, and processing costs
- electric generating plant fuel requirements

In addition, a number of problem definition parameters are required to describe the time span, form of the objective function, plant options by region and time of availability, and special constraints.

The output of the model is the optimal installed capacity for each plant type in each region and time period.

Figure F.3

Source: Re. [16].

PLANT LOAD FACTOR HISTORIES

F.5 Comment

The Battelle model is unique because it is a linear program that is both regionally disaggregated and dynamic in time. This feature comes at the price of less detail in the representation of the transportation of nonnuclear fuels, and a less than rigorous treatment of load factors. However, the nuclear fuel cycle detail will contribute to the model's usefulness in analyses involving nuclear options.

APPENDICES
OF
The Montana Energy and
MHD Research Development Institute

APPENDICES

Forward to Appendices

Appendices A-H describe the following models.

- A. Baughman-Joskow Regional Energy Model
- B. Brookhaven National Laboratory Model
- C. Dartmouth Systems Dynamics Group Model
- D. Jones Electric Utility Model
- E. Oregon State Simulation Model
- F. Project Independence Evaluation System
- G. Stanford Research Institute Energy Model
- H. Wisconsin Energy Model

The same format, shown in Table I, is used in the description for all of the models to aid in direct comparison of the models. This approach results in some repetition in the descriptions for some of the models and topics which are not totally appropriate for others. It is hoped that these shortcomings will be excused for the sake of consistency.

The following descriptions are based on the references presented previously in the bibliography. The references used for each model are indicated at the beginning of the appendix. Additional referencing is not used unless a very specific reference is made.

TABLE I

Format For Appendices

OVERVIEW

Model Functions
Components
Geographic Aspects

MODELING METHODS

Specific Techniques
Mathematical Formulation
Important Assumptions

INFORMATION FLOWS

Inputs
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ELECTRIC UTILITY ASPECTS

Modeling Approach
Model Details

USES FOR REGIONAL UTILITY PLANNING

Problem Class
Regional Class
Time Frame

APPENDIX A

BAUGHMAN-JOSKOW REGIONAL ELECTRICITY MODEL [4,5,6]

OVERVIEW

Model Functions

The Regional Electricity Model (REM) developed by Baughman and Joskow is a regionalized engineering-econometric-financial simulation of the electric utility industry of the United States. It includes simulation of both electricity supply and demand. The model performs six related functions which are calculations of:

1. firm expectations of the major decision variables, nationally and regionally;
2. the system expansion plans and new plant construction to meet expected load;
3. the generation of electricity via useage of available plant to meet actual load;
4. transmission and distribution requirements and costs;
5. the "cost of service" and utility cash flows; and
6. "actual" electricity demands for the alternative customer classes consistent with the endogenous set of electricity prices.

A flow diagram of how the model proceeds through these calculations is show in Figure A1.

Components

REM consists of three components: a supply model, a demand model, and a regulatory-financial model. The supply model simulates the decision-making processes involved in operating and expanding the electricity supply system, simulating the short-run and long-run behavior of the industry using "rules" of thumb" which generally reflect cost-minimizing actions. The demand model simultaneously estimates the demands for electricity, natural gas, coal, and oil for the residential, commercial, and industrial sectors. The financial-regulatory model determines the prices for electricity. The prices are based on production costs and regulatory policies. These components also simulate capital formation for new facilities.

Geographic Aspects

The supply model carries out its calculations for each of the nine United States census regions: 1) New England, 2) Middle Atlantic, 3) East North Central, 4) West North Central, 5) South Atlantic, 6) East South Central, 7) West South Central, 8) Mountain, and 9) Pacific. The demand simulation also coincides with these regions.

MODELING METHODS

Specific Techniques

Each of the three submodels employs considerably different techniques. The overall model can be considered a systems simulation model. Each of the submodels requires input from the other submodels and supplies information to these models as it moves through time.

The supply model is based largely upon engineering-economic calculations. Generation expansion calculations are made by determining the best mix to fill the load duration curve in each region. Transmission and distribution requirements are based on functions derived from time-series cross-sectional data relating requirements to load characteristics.

The demand model uses econometric techniques to determine demands for electricity, oil, natural gas, and coal simultaneously in each of the three economic sectors. Price elasticities are estimated from 1968 to 1972 regional cross-section data. The equations separate the location effects of regional price variations on industrial demand.

The regulatory financial model uses a "fair rate of return" basis to calculate the allowed prices for electricity and thus simulates rate regulation. These prices reflect this return on the capital base and the revenue requirements of the industry. The model also simulates the requirements for financing new facilities and fills these needs with various forms of debts and stock. This financing is limited according to standard financial guidelines. An additional source of funding called State Power Authority is provided to reflect potential funding shortages.

Mathematical Formulation

The mathematical formulation of the REM reflects the technique used. The econometric equations are "log-linear" elasticity relationships with variable elasticity relating demands to population and income. The mathematical formulation in the other parts of the model are quite diverse, reflecting a wide range of economic and financial calculations. The descriptions of the model in other parts of this review should give an indication of the formulation.

Important Assumptions

The major assumptions in the REM are imbedded in the model itself. That is, it is assumed that the model formulation accurately portrays the behavior of the electric utility system. The model generally is based on industry rules of thumb which reflect industry policies but in a simplified form.

INFORMATION FLOWS

Inputs

The model does not require a large number of inputs to be run; the demand model is the driver for the entire model. It requires income and population information as a basis for determining energy demands. The other major set of inputs is the cost information for the fuels and equipment used by electric utilities. A significant part of the modeling effort apparently has been directed at determining reasonable values for these inputs.

Outputs

The outputs of the model deal with the levels of demand for electricity, the various types and amounts of generation capacity built in each region, the cost of electricity, and the ability of the industry to finance needed capital investment.

ELECTRIC UTILITY ASPECTS

Modeling Approach

REM is entirely an electric utility model. It simulates the entire electric utility sphere of operation--supply, demand, and regulatory. The demand submodel also considers demands for other fuel forms. As used with REM, however, this is largely a side-effect of determining electricity demand.

Model Details

Since REM only addresses the electric utility part of the energy system, it considers the electric utility industry in considerably more detail than most of the other models reviewed. The supply model is the most detailed part of the REM.

It uses load duration analysis in each of nine regions of the United States to simulate capacity planning and construction. Eight different types of generation plants are considered in this analysis:

1. Gas turbines and internal combustion units;
2. Coal-fired thermal units;
3. Natural gas-fired thermal units;
4. Oil-fired thermal units;
5. Light water uranium reactors;
6. High temperature gas reactors;
7. Plutonium recycle reactors; and
8. Liquid metal fast breeder reactors

Hydroelectric facilities are treated as an input. Three different planning horizons are used in the model:

1. ten-year lead time for construction of nuclear plants;
2. five-year lead time for construction of thermal plants; and
3. two and one-half years lead time for gas turbines and internal combustion units.

The transmission and distribution requirements are divided into six different components for costing:

1. Structure miles of transmission capability;
2. Pole miles of primary distribution capability;
3. KVA substation capacity at the transmission level;
4. KVA substation capacity at the distribution level;
5. The KVA capacity of line transformers; and
6. The number of meters.

The demand submodel is somewhat less detailed. It determines the demand for electricity, oil, natural gas, and coal in each of the nine regions. These demands are determined for the residential, commercial, and industrial sectors. The demand calculations are sensitive to the prices for each of the energy forms.

The financial-regulatory submodel is fairly detailed, especially in its treatment of tax-related variables. Its purpose is to determine electricity prices and the financing of capital investment. In doing this, it considers four sources of financing:

1. Long-term debt;
2. Preferred stock;
3. Common stock; and
4. State Power Authority.

The fourth category is actually a hypothetical source which indicates inability of the industry to raise adequate capital when it is used. The rate base calculations include the utility's plant and equipment plus an allowance for working capital.

USES FOR REGIONAL UTILITY PLANNING

Problem Class

REM apparently was developed mainly for United States electric utility policy analysis. The high level of detail in the model should make it useful for fairly specific questions. The detail also should provide a degree of confidence that may be higher than for some of the more general models. One specific application for which the model has been used is to assess the future of the nuclear power industry and how specific government policies affect its future.

The regional disaggregation should make it equally suitable for analyzing any one of the regions. The supply and financial-regulatory calculations for each region are independent.

Regional Class

REM is a United States model built up from nine-region level. These regions represent the nine United States census districts. The model should be suited for analysis in any one of the regions or any combination of the regions.

Time Frame

In the application to the nuclear power industry mentioned previously, the time frame was through the year 1995. The model, however, should be useful for somewhat longer time frames, possibly to about the year 2000 or 2010.

Figure A1:--Flow diagram of Baugham-Joskow Model

APPENDIX B

BROOKHAVEN NATIONAL LABORATORY ENERGY MODEL [7,8,9]

OVERVIEW

Model Functions

The Brookhaven National Laboratory (BNL) energy model provides a methodology for detailed analysis of energy resource allocation and energy technologies in large-scale systems. The analysis may be conducted under constraints on energy resource availability and technologies. The BNL energy model performs an optimization to determine the "best" structure of the energy system to meet end-use demand with the available resources. The optimization normally is based on energy cost; however, a variety of objective functions can be employed. Special constraints, including environmental restrictions, may be incorporated in the model.

Components

The BNL model consists of three main components: 1) a Reference Energy System (RES), 2) the Brookhaven Energy System Optimization Model (BESOM), and 3) the Energy Model Data Base (EMDB). The BNL model also has been coupled with a fourth component, a special version of the energy input-output (I/O) model constructed at the University of Illinois, Center for Advanced Computation. This I/O model allows the energy model to be incorporated into the operation of all industry. However, only the first three components will be discussed in this review.

The heart of the BNL model is the energy network or RES. A simplified version of this is shown in Figure B1. The RES describes the detailed structure of the energy system. Each link represents a different process in taking an energy resource from extraction to end use. Each link has efficiency, cost, and environmental data associated with it.

BESOM is a routine that will calculate an optimum configuration or set of flows through the energy network described by RES. This optimum reflects resource constraints, inter-fuel substitutions, and the effect of utilizing devices.

The data base, EMDB, provides the parameters relating to each link in RES. About 600 individual processes and 200 uses are included in this data base.

Geographic Aspects

The BNL model can be applied to essentially any region desired. It has been set up for the United States, the northeastern United States, and several regions within the Northeast. The main limit on applying it to a given region is the large amount of data required to set it up. Also, the inability to represent differences in inter-regional transportation requirements for energy resources decrease the accuracy of the model for larger regions.

MODELING METHODS

Specific Techniques

The BNL model incorporates a network representation of the energy supply system in RES. BESOM, which calculates the optimum configuration, is a linear programming routine. Non-linear relationships are handled through stepwise optimization. As mentioned previously, a special input/output model has been incorporated with the BNL model for certain studies.

Mathematical Formulation

Each link in RES has parameters relating cost, efficiency, and environmental impact to the energy flow through the link. The model is designed so that additional detail can be added at any point in the system if desired for a given study. Generally, the mathematical formulation of the model takes on the following form.

The function

$$\sum_{j=1}^P C_j X_j$$

is minimized where "j" is a given path, "X" is an intermediate energy form, "C" is a cost, and "P" is the total number of paths. This minimization is subject to the following constraints:

$$\sum_{j=1}^P \frac{1}{e_{uj}} X_j \leq S_u \quad u = 1, n$$

where "e" is the conversion efficiency, "S" is the resource, and "u" represents different resources:

$$\sum_{j=1}^P d_{vj} X_j = D_v \quad v = 1, m$$

where "d" is the utilization efficiency, "D" is the demand, and "v" represents different demands; and

$$\sum_{j=1}^P f_{wj} X_j \leq B_w \quad w = 1, \ell$$

where "f" is apparently the emissions for the process, "B" is the total pollutant allowed, and "w" represents different pollutants. In the actual formulation, only feasible paths are allowed.

The model formulation includes five types of constraint equations: supply, capacity, demand, peaking and balance, and environmental. The supply equations limit the amount of a given resource which may be used in the planning year, either in total use or for a specific purpose. Capacity equations limit the generating capacity of various plant types. Demand equations describe the efficiency with which intermediate energy forms meet demands. Peaking and balance equations are used in the electrical sector. These equations allow the incorporation of load duration considerations. The environmental constraints limit emissions of various types.

Important Assumptions

The key assumption of the BNL model is that the real energy supply system can be represented adequately by an optimum calculation. However, the technique provides an important analysis tool even if this assumption is not true. Beyond this, the formulation of the model is so detailed that little can be said about the assumptions. The calculation of each parameter normally represents a number of assumptions.

INFORMATION FLOWS

Inputs

Probably the largest drawback to the BNL model is the large amount of input data required. The characteristics of each of the processes and end uses in RES must be described. EMDB is a

computerized data base on the BNL computer which describes approximately 600 processes and 200 end uses. In addition, the demand for each end use, the amount of each resource, and all of the other constraint relationships must be specified.

Outputs

The output from the BNL model is equally as detailed as the inputs. Overall measures of a system are provided in terms of energy cost, system energy efficiency, and pollutant emissions. It also can provide this information and the energy flows at each location in the network.

ELECTRIC UTILITY ASPECTS

Modeling Approach

The electric utility aspects of the BNL model are cast in the RES network representation. The particular characteristics of the electric utility system take form in the peaking and balance constraint equations mentioned previously.

Electricity demands are characterized by their contribution to base, intermediate, and peaking power. The total contribution from each of the end uses then determines the overall nature of the electric utility load. This information, in turn, is used to determine the need for and utilization of generation capacity. The BNL model also explicitly includes the possibility for utilization of waste heat from electric generation plants.

Model Details

The simulation of the electric utility is based on characterization of the load according to base, intermediate, and peak. Table B-1 shows the demand categories used in the model.

A number of different types of generation capacity are potentially available for use in the model:

1. Coal-fired steam-electric
2. Coal-fired steam-electric, combined cycle
3. Oil-fired steam-electric
4. Oil-fired steam-electric, combined cycle
5. Oil-fired gas turbine
6. Gas-fired steam-electric
7. Total energy systems
8. Light water reactor
9. Liquid-metal fast-breeder reactor
10. High-temperature gas-cooled reactor
11. Hydroelectric
12. Geothermal
13. Solar, decentralized electric
14. Pumped storage
15. Fuel cell, fossil fuel
16. Fuel cell, hydrogen
17. Methanol-fired electric

USES FOR REGIONAL ELECTRIC UTILITY PLANNING

Problem Class

The BNL model can be used to assess the benefits of individual technologies. This can be done by removing or adding a specific technology to the system and calculating the overall impact on efficiency, cost, and emissions. This allows a cost/benefit analysis for a technology to be conducted. Some 30 options have been assessed in this manner. This same approach has been used to assess groups of technologies. The resulting information can be used in developing research priorities, government policies, and the desirability of new technologies.

The model also can be used as a generalized planning tool or for specific regional questions. The later case, for example, could consider developments in an air-shed to show how best to minimize energy related emissions.

Regional Class

The BNL model has been used to describe the United States energy system and specific regions within the United States. The major limitation on region size appears to be the differences in energy transportation costs between regions. However, the model was able to represent the 1969 United States energy supply systems fairly accurately. Discrepancies that did result were attributed to this transportation problem.

Time Frame

The BNL model is a static model. It presents "snapshots" of the energy supply system. It has been used to consider possible systems as far in the future as the year 2000. Because of its static nature, the lower time frame is limited to a resolution of about five years. Dynamic considerations are likely to predominate in shorter time periods.

TABLE B-1

Electric Demand Categories Used in BNL Energy Model

<u>Demand Category</u>	<u>Load Character</u>	<u>Primary Load Factor</u>	<u>F*</u>	<u>G**</u>
1. Base-load Electric	Base Load	1.00	0.048	0.05
2. Intermediate Electric	Weekly Peak	0.05	0.091	0.10
3. Peak Electric	Weekly Peak	0.10	--	--
4. Electric Storage	Weekly Off-Peak	--	--	--
5. Spare	--	--	--	--
6. Spare	--	--	--	--
7. Spare	--	--	--	--
8. Misc. Thermal-Low Temp.	Weekly Peak	0.75	0.048	0.05
9. Misc. Thermal-Intmd. Temp.	Weekly Peak	0.75	0.048	0.05
10. Misc. Thermal-High Temp.	Weekly Peak	0.75	0.048	0.05
11. Ore Reduction	Base Load	1.00	0.048	0.05
12. Petrochemicals	Base Load	1.00	0.048	0.05
13. Spare	--	--	--	--
14. Space Heat	Seasonal Peak	0.42 ⁺	--	--
15. Spare	--	--	--	--
16. Air Conditioning	Seasonal Off-Peak	0.33 ⁺⁺	0.170	0.20
17. Water Heating	Weekly Off-Peak	--	--	--
18. Spare	--	--	--	--
19. Air Transport	--	--	--	--
20. Truck, Bus	--	--	--	--
21. Rail	Weekly Peak	0.50	0.091	0.10
22. Automobile	Weekly Off-Peak	--	--	--

* Fraction of energy reassigned to peak electric demand.

** $F = G/(1+G)$ or $G = F/(1-F)$

+ The space heating season is assumed to be five months long, so $LF = 5/12$

++ The air conditioning season is assumed to be four months long, so $LF = 4/12$

Figure B1.--Simplified Diagram of Energy System Network Used in BLN Energy Model.

APPENDIX C

DARTMOUTH SYSTEMS DYNAMICS GROUP MODELS [10,11]

OVERVIEW

A number of energy models have been developed by the Dartmouth Systems Dynamics Group (DSDG). The following review considers only the COAL1 model developed by Nail [10]. The COAL1 model was selected for this review because it is a complete energy supply/demand model, whereas other DSDG models consider only specific energy sectors. The COAL1 model incorporates many of the other models into its structure. The electric utility model developed by Ford may also be of interest for utility planning [11]. However, only the parts of the Ford model incorporated into the COAL1 model are addressed here.

Model Functions

The function of the COAL1 model is to show the ability of the United States energy system to respond to changing conditions during the "transition period." It is designed so that various United States energy policies affecting both supply and demand can be tested for their positive and negative effects on balancing energy supply and demand, minimizing oil and gas imports, minimizing energy price increases, and minimizing environmental impacts.

Components

The COAL1 model was built from four components: energy demand, oil and gas, electricity, and coal. Figure C1 shows the information flows between these components and the basic causal structure of each component. Each of the sectors is described briefly in the following paragraphs.

The demand component determines the behavior of net or end-use energy demand through time. It relates total energy demand to the GNP and the average cost of energy. Three forms of end-use energy are considered: oil and gas, electricity, and coal. The demand component simulates shifts over a period of time in the relative demand for each of the three forms in response to relative changes in energy prices.

The oil and gas component attempts to satisfy demands for oil and gas from end users and electric utilities. The ability to produce oil and gas depends upon the capital investment and resource depletion. The oil and gas component includes a financial sector which generates new capital investments and two production subsectors that allocate investments to conventional or synthetic fuel facilities.

The electricity component simulates the financing and fuel-mix decisions made by electric utilities. Utility regulation is modeled explicitly in this component. Utilities are allowed to choose among nuclear fuel, coal, and oil and gas as energy sources for future steam-electric generation capacity. Capital costs, fuel costs, and environmental limitations are used to determine the fuel mix.

The coal component of the COAL1 model attempts to satisfy demands for coal from end users, electric utilities, and synthetic fuels. Coal production from underground and surface mines is simulated separately. Surface production capability depends upon the capital investment and resource depletion, whereas underground production also depends upon the trained labor available.

Geographic Aspects

The COAL1 model is strictly a United States energy model. No regional definition within the United States is included in the model. The model, however, does consider oil and gas imports from outside of the United States.

MODELING METHODS

Specific Techniques

The COAL1 model is a classic dynamic systems simulation (DSS) model, if it is proper to call a modeling technique as new as DSS classic. Emphasis is placed on defining the causal structure in the system and the delays inherent in responding to change.

Mathematical Formulation

The COAL1 model is formulated in DYNAMO throughout. The formulation of the equations however, does vary with each component. The demand equations utilize a price elasticity formulation with a variable elasticity. Shifts among the forms of energy are based upon non-linear functions of price ratios. Gas and oil, coal, and electricity production capabilities are formulated as non-linear functions of capacity relative to demand. That is, some demand is unmet before the maximum theoretical utilization is achieved. The coal, electricity, and oil and gas components must allocate investments among more than one form of production--different types of capacity with electricity, surface versus underground with coal, and conventional versus synthetic with oil and gas. The allocation is done with non-linear functions of cost ratios. The output capacity for coal is determined with a modified Cobb-Douglas production function utilizing variable coefficients. The production factors for surface-mined coal are resource and capital. Labor is added for underground mining. Output capacity for electricity and oil and gas is based on the capital investment. With oil and gas a multiplier also decreases the capital effectiveness as the resource is depleted.

Important Assumptions

As with all DSS models, every structural relationship is potentially an important assumption. It would be necessary to go through the model formulation step by step to address each of these. Such a discussion cannot be made here but is done by Nail [10] who summarizes the important assumptions (see Table C-I). The author feels that there are several other important assumptions built into the model that potential users should be aware of. The COAL1 model assumes oil and gas can be lumped together as a single resource, selection among fuels and investment alternatives is based on price or cost ratios rather than absolute differences, and the switching away from coal and to electricity during periods of constant prices has been due to the convenience of the fuel.

INFORMATION FLOWS

Inputs

The COAL1 model is self-contained; that is it can be run without any inputs being supplied by the user. On the otherhand, the DYNAMO formulation makes it fairly easy for any relationship in the model to be altered by someone who is familiar with the model and DSS techniques. The main inputs to the model are changes in model parameters or relationships which reflect various policies. The major input task of the user is then to determine how to modify the model properly to reflect a given policy.

Outputs

The DYNAMO formulation allows essentially any variable in the COAL1 model to be treated as an output if desired. The main outputs are summarized in Table C-II.

ELECTRIC UTILITY ASPECTS

Modeling Approach

Electric utilities are treated as a distinct component of the COAL1 model. This component addresses major issues pertaining to future development:

1. Financing new utility investments; and
2. Choosing the mix of new electrical generating capacity.

Nail presents the following central concepts or assumptions for the electric utility component.

1. Total utilities' investment is financed from internal funds (revenues) and external sources (debt, equity). Yearly investment is limited by an upper bound to the external/internal financing ratio.
2. New investments are dependent on generating capacity needs (measured by the capacity utilization factor) and rate of return of the industry.
3. Because of its limited potential for expansion, hydropower generation of electricity is assumed to be exogenous; saturating at 50 percent above present level.
4. The fraction of total investment allocated to construction of nuclear power plants is dependent on a comparison of nuclear and fossil costs (including both capital and fuel costs).
5. The fraction of new fossil plants with coal-fired boilers is dependent on a comparison of the cost of coal vs. oil and gas and consideration of whether current SO₂ emissions violate emission standards. [10]

Model Details

The COAL1 model separately considers steam-electric capacity powered by coal, oil and gas, and nuclear fuel. Hydroelectric capacity is specified and is not addressed in the model logic. The overall supply and demand balance is measured by the "capacity factor". The capacity factor is calculated with a non-linear relationship between capacity utilization and the ratio of demand to capacity. As the demand-capacity ratio increases, an increase in shortages occurs as capacity is unable to meet peak demands. This function can be altered to show the effect of load-leveling actions.

Financing electric utilities is based upon the need for new capacity and transmission and distribution facilities. Financing is based upon the ability to attract sufficient funds from internal and external sources. This ability is a function of the industry rate of return. The impact of utility regulation is included in financial considerations, including the lag time required for regulatory agencies to react to financial changes.

The selection of new capacity is determined by first defining the fossil nuclear mix based upon the relative cost of the two and then allocating the fossil fraction to oil and gas and coal.

USES FOR REGIONAL ELECTRIC UTILITY PLANNING

Problem Class

The COAL1 model was designed specifically for United States energy policy analysis. The major problem addressed by the model is maintaining an energy supply/demand balance and minimizing imports during the "transition period;" the transition period being the time that is foreseen as necessary to convert to ultimate energy sources such as solar or fusion. Particular policies addressed pertaining to electric utilities include eliminating the regulatory lag, increasing the allowed rate of return, accelerating nuclear development, lowering environmental restrictions on coal use, and developing and implementing environmental emission reduction technology. These applications are indicative of the types of electric utility questions the COAL1 model may address.

Regional Class

The COAL1 model was developed for the entire United States, with no smaller regional distinction included. This national perspective limits the application of the model in regional planning questions. However, the model should be useful for considering some of the specific policy questions for larger regions which are representative of the United States as a whole.

Time Frame

The COAL1 model was designed to operate through the 1950 to 2010 time period. The 1950 to 1975 period is used to validate that the model gives a reasonable representation of historical behavior. The 1975 to 2010 period addresses what Nail terms the transition period to ultimate energy sources.

TABLE C-I

Important Assumptions In The COAL1 Model [10]

Demand Assumptions

- . Energy demand is determined by GNP and the efficiency of energy use.
- . Energy price increases provide the incentive for improvements in end-use efficiencies.
- . Oil and gas, coal, and electricity are substitutable to some degree in the final energy markets. The degree of substitution is dependent on relative price and convenience of the fuels.
- . The consumer's response to a change in energy prices is delayed, as time is required to change consumption habits and technologies.

Supply Assumptions

- . Domestic production of energy is determined by the output capacity of production facilities and their capacity utilization.
- . Production capacity is dependent on the following factors in COAL1:
 - conventional oil and gas - capital, resources
 - synthetic oil and gas - capital, R&D, coal availability
 - electricity - capital, environmental regulation, fuel availability
 - coal - capital, labor, resources, environmental and safety standards

TABLE C-I (Continued)

- . The ability of the oil and gas, coal, and electric utility industry to generate new capital investment from internal (retained earnings) and external (debt, equity) sources is limited. Price regulation (in the oil, gas, and electric utility industries) tend to reduce investments below the maximim limit.
- . There is a limited stock of recoverable oil, gas, and coal resources in the United States. As resources are depleted, the efficiency of the production capital stock decreases (the capital/output ratio increases).
- . There exists unavoidable delays that limit the responsiveness of energy supply; for example, 3 to 10 year construction delays, R&D delays (synthetic, stack gas scrubbers), underground coal labor hiring delays, and response delays in the energy financing sectors.
- . As oil and gas production capacity falls behind demand, the short fall is made up with oil imports.

TABLE C-II

Main Outputs Of COAL1 Model

Overview

Energy Consumption--Demand Ratio
 Gross Energy Demand
 Average Energy Price
 Energy Investment/GNP
 Energy Supplied by Nuclear and Hydro, Coal,
 Oil and Gas, and Imports

Energy Demand

Net (End Use) Energy Demand
 Net Demand Supplied by Coal, Oil and Gas,
 and Electricity

TABLE C-II (Continued)

Oil and Gas

Oil and Gas Consumption--Demand Ratio
 Oil and Gas Demand
 Average Oil and Gas Price
 Coventional Production
 Synthetic Production
 Imports

Electricity

Generation--Demand Ratio
 Electricity Demand
 Electricity Price
 Generation Supplied by Coal, Oil and Gas,
 Nuclear, and Hydro

Coal

Coal Production--Demand Ratio
 Coal Demand
 Coal Price
 Coal Produced Underground and in Surface
 Mines

Figure C1.--Structure of the COAL1 Model.

APPENDIX D

JONES REGIONAL ELECTRIC UTILITY MODEL [12,13]

OVERVIEW

Model Functions

The model developed by Jones is intended to be the electric utility component of a larger dynamic regional energy systems analysis (DRESA) model. As part of the DRESA model, the electric utility component model simulates the functioning of the regional electric utilities and addresses the following questions in the region:

1. The ability to meet demands for electrical energy;
2. The cost of generating electrical energy;
3. Energy resources used for generating electricity;
4. Capital requirements for generating facilities; and
5. The energy and cash flows from inter-regional transactions involving electrical energy.

The electric utility component model also is intended to be an independent model for regional electric utility studies. The function of the model in this role is essentially the same as above except that information that normally would come from other components of the DRESA model must be supplied as inputs. No other components of the DRESA model have been completed at the time this report is being prepared. Thus, the independent role must be considered the function for the model.

Components

The model can be divided into five groups of activities which it simulates:

1. Forecasting future conditions;
2. Planning the addition of new generating facilities;
3. Securing supplies of energy resources;
4. Intermediate planning of operation; and
5. "Hour-to-hour" scheduling.

Figure D-I gives a standard Forrester diagram of a simplified form of the model showing the major components of the model. This figure only represents an overview of the structure of the model; the actual structure of the model is considerably more detailed.

Geographic Aspects

The electric utility model developed by Jones is intended for a relatively small region. The only region to which it has been applied is the state of Oklahoma. The electric utility industry in that region consists of two large privately owned facilities; two small publicly owned facilities, one of which operates all of the hydroelectric facilities in the state; and a number of small municipal utilities and rural co-operatives.

Presumably, the model could be applied to other regions of similar sizes. The nature of the model is such that it treats the region much as if the electric utility industry in the region consisted of a single utility company. This approach should make simulation regions as small as a single major utility company's service area possible. The approach, however, does tend to set an upper limit on the simulation region. The region probably should not include more than three or four major utility companies. Regions approximated by a single state are about the appropriate size.

MODELING METHODS

Specific Techniques

The general modeling approach used by Jones is that of dynamic systems simulation (DSS). The model developed by Jones is different from most DSS's in the level of detail included. Most of the actual calculations in the model are based on engineering and economic analyses of how utilities conduct the planning and operation of the system. DSS provides an overall framework of the dynamic behavior of electric utility planning and operation.

Mathematical Formulation

There is no single mathematical form used in this model. As with all DSS models, key relationships are expressed in time derivative form. Since most of the calculations deal with engineering and economic calculations, each component of the model is somewhat different.

All forecasting is done with first-order delays which allow variables to grow or decline exponentially or approach a constant value exponentially. Most other calculations deal with matching capacity, energy resources, and generation to the load duration curve. Capacity planning is done by comparing fixed and variable costs and availability curves of various types of generation capacity and calculating which portion of the load duration curve each best fills. This calculation requires integrating the availability and variable cost of increments of capacity in the area under the load duration curve. Similar calculations are required in planning for energy resource (fuel) requirements, intermediate planning, and hour-to-hour operation.

Important Assumptions

A number of important assumptions are mingled with the formulation of particular algorithms. These cannot be addressed specifically without going into the details of each algorithm. Generally, the algorithms are based upon pseudo optimum calculations rather than conducting fully optimum calculations. Other important assumptions deal with the division of input information between parameters and variables. Although they may be varied, the model formulation does not specifically address the effect of changing parameters, whereas it does for variables. An error in simulation arose in at least one particular case where incorrect total electric cost resulted from rapidly increasing capital cost of generation facilities which is treated as a parameter.

A considerable amount of input information is required. It is likely that a number of assumptions will be made in formulating this information for any specific study.

INFORMATION FLOWS

Inputs

Input information required for the model is divided into four groups: inputs, parameters, initial conditions, and structure options. The information classified as inputs varies with time; these variations are addressed in the structure of the model. Information classified as parameters, on the other hand, may vary with time, but the effect of varying the values is not addressed in the model structure. Initial conditions are required for all state variables and "delayed" derivatives. Structure options mainly are concerned with the dimension of different aspects of the model.

Table D-I details the input information required. Generally, a user must supply all of this information. The model has been run for Oklahoma, so much of the information required for that region has been compiled. Much of this would need to be

updated and modified for specific studies. Data such as heat rates, availabilities, construction times, etc., will remain the same for other regions however.

Outputs

The outputs from the model are listed in Table D-II. These outputs are intended to assess the ability of the electric utility industry in the study region to meet demands and the cost of doing so. They also indicate the energy flows required to do this.

ELECTRIC UTILITY ASPECTS

Modeling Approach

The entire model developed by Jones deals with the electric utility industry. This approach results in substantially more detail on electric utilities being represented than in most of the other models reviewed. As was discussed previously, the model is designed to be a component of an overall regional energy system simulation as well as an independent model. The model has been used only in the independent mode to date.

The model is strictly for electrical supply, and the demand for electrical energy is an input to the model.

The model considers only generation and obtaining the needed energy resources. It does not address transmission and distribution, financing, or other aspects of the electric utility industry. It also does not consider other parts of the energy supply/demand system.

Model Details

Because of the detailed nature of this model, only a general discussion is presented. The degree of detail is specified in part by the user. The last section of Table D-I indicates the options the user has. The user also may eliminate all inter-regional transactions if desired. An in-depth explanation of the model is given in the documentation by Jones [12]

The model simulates forecasting of peak demand, energy resource (fuel) prices, and the availability of energy resources. The forecasts are generated by smoothing the percentage rate of change with a first-order delay. The result is an average growth or decline rate which is used to extrapolate what to expect for future conditions.

Demand for electricity is characterized by a load duration curve. The shape of the curve may be changed at any time during the simula-

tion. However, the model does not project any changes in the curve when it is making planning calculations. The availability of various types of generation facilities are characterized by an availability curve similar in nature to the load duration curve. Energy resources used in generation are classified as constant or declining. Constant resources are those where a contract is made for a certain delivery rate for a specified time period. Declining resources are those whose delivery rates decline as the resource is produced.

Long-term planning of generation is simulated by specifying an arbitrary planning year (normally ten years into the future). The fixed and variable costs, including fuel, are compared for existing and potential new generating capacity, and a least-cost mix that can fill the load duration curve is determined. Construction of capacity then is initiated which will lead to the mix. Energy resources then are obtained which correspond to this mix of capacity.

Intermediate planning considers a one-year time frame. The variable costs of available generation are compared and plans are made on how to fill the expected load duration curve in the best way. It is at this point that arrangements are made to buy or sell firm power.

The "hour-to-hour" operation simulation is treated much the same as intermediate planning except that emergency and economy energy transactions are included. The numerical time step for these calculations is normally one year. Economy energy supplies and demands are represented by curves showing the amount available or demanded at different prices and times on the load duration time axis. Emergency energy supply and demand are represented by similar, single curves.

USES FOR REGIONAL ELECTRIC UTILITY PLANNING

Problem Class

Jones cites four applications for the regional electric utility model:

1. Prediction of the response of the electric utility industry in a region to scenarios for future conditions;
2. Generalized dynamic response of regional electric utility industries to fluctuating or erratic conditions;
3. Analysis of the effect of regulations and controls by government agencies, and
4. Analysis of policies and procedures (forecasting, generation expansion, etc.) used by electric utilities.

The only application of the model to date has been to assess a hypothetical restriction on the use of natural gas as a fuel for generation. This application was made primarily to demonstrate how the model might be used.

Some hydroelectric facilities were included when the model was validated with historical data for Oklahoma. However, the general structure of the model does not lend itself to those regions utilizing large fractions of hydroelectric facilities. The model should be applied to systems relying largely on thermal-electric generation.

Regional Class

The Jones model is strictly an intra-regional model. To date, the model has been applied only to the region defined by the state of Oklahoma. It was designed, however, to be applicable to almost any region of a similar size. The nature of the model limits its use to relatively small regions. The region probably should be limited to three or four major utilities but may be as small as one major utility company.

Time Frame

There are no specific limits to the time frame for which the model may be applicable. The study for which it has been used extended through the year 2000. This should be a reasonable time frame for other potential applications.

TABLE D-I

Input Information Required for Jones Model

<u>Inputs</u>	
Peak Demand	
Market Price of Each Energy Resource	
Quantity of Each Energy Resource Available	
Fraction of Each Energy Resource Available for Generation	
Fraction of Energy Resource Available as Long-Term Supply	
Economy Energy Supply (Multiple Curves)	
Economy Energy Demand (Multiple Curves)	
Firm Power Supply (Multiple Curves)	
Firm Power Demand (Multiple Curves)	
Emergency Energy Demand (Single Curve)	
Emergency Energy Supply (Single Curve)	
Maximum of Each Capacity Allowed	
Limit on Capital Available for Generation Facilities	

TABLE D-I (Continued)

Parameters

Demand Characteristics (Single Curve)
 Availabilities for Each Type of Capacity
 (Single Curve)
 Capital Cost of Each Type of Capacity
 Yearly Fixed Cost for Each Type of Capacity
 Non-Fuel Variable Cost for Each Type of Capacity
 Heat Rate for Each Type of Capacity
 Construction Time for Each Type of Capacity
 Expected Demand Characteristics (Single Curve)
 Firm Power Demand Characteristics (Single Curve)
 Desired Reserve Capacity
 Deliverability to Resource Ratio for Declining
 Energy Resources
 Forecasting Delay for Each Variable Forecast
 Supply Delay for Each Energy Resource

Initial Conditions

On-Line Capacity of Each Type
 Semi-Retired Capacity of Each Type
 Capacity Under Construction of Each Type
 Long-Term Capacity Contracts from Each Source
 Future Long-Term Capacity Contracts from Each
 Source
 Smoothed Value for Each Variable Forecast

TABLE D-I (Continued)

Supply of Each Declining Resource
 Deliverability of Each Constant Energy Resource
 Future Deliverability of Each Constant Energy
 Resource
 Price of Each Long-Term Energy Supply
 Peak Demand, Previous Time Step (PTS)
 Price of Each Energy Resource, PTS
 Quantity of Each Energy Resource Available, PTS
 Fraction of Each Energy Resource Available for
 Generation, PTS

Structure Options

Number of Energy Resources
 Classification of Each Energy Resources as
 Declining or Constant
 Number of Generation Capacity Types
 Number of Capacity Contracts Available

TABLE D-II

Output Information

Amount of Each Type of Generation Facility Constructed

Energy Generated by Each Type of Generation Facility

Quantity of Each Energy Resource Consumed

Total Electrical Energy Supplied to Region

Unmet Demand for Electrical Energy

Total Cost of Generation

Economy Energy Purchased

Economy Energy Sold

Firm Power Purchased

Firm Power Sold

Firm Energy Purchased

Firm Energy Sold

Emergency Energy Purchased

Emergency Energy Sold

Figure D1--Simplified Forrester Diagram of Electric Utility Simulation

APPENDIX E

OREGON STATE SIMULATION MODEL [14,15,16]

OVERVIEW

Model Functions

The Oregon State Simulation Model (OSSIM) is a comprehensive model of socio-economic activity for the state of Oregon. It is designed to account for the factors influencing decisions on economic growth and environmental quality.

"The principle purpose of OSSIM was to provide a mechanism for making research results available to state-level policy makers that would:

(1) heighten their appreciation for the complexity and dynamic interrelatedness of population growth, economic activity, energy consumption, land use, and environmental quality.

(2) provide them with one or more means of estimating the likely consequences of outcomes associated with various policies and scenarios."
(11)

Components

OSSIM consists of seven components: 1) demographic, 2) economic, 3) land use, 4) energy, 5) pollution, 6) transportation and 7) government revenue. Figure E-I shows the interaction of these components.

The demographic component provides a detailed simulation of the population of each of the three regions used in OSSIM. The demographic simulation is based on the number of families rather than a standard age-cohort model. Also, the family calculations are keyed on adult females. The families are resolved into two fertility classes--female under 45 and female over 45; two social strata--marginal and mainstream; and nine sizes based on the number of minor children. The simulation traces the formation, growth, and extinction of families. It also accounts for social diffusion of families. Birth rates and migration are key variables in determining the growth and nature of the population. Both variables are modeled as class specific and dependent upon economic conditions within the region.

The economic component is a macroeconomic model for each of the three regions. This component is divided into four major sectors: 1) logging and forest products, 2) agriculture and food products, 3) manufacturing, and 4) services. The logging and forest products sector is driven by the availability of the supply of sawtimber. The agriculture and food products sector is driven by the availability of agricultural land. The manufacturing sector is driven by the endogenous and exogenous demand for durable and non-durable goods. It is disaggregated into 16 non-resource based industry groups. The services sector is driven by endogenous demands resulting from other sectors, the labor force, government services, housing construction, and investment. The output, value added, labor requirements, and investment are determined for each sector. Also, interactions between the three regions used in OSSIM are considered in each sector.

The land use component simulates the transfer of land among eight different categories: unused, open space/wilderness, forest, agriculture, low-density residential, medium-density residential, high-density residential, and commercial/industrial. Demand for residential land is determined by the number of households and their income distribution. This demand drives the conversion of agricultural land to residential land. The need for commercial/industrial land is determined by the manufacturing and service sectors of the economic component. Transfers of land to and from the forest, open space/wilderness, and unused categories are policy inputs.

The energy component considers only electrical energy. Petroleum, natural gas, and coal are not considered as there is no significant production of these resources in Oregon. Although substantial amounts of electricity are generated in Oregon, OSSIM simulates only the demand for electrical energy. The prices of electricity and competing energy resources are input scenarios.

The pollution component translates levels of economic activity into rates of discharge of air pollutants. Unfortunately, there is virtually no documentation available on this component. [16]

The transportation component allocates population growth to the five largest urban areas of each region. It then determines transportation demand within and between these urban areas. Although it is shown as an integral part of OSSIM in Figure E-I, the transportation component has not been run in conjunction with the rest of OSSIM to date. [16]

The government revenue component uses outputs from other components to determine the revenue to the State from personal income, corporate income, and motor vehicle taxes. These are based, respectively, on the number of households, their size and income distributions; value added in the economic sectors; and the level of transport activity.

Geographic Aspects

OSSIM was developed specifically for the state of Oregon. The state is divided into three regions in the model: the Willamette Valley, the Coastal Region, and Eastern Oregon. Each of these regions has an economic base and population density substantially different from the others. The components discussed previously are modeled in parallel for the three regions. The economic component also considers interactions between the regions.

MODELING METHODS

Specific Techniques

Dynamic systems simulation (DSS) is used throughout OSSIM. In several sections, other techniques not normally associated with DSS are also used. Regional allocation matrices are used to distribute product output to the three regions for the logging and forest products and the agriculture and food products sectors. Regional shift matrices and input/output techniques are also used in determining the demands for services and manufactured goods.

Mathematical Formulation

The mathematical formulation of the model is consistent with the DSS technique. The prime variables are levels which describe the state of the system and rates which describe the change in levels. The specific formulation of each component is more fully described in the Overview section of this report.

Important Assumptions

In a model as diverse as OSSIM, a number of assumptions are necessarily made in formulating the model. As with all modeling techniques, and particularly DSS, the structure of the model represents many of the assumptions. Table E-I summarizes assumptions which in the author's opinion are important to the formulation of the model for the four main components: demographic, land use, economic, and energy.

INFORMATION FLOWS

Inputs

Each component of OSSIM requires several dynamic inputs in order to run. Many of these are provided by the outputs of other components. The remainder must be supplied by the user as scenario inputs. In addition, a number of parameters and initial conditions must be specified. A basecase simulation which includes values for all inputs not internally generated is programmed. The user may selectively change these inputs. Table E-II summarizes the inputs for each of the four main components.

Outputs

The outputs from OSSIM are intended to characterize the general socio-economic status of Oregon. Also, outputs from one component may serve as an input to other components. The outputs for OSSIM are summarized in Table E-III.

ELECTRIC UTILITY ASPECTS

Modeling Approach

The entire energy component of OSSIM deals with electrical energy demand. The general approach is to calculate demand by the equation

$$D = U \cdot Y$$

where "D" is the demand, "U" is the energy use intensity, and "Y" is a measure of economic or other activity. The intensity is considered a function of price and time and is represented by

$$U(p,t) = U_0(t) \cdot F(p)$$

where the function "F" contains all of the price effects of "U₀" contains the non-price effects. Price effects are represented with own and cross price elasticities derived from historical data. The prices of oil and natural gas are included in the electricity demand calculations. First order delays are used to represent the time lags inherent in responding to price changes.

Detail Included

The demand for electricity is calculated separately for each of four traditional sectors: 1) industry, 2) residential, 3) commercial, and 4) transportation. Industrial activity is disaggregated to the two digit SIC level and calculated separately for each of these classifications. Industrial activity for use in the energy demand calculations is measured in terms of value added.

The residential sector considers only energy used for domestic purposes and is based on the number of customers. The use per customer is calculated by projecting appliance saturations

and the energy use per appliance.

Energy use in the commercial sector is not disaggregated. It is intended to act as a residual representing energy consumption not accounted for in other sectors. Commercial consumption is based on the number of employees in the services component.

Electricity use by the transportation sector historically has been a very small part of total electricity consumption, being confined to lighting and traffic control use. OSSIM relates this consumption to the miles of streets and highways.

USES FOR REGIONAL UTILITY PLANNING

Problem Class

OSSIM was designed as a socio-economic policy analysis tool for the state of Oregon. The energy component should be useful for assessing the impacts of various policies on electrical energy consumption. These policies can pertain to energy questions or other socio-economic questions. Five specific energy policy runs are documented. These are:

1. continuation of historical prices,
 2. electricity prices increase,
 3. fossil fuel prices increase,
 4. all energy prices increase, and
 5. no electricity conservation takes place.
- (11)

These runs primarily show the effect of energy prices on consumption. However, the wide range of socio-economic factors included in OSSIM should make possible a broader range of policy analysis pertaining to electrical energy demand.

Regional Class

OSSIM was developed specifically for the state of Oregon and would not be directly applicable to other regions. However, the author was personally involved in the development of a model for the state of Montana based in part on the concepts and methodologies found in OSSIM.*

Time Frame

The nominal time frame for OSSIM is 40 years running from 1970 to 2010.

* See: "Natural Gas Demand Study," Report Number 3M19:76N08, Montana Energy and MHD Research and Development Institute, December 1976.

TABLE E-I

Important Assumptions in OSSIM

<u>Component</u>	<u>Assumptions</u>
Demographic	It is not necessary to use detailed age structure with the various demographic categories.
Economic	The state's economy is supported and limited by fundamental resource bases: logging and forest--renewable supply of sawtimber agriculture and food--availability of agricultural land.
Land Use	Residential and commercial/industrial land ultimately comes from agricultural land and decreases the availability of land to agriculture.

TABLE E-I (Continued)

<u>Component</u>	<u>Assumptions</u>
Energy	Historical energy demand is in price equilibrium (for data analysis). The time response of demand to price changes is characteristic of a first order delay. The response of demand to price changes is represented with a series of price elasticities.
General	Energy prices do not affect variables in other components.

TABLE E-II

Inputs for OSSIM

<u>Component</u>	<u>Inputs</u>
Demographic	Wage Income Distribution* Unemployment* Job Training Welfare
Economic	
Manufacturing	Demand for Consumer and Capital Goods**
Logging and Forest Agriculture and Food	Timber Available Agriculture Land Avail- able*
Services	Output, Value Added, and Capital Investment of Other Economic Sectors* Consumption by Labor Force* Demand for Government Services* Housing Construction* Investment*
Land Use	Demand for Housing* Demand for Commercial/ Industrial Land* "Reclamation" of Unused Land Reforestation of Agricul- tural Land Preservation of Forest and Agricultural Land
Energy	Electricity, Gas, and Oil Prices Number and Type of Households* Number of Service Employees* Manufacturing Output* Irrigated Acres* Miles of Street and Highway*

TABLE E-III

Outputs from OSSIM

<u>Component</u>	<u>Outputs</u>
Demographic	Population Labor Force Demand for Housing Household Income Distribution
Economic	
Manufacturing	Sector Output Value Added Labor Demand Capital Investment Required
Logging and Forest	Forest Products Produced Labor Demand Capital Investment Required
Agriculture and Food	Agricultural Production Capital Stock Labor Demand Capital Investment Required
Land Use	Quantities of Land in Eight Classes: Commercial/Industrial High, Medium and Low Density Residential Agricultural Forest Wilderness Unused
Energy	Annual Electrical Energy Consumed Electrical Energy Use Intensity

*Determined internally to OSSIM.

**Determined partially within OSSIM.

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Figure E1. Structure of OSSIM.

APPENDIX F

PROJECT INDEPENDENCE EVALUATION SYSTEM [17,18,19]

OVERVIEW

Model Function

The Project Independence Evaluation System (PIES) provides comprehensive energy forecasting and analysis capability for the United States. PIES calculates the detailed supply/demand market equilibrium for major fuels by region and sector. Projections of domestic production, refining, electric generation, and energy prices in each section by region are made. Energy imports also are calculated. An economic impact component permits analysis of the impacts of energy changes on variables such as GNP, investment, personal income, and unemployment.

Components

PIES consists of eight components:

1. The PIES integrating model (PIESIM);
2. The demand model;
3. The supply models and data;
4. The utilities model and data;
5. The refineries model and data;
6. The transportation model and data;
7. The economic impact models and data;
and
8. The international models and data.

Figure F1 shows the overall structure of PIES and how the components fit together. Each component is described briefly in the following paragraphs.

The integrating model (PIESIM) is the central point of PIES. It combines the supply and demand information provided by other components through an equilibrating mechanism to produce an equilibrium forecast. It also specifies and implements special market conditions. The equilibrium forecasts produced by PIESIM include quantities and prices which are consistent with one another. This consistency is maintained from production through conversion and transportation to ultimate consumption.

The regional demand forecasting model (RDFOR) generates the demand functions used by PIESIM. RDFOR is a behavioral model consisting of econometric equations. The forecasting program of RDFOR uses these equations to produce annual forecasts of energy demand by fuel, sector,

and region. The inputs required for RDFOR include path of fuel prices by sector and region; population, income, and industrial activity; impacts of conservation programs; and dispersed solar and geothermal use.

Oil and gas supply curves for PIESIM are constructed using two different methodologies. For the well-established producing areas of the lower 48 states (on shore and offshore) and portions of south Alaska, supply curves are derived using a detailed oil and gas supply model. For more speculative sources, the supply curves are based on careful engineering analysis, judgement, and similar modeling techniques.

Coal supply curves are provided for several varieties of coal (differentiated by their Btu and sulfur content). Supply functions are constructed for each coal supply region listed in Table A6. Coal supply functions are generated by allocating the Bureau of Mines' estimates of demonstrated coal reserves to regions and coal types. Cost estimates are made by assessing the cost to open and/or operate mines of various types.

The electric utilities model optimizes the construction and operation of facilities to minimize the cost of electricity. Generation capacity is characterized by age, type, and energy source. Optimization is done on a regional basis.

The refineries model classifies each crude type by its major attributes, which determine the petroleum products it will yield upon refining and the cost of refining. A detailed off-line model is used to develop this characterization. The results of the off-line model are used to give an approximation of appropriate yields, costs of modifying yields, and refining capacity needs.

The transportation networks for oil and gas are modeled as direct links between supply, refinery, and demand regions. Separate links are provided for each fuel type and transportation mode. A more detailed transportation network for coal is modeled. Coal by rail is allowed to move between nodes on a rail network which interconnects most of the largest metropolitan areas.

A waterways network also is used which follows major water routes. Additional links are provided to connect coal supply regions to rail and waterway nodes, to connect rail and waterway nodes, and to connect rail nodes to utility and demand regions.

The economic impact models show the effect on the national economy of the status of the energy system, i.e., depressed GNP due to energy shortages and high prices. These results then can be used to determine if the macroeconomic conditions used to calculate energy demands are realistic. If not, new scenarios must be used. The impacts are shown on a national scale but can be broken down to a regional basis. However, the means for allocating impacts to individual regions does not incorporate information about the energy system in that region.

The International Energy Evaluation System (IEES) is a collection of models very similar to the domestic portion of PIES. IEES can be run in conjunction with PIESIM or can be used to project import demand as a function of world oil prices.

Geographic Aspects

PIES is designed for energy evaluation for the United States. Four different sets of regional classifications are used which correspond to demand and utility regions, oil and gas supply regions, coal supply regions, and refinery regions. These regions are identified in Table F-1.

The international component of PIES extends the model's capability for energy market analysis to include other parts of the world. This international component uses the following regions:

1. United States
2. Japan, Canada, OECD Europe, and Australia/
New Zealand
3. OPEC countries
4. Non-OPEC, less-developed countries
5. Russia, Eastern Europe, and China.

MODELING TECHNIQUES

Specific Techniques

PIES combines three distinct modeling techniques: econometrics for demand, linear programming for supply, and iterative balancing in the integrating model. The demand model generates demand functions from econometric equations derived from historical data. These equations base energy demand upon population, income, and industrial activity as well as energy prices. Own-price and cross-price elasticities are used so that demands for a given fuel depend upon all prices. The demand model is path dependent. That is, the demand in a given year depends not only on the prices in that year but in previous

years as well. Given the general nature of the price paths between time steps, a static demand curve is developed for use in the integrating model.

On the supply side, a linear programming framework provides a structure for the large number of interrelated activities and processes in the production, conversion, and transportation of energy. The optimizing capability of the linear programming simulates the cost-minimizing behavior of a competitive market.

The integrating model determines the equilibrium between supplies and demands. Because of the large number of relationships and the complexity involved on both sides, an iterative approach is used to balance supply and demand. Energy prices are used as the iterating variables.

Mathematical Formulation

The mathematical formulation of the PIES model cannot be characterized easily due to the large and multi-aspect nature of the model. Generally, the basic equations reflect the techniques used (that is, econometrics for demand and linear programming for supply).

Important Assumptions

The key assumptions in PIES are related to the structure of the model. These are that real energy supply can be represented properly by an optimizing model and that future energy demand is reflected accurately in the econometric representation. Assumptions of this nature, of course, are true of any model. More specific assumptions deal with determining the inputs required for addressing given scenarios and questions. These inputs are addressed in the next section.

INFORMATION FLOWS

Inputs

A large quantity of detailed data has been compiled to support PIES models. However, it is still necessary to specify inputs for particular scenarios. The inputs which the user may readily specify are summarized in Table F-II.

Outputs

Since PIES is very detailed, there are potentially a very large number of outputs available. Four sets of detailed reports are incorporated into PIES:

1. PIES Integrating Model Report;
2. International Energy Evaluation System Reports;
3. Regional Demand Forecasting Model Reports;
and
4. Oil and Gas Model Reports.

The integrating model report displays the important features of the PIES forecast in terms of consumption, production, conversion, and transportation at both the national and regional levels. The international reports display similar information for the international regions. The forecasting model reports show quantities of different kinds of fuels demanded by region and the United States for the years 1973 through 1990. The oil and gas reports display supply curves for oil and gas and their co-products as well as other detailed information about the industries.

ELECTRIC UTILITY ASPECTS

Modeling Approach

Electric utilities are considered in a separate supply model in PIES. The model conducts separate calculations for each of the utility regions listed in Table F-I. The function of the electric utility model is to use the demands indicated for that region and determine the cost of the supply for that demand. The mix of plants and fuels used to meet that demand is calculated on the basis of marginal costs. However, the cost to users is based on average cost.

Model Detail

The demand information supplied to the electric utility model does not indicate the nature of the load characteristics. This demand is apportioned arbitrarily to peak, intermediate, and base load. The model then calculates a least-cost mix of generation facilities to meet this load. Limits are placed on which type of capacity can supply which loads (e.g., gas turbines are for peak only, nuclear operates as base only, etc.).

A number of different types of generation capacity and fuel are considered:

1. Residual-fired steam turbines
2. Gas-fired steam turbines
3. Coal-fired steam turbines
 - a. High sulfur coal with scrubbing,
 - b. High sulfur coal without scrubbing, and
 - c. Low sulfur coal
4. Distillate-fired simple cycle gas turbines
5. Distillate-fired combined cycle gas turbines
6. Hydro
7. Nuclear
8. Solar, geothermal, and fuel gas

Generation facilities also are distinguished by age (new or existing). Transmission and distribution cost is calculated as a function of required generating capacity.

USES FOR REGIONAL ELECTRIC UTILITY PLANNING

Problem Class

PIES is a comprehensive model of the United States energy system which incorporates energy supply and demand for major energy forms. It emphasizes analysis of petroleum productions, but the large amount of detail should make it useful for electric utility considerations. The model is largely a policy analysis model. Thus, potential applications of PIES for electricity supply and demand are likely to lie in the policy analysis area also. PIES should be particularly suited for considering how policies proposed for other energy questions affect electric utilities.

Regional Class

PIES is designed for analysis of the United States energy system. It does include both regional disaggregation within the United States and international considerations. Regional applications are fairly well confined to the regions listed in Table F-I.

Time Frame

PIES has been used to project the state of the energy system in 1980, 1985, and 1990. This is indicative of the time frame for which it was designed.

TABLE F-I

Regional Definition in PIES

Demand and Utility Regions

1. New England
2. North Atlantic
3. Mid-Atlantic
4. South East
5. Upper Mid-West
6. South Central
7. Central
8. Mountain
9. Pacific, South
10. Pacific, North

Oil and Gas Supply Regions

- 1N. Alaskan North Slope
- 1S. South Alaska
2. Pacific Coast States
- 2a. Pacific Ocean
3. Western Rocky Mountains
4. Eastern Rocky Mountains
5. West Texas, East New Mexico
6. Western Gulf Basin
- 6a. Gulf of Mexico
7. Mid-Continent
8. Michigan Basin

TABLE F-I (Continued)

9. East Interior
10. Appalachians
11. Atlantic Coast
- 11a. Atlantic Ocean

Coal Supply Regions

1. Northern Appalachia
2. Central Appalachia
3. Southern Appalachia
4. Midwest
5. Central West
6. Gulf
7. Eastern Northern Great Plains
8. Western Northern Great Plains
9. Rockies

TABLE F-I (Continued)

10. Southwest
11. Northwest
12. Alaska

Refinery Regions

- 1a. North Atlantic
- 1b. South Atlantic
- 2a. Mid-West
- 2b. Northern Plains
3. South Central
4. Mountain
5. Pacific

TABLE F-II

Inputs for PIES

Import Prices and Availabilities Prices of imported crude oil, petroleum products, natural gas, and liquefied natural gas (LNG) may be specified by the user, along with import limitations, if any.

Resource Base Uncertainty regarding the extent and location of fossil fuel reserves is an important factor in energy market forecasts. Variations in the assumed resource base can be used to develop alternative optimistic and pessimistic forecasts.

Production Costs and Constraints Extra costs and production limitations can be specified to represent the impact of environmental or other constraints.

Macroeconomic Forecasts The economic forecast used to drive energy demand must specify regional levels of population, personal disposable income, and value added in manufacturing, as well as GNP and unemployment.

Conservation Programs The effects of conservation programs can be incorporated into PIESIM forecasts. Most programs require some preliminary partial analysis to be done off-line, the results of which are then used to modify projected demand.

Price Regulations Average cost pricing of electricity, oil price controls, oil entitlements, natural gas regulation and allocation, and pricing assumptions for LNG and synthetic natural gas (SNG) can all be part of the specification of market equilibrium conditions. In general, the implementation of oil or gas price regulation is carried out partly by the equilibrating mechanism and partly in the specification of oil and gas supply curves.

Taxes Taxes can be applied to any fuels at any point in the system.

Electric Generation Costs and Capacities A number of different items can be specified in the electric utility sector, such as construction limitations for new plants, restrictions on the fuels that can be used for electricity generation, load factors, and capital and operating costs.

Transportation Costs and Capacities Costs and capacities of transportation links can be modified to reflect environmental or other constraints.

Emerging Technologies Alternative assumptions can be made concerning the availability, cost, and penetration of solar and geothermal energy, both for direct use and in electric generation.

Figure F1.--Overall Structure of the Project Independence Evaluation System

APPENDIX G

STANFORD RESEARCH INSTITUTE ENERGY MODEL [20,21]

OVERVIEW

Model Functions

The Stanford Research Institute (SRI) energy model is a comprehensive supply/demand model for the United States. It is based on the economic concept of balancing supply and demand at a market clearing price. A complex network consisting of approximately 2400 links is used to simulate the production, processing, transportation, and use of energy. The network links 14 end uses in each of eight demand regions with 30 primary resources in 12 resource basins. This network, along with resource supply and end-use demand curves, results in thousands of market clearing prices, each specifying the economics of a fuel at a particular location and time.

Components

The SRI model is comprised of a large number of interconnected links, each of which could be considered a separate component. The model, however, can be divided into three distinct parts which may be referred to as components. These are a set of supply curves for resources, a set of demand curves for end uses, and the network links.

The supply curves were developed by holding costs and technology constant and using available data and the judgement of exploration and production specialists to estimate the quantity of a resource that ultimately could be recovered at various price levels. These curves describe the cost of production as the resource is produced and depleted. The curves are used to determine the prices required to sustain the additional production for the next time period. These prices then are adjusted for technological change, short-run dynamic effects, and economic rent.

The demand curves' nature is not stated clearly in the references cited. It appears that detailed price elasticities for end users could be incorporated into the model. However, the model, as it has been used, considers end-use demand to be inelastic and is specified by a scenario input.

The network of links is the core of the SRI model. The links describe the production, processing, transportation, and end use of energy resources. The principal elements of the network are

1. Locations where energy is produced, processed, or consumed;
2. Materials that contain energy, (i.e., coal, steam, etc.); and
3. Processes that convert or transport energy materials.

This network ties the supply and demand curves together to determine equilibrium values for prices and quantities at all points in the system.

Geographic Aspects

The SRI model was developed for the geographic region defined by the United States. Within the United States, eight demand regions, six refinery regions, and 14 resource regions are specified. These regions are listed in Table G-I.

MODELING TECHNIQUES

Specific Techniques

The core of the SRI model is the complex network of materials, processes, and transportation links. In all, there are approximately 2400 such links. An iterative scheme is used on the network to balance the large number of supplies and demands throughout the network simultaneously. A brief overview of the iterative scheme follows.

First, an initial estimate of primary resource production is made. The supply curves and information pertaining to price dynamics are used to calculate prices at each point in the network. At the end of the network, the result is prices for end-use energy.

Next, a pass is made in the opposite direction. The prices for end-use energy and the demand curves are used to calculate the quantity of energy demand for each end use. These energy quantities are passed back through the network with conversion and transportation losses being accounted for in each link. At the end of the

reverse pass, the quantities of resource production required are indicated. These values are used as starting conditions for another pass in the forward direction.

This back-and-forth iteration process is continued until convergence is indicated by no change in the quantities of resources produced between two iterations. This technique of network analysis should not be confused with linear programming. The equations are non-linear and usually unconstrained. There is no guarantee of convergence with the straight-forward iteration scheme outlined. In actual practice, additional procedures are required to ensure convergence.

Mathematical Formulation

The supply and demand curves are formulated fairly much in the traditional manner. The main difference is that the supply curves are formulated on the basis of ultimate production versus price, and the demand curves must specify end use rather than the energy form. The bulk of the model (the network of links) specifies the efficiencies, operating costs, and capital costs for a multitude of processes. These apparently are based on non-linear relationships. Time lags also are incorporated in the model to reflect the time required for real decisions to be made and for the system to respond.

Important Assumptions

There are a number of structural assumptions built into the SRI model. These are listed in Table G-II. In addition, it is assumed that end-use demands are relatively inelastic compared to supplies.

The supply curves and demand also should be considered assumptions. The supply curves are based largely on expert judgement. Demands are based on projections made in other studies.

INFORMATION FLOWS

Inputs

The two major inputs to the SRI model are the supply curves and the demand curves. Also, a considerable amount of detailed economic and technical information is used in describing the individual links in the network. Presumably, the supply curves used for previous studies also could be used for future studies. Users may want to change some of the curves for particular studies; but generally, the curves should be suitable for other areas of study. The studies made previously have assumed an inelastic demand and have used projections made in other studies to determine end-use demands. Any studies which would need to consider price effects on end-use demand would require the development of demand curves.

Outputs

The outputs of the model are prices and quantities throughout the system for the time period simulated. The tremendous level of detail represented by the network also is reflected in the output. The price and quantity at the end of each of the 2400 links is, at least in theory, available as an output. Generally, the output will concentrate on the production of energy resources in each of the resource regions shown in Table G-I and the consumption of the energy in each of the demand regions.

ELECTRIC UTILITY ASPECTS

Modeling Approach

The SRI model was not constructed specifically for electric utility studies. Generation of electricity is just one of a number of energy conversion processes considered in the network. Thus, there is a relatively simple electric utility component for each of the regions in the model.

Model Details

Electric energy demands are represented by a discrete load duration curve consisting of base, intermediate, and peak demands. It is assumed that the energy is divided among these categories in the proportions of base--71 percent, intermediate--24 percent, and peak--5 percent. These proportions are assumed for all demand regions. However, different, constant-load factors are specified for each load category for each of the eight demand regions. These load factors are selected to be consistent with the overall load factor for the region.

Four basic types of power plants are considered for detailed economic calculations:

- conventional nuclear;
- coal-fired boiler;
- combined cycle using low Btu syngas; and
- oil-fired boiler.

The economics of all other types of plants are estimated relative to these basic plants. The relative economics of the various plants (based upon fuel, capital, and operation costs) determine how many of each will be built and used in each region. Hydroelectric generation is not considered in the model.

USES FOR ELECTRIC UTILITY PLANNING

Problem Class

To date, the model has not been used specifically for electric utility planning studies. It has been used mainly for analysis of synthetic fuel commercialization and western resource development. The tremendous detail in the model should make it useful for a wide range of additional energy studies.

The documentation referenced does not indicate specific electric utility planning applications. However, the SRI model should have several useful applications. The model is able to consider the entire United States on an inter-regional basis and determine the energy prices in any one of the eight demand regions. This should prove useful in planning for generation capacity and fuel mix. The inter-regional nature of the model allows it to show how what is happening in one region in the United States affects the energy situation in other regions. It should be particularly useful for indicating the impact of government regulations on specific regions.

TABLE G-I

Regional Definition in SRI Model

Demand Regions

New England
Middle Atlantic
South Atlantic
East South Central
West South Central
East North Central
West North Central
West Coast

Refinery Regions

Philadelphia
Gulf Coast Port
West Coast Port
Chicago
South East Port
West North Central

Resource Regions

Powder River Coal
Southern Illinois/Western Kentucky Coal
Appalachia Coal
South Alaska Oil and Gas
Midcontinent Oil and Gas
Pacific Coast Oil and Gas
Atlantic Offshore Oil and Gas
West Texas Oil and Gas
North Slope Oil and Gas
Rocky Mountain Coal, Oil and Gas
Gulf Coast Oil and Gas
Artificial location, point of origin for imported fossil fuels
Artificial location, point of origin for nuclear fuels
Secondary material location

Regional Class

As noted above, the SRI model is an inter-regional model for the United States. The model should be applicable to studies involving any of the specific regions listed in Table G-I.

Time Frame

The object of the model is to explore the impact on the structure of the energy system as resources are depleted and costs increase. As a result, the time frame is somewhat longer than most of the other models reviewed. The projections extended through the year 2025 for the studies discussed in the references.

TABLE G-II

Structure Assumptions in SRI Energy Model

Gas and oil prices are not regulated.

All prices are marginal, not average (including electricity).

Technologies are selected on the basis of economic and behavioral considerations including lags and other "inertia" effects.

Internalized environmental costs (cost of compliance) are included based on current standards.

Residual environmental costs (externalities) are not included.

No quotas or rationing of imports are assumed.

Import prices are exogenously specified.

Demand for useable energy is exogenously specified.

No new restrictions are imposed on direct burning of Western coal.

A stable investment climate is assumed.

A stable long-range U.S. energy policy is assumed.

APPENDIX H

WISCONSIN ENERGY MODEL (22,23,24)

OVERVIEW

Model Functions

The Wisconsin regional energy (WISE) model was developed to describe the technological, economic, and environmental interactions in the Wisconsin energy system. Designed to be the framework for studying specific energy questions in Wisconsin, the WISE model contains submodels for all parts of the Wisconsin energy system and addresses the economic, demographic, and environmental relationships to the energy system. Since Wisconsin has almost no primary energy resources, little attention is given to energy resource production.

Components

Figure H1 gives an overview of the structure of the WISE model. The price feedback mechanism shown in this figure currently is not implemented but is being developed. The other five components to the model are socioeconomic activity, end-use energy demand, energy conversion and supply, environmental impact, and external energy supplies and prices. Each of the components is described briefly in the following paragraphs.

The socioeconomic component uses a set of submodels to provide information on socioeconomic activity distributed spatially across the state. An age-, sex-, and county-specific model is used to project population. Economic activity is defined largely by exogenous variables such as value added in manufacturing, wholesale, and retail sales, receipts to service industries, and government expenditures. Various types of manufacturers are defined and separated according to the SIC system. A part of economic activity is related directly to population with value added per capita or similar parameters.

End-use energy demand is divided according to physical process, economic sector, and fuel type. The transportation model consists of three smaller models: passenger-auto transport, inter-city transport, and freight transport. Urban mass transport is included in the passenger-auto transport model. The demand for transportation derives from the population and

industrial models. The industrial energy model is simply a series of parameters which relate the energy of each type required to the level of output of each sector. Work is underway to allow more consideration of fuel substitution within this scheme. The residential energy model focuses on energy use in the home. The type of home and the ownership of appliances are used to determine residential energy demand. Commercial energy demand can be determined by one of two parallel models. One is linked to economic activity as in the industrial energy model. The other is based upon engineering design procedures. The agricultural energy demand model is divided into crops and livestock components. The resulting energy demand is divided further into direct and indirect energy use.

The energy conversion and supply model mainly considers energy supplies to be time-dependent, exogenous functions of energy prices and availabilities (since Wisconsin imports nearly all of its fossil and nuclear fuels). The model does include storage and transportation systems. The electricity industry is the only energy supply modeled in detail.

The environmental impact model assesses the impacts associated with primary energy sources, energy conversion and supply sectors, and end-use demands. It treats effects both within and outside of Wisconsin. Environmental impacts include effects on land, air, water structures, and living things. An effort has been made to quantify as many impacts as feasible.

The cost and availability of gas, oil, coal, and nuclear fuels are provided as exogenous inputs. This information is stored in a data bank.

Geographic Aspects

The WISE model was designed for the state of Wisconsin. In the model, the state is subdivided into the 72 counties. Most results are presented on a statewide basis or according to eight districts within the state. The model addresses energy questions only within state

boundaries. However, environmental impacts related to energy use are considered both within and outside of Wisconsin.

Although the WISE model is designed specifically for Wisconsin, the methodology has been applied to other regions. It provided the basis for a cross-regional comparison of the energy/environmental systems of Wisconsin, the Rhone-Alps regions of France, and a region of the German Democratic Republic. This work was carried out at the International Institute for Applied Systems Analysis, Austria. The methodology also has been used to address energy questions in other states in the Upper Great Lakes area.

MODELING METHODS

Specific Techniques

A variety of modeling techniques is used in the WISE model. It contains of a collection of submodels programmed in FORTRAN, each of which describes a different aspect of the energy system. The overall structure of the model is dynamic simulation. However, individual submodels may use a variety of techniques. For example, the livestock submodel uses a linear programming approach to calculate annual livestock populations. Consideration is being given to utilizing input/output techniques in the economic model. All that is required of an individual submodel is to be able to simulate its part of the system on an annual basis.

Mathematical Formulation

Although a large degree of flexibility exists, the dominant method used in formulating the model is one of parameters. Important variables are related to other variables mainly through the use of constant parameters. Industrial energy demands are linked to levels of output by energy intensiveness parameters, environmental impacts in each sector are related by parameter to the amount of each type of energy used, etc. It appears there will be less use of simple parameters as the model continues to develop. Work is proceeding in several submodels to base relationships on engineering and economic analyses.

Important Assumptions

It is virtually impossible to list the assumptions used in the WISE model without going into details of the formulation of each component. Probably the most important assumptions for most studies deal with the price and availabilities assigned to fossil and nuclear fuels imported into the state.

INFORMATION FLOWS

Inputs

The main inputs to the model are the availability and cost of fossil and nuclear fuels which are imported into Wisconsin. These include natural gas, oil, coal, and nuclear fuel used in high-temperature gas reactors, light-water reactors, and liquid-metal fast-breeder reactors. A data bank is programmed into the model which can be used to supply this information.

A second important set of inputs is required to drive the models in the socioeconomic component. Economic activity normally is represented by variables such as value-added in manufacturing, wholesale and retail sales, receipts to serve industries, and government expenditures.

Outputs

There are two major outputs from the WISE model: the energy use in Wisconsin and the environmental impact of producing and using this energy. The energy outputs can be given at the county level but normally are aggregated to an eight-region level or are given for the entire state. The energy use output is specified by fuel type, physical process, and economic sector. The environmental outputs consist of quantifiable impacts the use of energy in Wisconsin has both inside and outside of Wisconsin's borders. All processes involved in energy resource production, conversion, and transportation resulting from energy use in Wisconsin are considered. The main environmental outputs are disturbed land, water consumption, and emitted pollutants.

A number of intermediate calculations are performed in the various submodels that give results which could be tapped as outputs if desired. For example, the amount of electric generating capacity constructed for a given set of conditions could be determined.

ELECTRIC UTILITY ASPECTS

Modeling Approach

Electricity supply is a separate component of the WISE model. It is one of the more detailed submodels of the entire model and is the only energy supply sector modeled in detail. Transmission, distribution, and generation capacity are modeled in separate submodels. The transmission and distribution model provides an overall picture of future costs for transporting electricity to end users. The generation capacity submodel provides a basis for studying the effects of plant expansion strategies.

Model Detail

Transmission and distribution can be modeled fairly simplistically by relating them to generation capacity using historical parameters. A more complex model for transmission and distribution also can be used. This model uses hypothetical geometric load-source patterns to forecast the transmission requirements for various alternative energy futures. A distribution routine separates the statewide energy demand into eight load density regions. This information, along with the number of customers, is used to calculate the cost for added transmission and distribution.

The electric generation model performs three functions:

1. Converting kilowatt-hour demand requirements from end-use demand sectors into equivalent generating capacity requirements using load duration analysis;
2. Simulating the satisfaction of these requirements by adding capacity to the system with the particular capacity added being dependent upon fuel availability, prices, and technology; and
3. Calculating costs over the simulation period including capital costs for new and existing generation plants, the appropriate fuel costs, and operating costs.

The focus of the generation capacity model is capacity expansion. Three capacity expansion options are available to the model user:

1. An external option where the user specifies the capacity to be added during the simulation;
2. A specified time dependence of the nuclear fraction in the plant mix with the amount of capacity required being determined from demand levels and a load duration curve; and
3. A combination of these two schemes.

The model simulates the retiring and derating of capacity as it ages. The model also includes an iterative procedure where the impact of electric utility expansion affects electricity prices. These prices affect the quantity of electricity demand which, in turn, affect the need for capacity. The iteration procedure allows the system to be balanced so that demand and capacity installed are consistent.

USES FOR REGIONAL ELECTRIC UTILITY PLANNING

Problem Class

The WISE model is primarily a framework to allow assessment of a wide range of energy problems in Wisconsin. It has been applied to several energy questions in Wisconsin which do not address electric utilities specifically. These include:

1. determining if the goals of President Carter's proposed national energy plan would be achieved in Wisconsin if implemented;
2. the impact in Wisconsin of primary fuel diversions; and
3. the energy saved by shifting to smaller autos, more energy efficient autos, and greater use of mass transit.

The applications of the model specifically addressing electricity supply questions have been made:

1. The energy saved and the effect on generating capacity requirements which would result if the average efficiency of air conditioners was increased by 40 percent; and
2. The additions in generation capacity and transmission and distribution systems required in the future under low, medium, and high economic and population scenarios.

These applications are indicative of electric supply uses for the WISE model. The model also may be useful in addressing regulation and control questions.

Regional Class

The WISE model was developed specifically for the state of Wisconsin. The methodology employed in the WISE model has been applied successfully to other regions including other states in the Upper Great Lakes area, the Rhone Alps region of France, and a region in the German Democratic Republic.

Time Frame

The time frame for which the WISE model seems appropriate is through about the year 2000.

Figure H1.--The Wisconsin Regional Energy Model Structure

APPENDIX
OF
Stagg Systems Inc.

DESCRIPTION OF SYSTEMS

INTRODUCTION

A conceptual framework for an ideal system of interactive graphics applications is shown in Figure 1. The figure depicts the foundation blocks supporting the application of a specific user and shows the two essential components, a data base system and a graphics system.

In an ideal sense, the successful application of technology rests upon the availability of the four components represented in Figure 1. In actual situations varying degrees of emphasis have been placed upon the four building elements idealized in Figure 1. In some instances no effort is made at all to identify components along the lines of the demarcations shown. Some of the fundamental needs in the areas of graphics are:

- A primary capability to manipulate and depict data with an evident visual impact
- A lesser capability to accept graphical data as input to a process

Some of the fundamental needs in the areas of data bases are:

- a capability to initialize a data base in a structured form
- a capability to access, edit, and restore data assemblages conveniently.

Applications Systems

An essential point to be recognized is that the four elements noted as the building blocks are not the end product. The end product instead is the application of these blocks in permitting development and utilization of planning systems. Ideally they would be available and used in a natural and flexible fashion.

Within the electric power industry a number of tools have been devised for use in computer-based interactive graphic planning systems. Interest in the industry, however, has focused on one specific planning tool, used almost universally by any agency performing power industry expansion planning. The steady state simulation of the electric power network subject to various growth alternatives is a capability available to almost all companies. To a much lesser extent it is

available in an interactive mode.

Within the DOE laboratories, quite a different situation exists, largely as a result of differing perspectives regarding planning. As a result of the needs to provide impact analysis studies and to perform regional resource planning DOE studies have been considerably more diverse. Typically the studies conducted by DOE laboratories focus on:

- regional water quantity studies
- regional water quality studies
- air quality studies
- generation siting studies
- transmission siting studies
- land-use analysis studies
- coal resource data analyses
- coal mining impact analyses
- aesthetic impact analysis
- mineral lease studies
- socio-economic impact analyses
- waste repository analysis

Importantly such studies have not generally been performed in the context of a systems approach. Instead they are attempts to provide alternative solutions or answers to some specific requests at a political level.

Graphics Systems

While Figure 1 shows a specific line of demarcation between graphic interactive systems and graphic equipment support systems there exists a variety of packages which in some fashion infringe upon the graphics areas and cover different parts of such systems. The intent in Figure 1 is to separate the program systems used to cause the graphic devices to perform their capabilities from the program systems which operate at a higher level and accommodate user interaction more fully.

Perhaps the best manner in which to emphasize this distinction is to identify with the graphic equipment support, those program systems generally available from equipment suppliers which provide a rudimentary capability to make use of the facilities inherent in the equipment. These may be referred to in the technical literature as input/output drivers, basic access methods, or graphic support packages depending upon the jargon of the manufacturer.

At an entirely different capability level lies the facility to interactively make use of the lower level systems and equipment. Such higher level capability incorporates the joint needs of the user

and the equipment to make available a synergistic environment in which the attributes of the equipment are fully accessible to a planner. Such systems are more truly systems and may be typified by several of the available DOE projects such as CHART and CARTE described later in this paper.

Frequently in a DOE facility several alternative pieces of equipment may be available to produce graphic results. An especially useful capability of program systems in such an environment is device independence in which any of several available devices may be used on an alternative basis without reprogramming. This is a highly desired feature of graphic systems and has to some extent been implemented in DOE laboratories.

Graphic systems frequently address the basic problem of presentation of data in a graphic form for easy assimilation. While this is a primary aspect of graphic systems, other important aspects are the need to make data available, the need to manipulate graphic representations, and the need for good man/machine dialogues.

Data Base Systems

Almost of equivalent concern in graphic-based systems is the availability of a good data base management facility. Most modelling systems require the availability of a reliable supply of data. More to the point is a need to have access to data which then may be conveniently manipulated and restructured.

Very many data base management systems are available on the market place today. In several instances these have been purchased or licensed to DOE facilities for use. In turn they have been used for preparation of data bases which vary in size.

Significant data base development has occurred and is continuing at various DOE facilities. In some ways these developments are being conducted with a planned approach while in other instances data bases are being devised in a more ad hoc fashion contingent upon the needs of a specific study.

At the DOE laboratories there is no consistent pattern for data base development. Generally they tend to be somewhat fragmented. There is, however, some measure of sharing which facilitates data editing and updating by a group or person other than the originating agency.

A further use of graphic systems in this regard in the editing of data by means of interactive graphics systems.

The following are among the data bases identified by DOE facilities as being available or under development.

- population, migration, census, housing, county, city, geocoded data
- geographic data, air quality stations, map files
- business enterprise, growth models, input/output models
- employment-occupation data
- labor force data, earnings
- transportation data
- agriculture and food data
- human health, somatic and genetic effects
- environmental and resource data
- societal and economic data

DOE Laboratory Emphasis

Several capabilities which are dominant in individual laboratory facilities have become evident in field visits. A brief list of the noteworthy capabilities is given below:

Argonne National Laboratory

- device independent graphics
- research and use of automatic scanning systems

Lawrence Berkeley Laboratory

- comprehensive monitor system of programs
- data base development
- interpretive graphic systems

Oak Ridge National Laboratory

- individual planning systems
- building block approach to graphic support systems

Recognition should be given to the multiagency responsibilities of the individual laboratories and the role which individual project funding has on the direction of laboratory activities. Laboratory activities include projects for the Department of Energy, Department of Labor along with other Federal level agencies, and state and regional agencies.

OVERVIEW OF ELECTRIC UTILITY INDUSTRY SYSTEMS

A number of application systems are available within the electric utility industry. For the sake of discussion within this paper the industry may be considered to be composed of both the private and public sector as well as regional groupings and the related consulting industry. All of these agencies participate to varying degrees in the different aspects of the planning process.

While planning application systems are available to a moderate extent within the industry, the utilization of interactive graphics is relatively low within the available applications.

Several stratifications are evident within the total range of applications. These stratifications may take place across several lines.

One stratification addresses the specific areas of application:

- generation system planning
- transmission system planning
- energy supply/demand model analysis.

A variety of applications are in existence and in use within each of the three areas identified. A survey conducted by The University of Oklahoma as part of this project revealed the following major applications within the categories:

Generation Planning Models

- Production Cost Analysis
- Loss of Load Probability Analysis
- Economic Dispatch - Unit Commitment Analysis
- Optimum Generation Expansion Planning
- Financial Simulation of Expansion Plans.

Transmission Planning Models

- Load Flow Analysis
- Short Circuit Analysis
- Transient Stability Analysis
- Optimum Real/Reactive Power Flow Analysis
- Transfer Limit Analysis
- Optimum Transmission Expansion Planning
- Investment Cost Analysis
- Loss Formula
- Distribution Factor Analysis

Energy Supply/Demand Models

- Load Component Data
- Load Forecasting

- Statistical Data Analysis
- Econometric Data Analysis

An alternative stratification indicates more clearly the form of the analytical work performed within the individual application areas. They may be categorized as follows:

- stochastic models
- optimization models
- network simulation models
- financial models

Table 1 is an augmented list of applications and indicates the area an application fits into as well as the form of the analysis.

The applications systems identified above have predominantly been developed by the industry with specific industry needs being the motivating factor. In most cases more than one implementation exists owing to varying needs, although the basic application may be very similar across many of the companies.

It should be pointed out that the identified applications relate to traditional utility industry planning conceptions insofar as the scope is concerned. Relatively little published material is available describing applications of present day concerns such as environmental aspects, regional resource utilization, and newly imposed constraints by various regulatory agencies.

A review of the utility industry technical literature reveals a single application system as having had substantial interactive graphic development. The development of an interactive graphic capability has progressed in several alternative forms and in various implementations for the load flow application [1], [7], [8], [9], [23], [24] [28]. This steady-state simulation program is used more extensively than any other within the industry and consequently has much interest focussed upon it.

Generally the application consists of: a calculation capability for large network simulation; a data base of alternative network configurations for different years, load levels, and plans; a reporting capability to render desired detail or summary results; and an interactive terminal to enter data, review results, and initiate studies.

It has been implemented for small dedicated computer systems as well as for large scale general purpose compute

systems. Of especial interest in such systems in the use of color video monitors with light pens which allow a planner to interact with network diagrams on the video monitor. Such interaction involves depiction of new power system facilities (generators, transmission lines), updating of data files regarding alternative facilities, simulation of the impact of such facilities, and graphic review of the results of such simulations.

Significant developments have been made in the interactive load flow program development. Utilization of this relatively new development, while limited, is expanding. Corresponding development in other application areas has, however, not been made. While other applications make some use of graphics capabilities, the capability most often is used sparingly to depict the results of calculations in a graphic manner. Very little use is made of interaction in these cases and generally results are prepared in a batch processing mode for hard copy depiction by means of plotting equipment.

DESCRIPTION OF SYSTEMS AT ARGONNE NATIONAL LABORATORY

As at other laboratories which were visited, and at several from which documents were obtained, a wide variety of graphics output devices is available at Argonne National Laboratory (ANL). Along with the equipment is a significant supporting program system capability which affords the user an opportunity to make use of the equipment.

The equipment available includes computer printer, mechanical pen plotter, micro-film recorder, electrostatic plotter, video display units, and a dedicated computer-based digitization system.

Especial emphasis is made at ANL to make users aware of the benefits of device independent graphics. In addition, a number of graphics support program systems are made available to users of graphics devices to facilitate equipment utilization. These include commercially developed systems and ANL-developed or enhanced systems.

One aspect of the approach to computer interactive graphic systems at ANL is to make the graphic output devices conveniently accessible to users. Such use does not in general involve significant interaction to the extent that the user may observe graphic results in an on-line mode and interact with programs to "fine-tune"

graphic results or to request additional studies to produce alternative sets of results. On the other hand, it is evident from discussion with ANL staff that such capability would be desired.

The extent of major applications of interactive computer graphics for regional planning at ANL appear to be restricted to several which make use of computer graphics output terminals for preparation of graphic representation of results. A more significant use of the computer graphics capability at ANL is in the coding of specific programs to prepare required plots or depictions of data. Thus there does not in general exist an integrated program consisting of regional planning models with graphic depictions of the results of a simulation. Instead specific data displays are coded for the ad hoc purpose or request.

ANL Applications

Siting Studies

One application at ANL is identified under the acronym SITE and includes both a methodology and a computer program for assessment of energy facility siting patterns. The SITE Methodology [51] is a computerized one which allows screening of alternative energy facility sites within an electric utility region. It also allows evaluation of the impact on a region of alternative energy supply configurations.

The site methodology is based upon consideration of three major siting factors.

- . the cost vector
- . the impact vector
- . the site attribute vector

The methodology for site selection considers a variety of factors relevant to generation facilities. Reference [51] contains a comprehensive list of such factors.

The SITE methodology development appears to have been directed to an evaluation on a site-by-site basis. The methodology is extended, however, to regional assessment of energy facility siting options.

It appears that the SITE methodology as presented in published material is undergoing continued development. While some applications programming is available and some graphical results of analysis are depicted, a comprehensive automated process

for specific sites or for regional assessment is still in the formative stages of development. It does, however, offer a pragmatic and realistic approach to site selection.

Automated Scanning System

An Image Processing System (ALICE) [74] is operational at ANL and has been used for several applications, although not primarily in the regional planning process. The ALICE system is a dedicated system devised to process images as input to the system. This is quite different from most other facilities discussed in this study which are more directed to preparation of graphic results. ALICE is directed primarily to digitization of visual, graphic, and mapped information.

The system makes use of a dedicated computer and two special sets of equipment to facilitate processing.

- vector cathode ray tubes for man-machine interaction with scanned data
- optical scanning stations for a scanning light microscope, reflected light scanner, and for film scanning.

The application for which the ALICE system has been used which most closely impinges upon the regional planning process is the digitization of soil data for use in environmental analysis, and for city planning purposes.

Coal Resource Data

During conversations at ANL attention was directed to a data base which is being developed for the assessment of strip mining of coal resources. Such a data base is being constructed for one specific regional project. Also available from the data base is the capability to plot coal seams.

ANL Data bases

Nuclear Plant Site Data

The Information on Nuclear Sites (INSITE) system [53] was developed at ANL specifically for the Nuclear Regulatory Commission. It is an information retrieval system which contains design, siting and environmental impact data for existing and planned nuclear generating units.

The user of INSITE may request data from the data base in an interactive mode at a terminal by selection of categories, descriptors or elements, each of these allowing penetration through different levels of detail to one or more specific data items. The user may also request information on a subset basis as, for example, a request for nuclear unit names within a given state.

The INSITE data base contains almost three hundred thousand data items for all U.S. commercial nuclear plants docketed by the end of 1975. During discussions at ANL it was noted that the system is no longer operational on an interactive basis, but instead the data base has been made available to a variety of users as a data base.

ANL Support Programming Software Systems

A Graphics Software Package

A graphics software package (MYPLOT) [49] is available at ANL to facilitate the preparation of plots of data. The package allows preparation of xy plots, histograms and bar charts with annotation and special scaling as required. The package also contains a capability for least-squares curve-fitting. Output results may be directed to mechanical plotters, microfilm recorders or graphic video terminals.

The ISOMERGE Program

The ISOMERGE program [49] merges data arrays which map onto a common space or base array covering the space. The general purpose plot package then calculates and plots isopleth values of the base array. This program was used in the regional studies of power plant siting to perform mapping of statistics and to plot, on a common reference frame, the isopleth values of air quality.

General Purpose Programs

At ANL a variety of other software graphics packages [49] are available. Some of these are proprietary packages and support graphic presentation of data including: xy plots; pie and bar charts; shading and cross hatching; map projection; perspectives; contours; and solids and hidden lines. These packages support various devices available at ANL.

DESCRIPTION OF SYSTEMS AT LAWRENCE BERKELEY LABORATORY

A major area of development at Lawrence Berkeley Laboratory relates to interactive computer graphics. Significant efforts are being made and resources directed to providing interactive computer graphic capabilities to prospective users of graphic equipment. Personnel are available to perform development work. Various types of graphic equipment are available along with the required computational capability. All of these types of resources have been focussed on the development of tools available for user studies.

The primary area of emphasis appears to be in the development of a comprehensive integrated system with a variety of capabilities. The Socio - Economic - Environmental - Demographic Information System - (SEEDIS) is a framework within which many graphic and data base capabilities are available.

At the same time efforts are being made to stimulate use of available systems. Such stimulation stems in part from a desire to utilize available capabilities and also a desire to support continued expansion of the system from the budget of several funded projects.

At LBL extensive capabilities are available in terms of equipment, support software and data base software. It appears that less capability is available, however, in applications of these combined resources. The application studies make relatively sparing use of the available interactive graphic capabilities.

The equipment available at LBL includes: computer printer; mechanical plotter; graphic video display terminals; alphanumeric video display terminals; microfiche and microfilm recording unit, and digitization system. These are supported by large scale computer systems and by mass memory storage capabilities.

LBL Applications

Several applications are identifiable at LBL although in these applications little or no use is made of interactive graphic display systems. The regional planning applications which became evident during discussions with LBL staff and in a review of LBL documents centered on the following areas:

- air quality studies
- coal utilization studies

- national energy policy assessment
- drought-altered electricity supply and demand
- geothermal impacts assessment

Air Quality Studies at LBL

One application of interest in which modelling is performed is that of air quality analysis. An air quality modelling system [49] was developed at Lawrence Livermore Laboratory for use at LBL. The model is a sophisticated one which simulates the transport and chemistry of inert, reactive and photo-reactive compounds. The model includes extensive data for topography and for meteorology (wind fields). Supporting systems are available to automatically prepare meteorological data from observed data. Specific models have been prepared for the San Francisco Bay area and for the St. Louis area.

The regional air quality modelling system allows graphic results to be prepared. Results are given in terms of concentrations of atmospheric pollutants.

Coal Utilization Studies

An application currently undergoing development [73] is directed toward coal utilization assessment. The aim of the application is to define resource requirements for construction and operation of facilities making use of coal within the framework of the National Energy Policy. The impacts on manpower supply and capital resources are to be evaluated.

An energy supply model is used to determine direct requirements for capital and manpower by facility type. Indirect requirements for these resources are obtained using a national input-output model and an occupation-by-industry data base tied to the energy supply model.

In 1977 an interim report [37] was issued which described a study of the impacts of future coal use in California. The report described a methodology and the results of an assessment of impacts of future coal use. The assessment is a part of the National Coal Utilization Assessment being performed cooperatively by several laboratories. The basic requirement of the assessment is to evaluate the impacts of four coal utilization alternatives for a period up to the year 2000. The alternatives basically reflect different levels of coal utilization and application of different coal utilization technologies.

within the framework of the methodology several models were used as parts of the overall analysis of impacts. Significant statistical data is utilized to describe current energy supply systems and fuels. Models are used to reflect the direct impact of the application of coal technology to obtain fiscal and manpower requirements for both construction and operation. Models are also used to reflect indirect costs.

A comprehensive analysis is made for residuals showing pollutant effects due to coal-related facilities. Siting is evaluated. Air, water, emission, and health and safety factors are evaluated. The study presents a comprehensive review of many aspects of energy supply systems. It should be noted, however, that no discernible use is made of computer graphics although extensive use appears to be made of computer capability.

Drought Altered Electricity Supply and Demand

A study report [34] was issued in 1977 summarizing the evaluation of the impact of the California drought of 1976-1977 on electricity supply and demand. Agricultural, residential and industrial electricity demands were evaluated along with the supply available to meet these demands. The effect of water shortages on both electricity supply and demand were evaluated. A loss of load probability analysis was performed.

While this study was quite comprehensive insofar as its objective is concerned, it does not appear that any use was made of graphic depiction of results of the analysis.

Geothermal Impact Assessment

A study [73] is currently being conducted to analyze the socioeconomic factors associated with exploitation of geothermal energy sources in California. The study is to identify the local economic impacts, the issues and any constraints in the development.

LBL Data Bases

Major efforts have been underway at LBL for preparing, obtaining and refining data bases. Such data bases are prerequisites for many of the regional studies performed. The data in such data bases [38] includes data in the following

categories:

- demographic and social data
- geographic data
- employment data
- labor force, employment and earnings data
- transportation data
- agriculture and health data
- business enterprise data
- environmental data
- human health data

Estimates of the net volume of these files total in excess of ten billion characters of computer processable data.

Capability is designed into the SEEDIS monitor to allow access of some data base components conveniently by several of the processing programs operational under the system, thus relieving the user of some data base preparation and knowledge of details of structure. In addition a processing program is available to create, convert and edit data into and out of the standard mapping format at LBL.

Within the data bases themselves, there are some input-output models. Data is available for:

- 1972 U.S. Input/Output Table, 404 Sectors
- 1972 California Input/Output Table, 404 Sectors
- 1971 Energy Use, 5 Energy Types, 367 I/O Sectors
- 1968-1969-1970 U.S. Input/Output Tables, 67 sectors
- 1967 Western States Input/Output Tables, 367 Sectors
- Various Years of Input/Output Tables For Interindustry Transactions
- Various Years of Input/Output Tables For Direct Industry Requirements

In addition, for mapping purposes, a number of files are organized on the basis of census tracts, SMSA (Standard Metropolitan Statistical Areas), counties, and FIPS Codes (Federal Information Processing Standard).

LBL Support Programming Systems

The most evident development at LBL from the perspective of this study is the unique development in the area of supporting systems for computer interactive graphics. These along with the continue extension of the Socio - Economic Environmental - Demographic Information

System make available to applications tasks at LBL a formidable capability.

Socio - Economic - Environmental - Demographic Information System

The SEEDIS project is a comprehensive computer based information system [31], [39], [58], [73] making available various data bases, data base management tools, graphic interface programs, and an interactive monitor system allowing access to supported capabilities from a terminal. The SEEDIS project has benefited from funding support by a variety of projects which operate within the framework of the SEEDIS system.

The SEEDIS monitor is an executive portion of the system which supports the interface between the user and various facilities within the system. The monitor also operates as an interface to the user at a conversational terminal and allows access to processing programs and various component data bases. The monitor allows communication with users at various types of terminal units including alpha-numeric and graphic terminals.

The user may enter the SEEDIS system, request specific facilities (processing programs and data sets), operate upon the data and upon completion return to the monitor. Various graphics processors are available and results of these processors may be routed to a variety of graphic devices. By March 1975 it was estimated that 25-man years of effort had been expended in SEEDIS development.

While a variety of data base and graphics interactive tools are implemented the following descriptions highlight only the most significant. The capabilities included in the system are:

- graphic display and analysis
- report generation
- data base management tools
- thematic mapping
- data base access of a variety of data bases

Data File Creation (DOBEDO)

A data file creation program [39], [71] is available for interactive use to allow preparation of data for a polygonal mapping activity. The DOBEDO program organizes data appropriate to a polygonal entity within the framework of the Berkeley Data Base Management System (BDMS). The program allows user specification of data

variables to be assigned to given physical map tracts and creates a structure appropriate to utilization by the thematic mapping system CARTE described later.

Map Data Editing (MAPEdit)

The MAPEdit processor [39], [49], [71] allows a user to retrieve geo-encoded polygonal data pertaining to a specific entity. Such data is available for census tracts, counties, SMSA areas, and states within an LBL data base available within SEEDIS. The user has flexibility, within the MAPEdit processor, to retrieve data stored in files on a selective basis.

The MAPEdit system performs selection and restructuring of geographic data specifically for use by the thematic mapping system CARTE.

In addition the user has the ability to edit and update graphic files produced by MAPEdit by use of an editing processor [39], [49] ZING. This processor allows interactive editing of cartographic data, such as revision of points, lines and polygons, and creation of new polygons. Such editing may be performed with graphic video terminals.

Graphics Display Program CARTE

The confluence of processing by the programs DOBEDO, MAPEdit and ZING is the CARTE program for preparation of thematic maps. The CARTE program [39], [70], [71] obtains statistical data and geo-encoded data from the preprocessing programs noted, makes use of user-specified directives regarding the shading of geographic areas, and produces displays on microfiche, microfilm, and on video display terminals.

The facilities of CARTE are available both as a computer task submitted remotely, or interactively. The interactive mode has a broad capability to allow a user at a video graphic terminal to prepare directives for alternative display formats and to directly view the display.

In addition to the preparation of geographic maps, CARTE allows preparation of tabular reports of data and preparation of symbolic displays corresponding to cartographic data. For example a set of symbols may be displayed with each symbol corresponding to a given map entity and displayed with attributes (shading) consistent with the map data.

Interactive Analysis and Display of Tabular Data-CHART

The CHART system [35] allows a user to prepare tabular and graphic displays in a highly interactive fashion. The system operates with tabular data and allows the user to prepare reports, of a semi-graphic nature, such as tabular data, bar charts, line graphs, and pie charts. The system supports basic arithmetic functions to scale tabular data and to symbolically present measures of tabular data.

The system is highly interactive and operates within the SEEDIS monitor system or on a dedicated computer. The terminal interactive devices supported include alphanumeric video terminal, graphic video terminal, microfiche unit and mechanical plotter.

The system is an ideal one for preparation of charts. Capability is provided to reorganize tabular data by rows or columns in accordance with operators such as ranking, sequencing, grouping or by arithmetic computations. The basic data or the reorganized data may be presented directly or the data may be used to scale more graphic representations.

The user may annotate and structure the format of a given report of CHART in a highly flexible manner interactively. An interactive language is available to facilitate user interaction and to allow the use of various operators.

Meteorological Data (UADATA) and Air Pollution Data (GRAY) Display

Two systems are available [49] for depiction of data pertaining for air quality studies. The UADATA system displays meteorological observations. These include surface and elevated wind vectors, temperatures, dew point, solar radiation and other recorded values on a map of a given study area. The GRAY system provides displays of emission sources on gray level plots and contours on a map of a given study area. Both of these systems are ideal for data base analysis and support the use of a variety of graphic devices by means of a common graphic device interface program.

Other Available Programs

While the foregoing has highlighted a number of significant graphics support programs there are other [49] available at LBL. Some of these are primarily

supporting graphics packages; others provide the capability to perform statistical data calculations; others provide convenient access to data files for text editing. They are briefly described as follows:

- data summary and display, with capability for statistical operations
- data display system for general purpose display work including transformations such as contour plots, gray level plots, streamline plots, and vector field display
- interactive retrieval and text editing systems for entering, editing and displaying textual data.

DESCRIPTION OF SYSTEMS AT OAK RIDGE NATIONAL LABORATORY

At ORNL the orientation to applications is particularly strong. While equipment support is available, as is programming system support, the development of planning applications is very visible. A considerable literature is available which describes the past projects and the role played by the laboratory in their development.

As a result of available publications, information regarding application status is easily discerned. Consequently it is also relatively easy to identify individual investigators to gain access to information regarding the status of on-going projects and of new directions in the application area.

Several laboratory programs should be identified as serving as an umbrella under which a number of the available applications and systems have been developed. The two most noteworthy documented at ORNL are:

- Regional Studies Program
- Regional Environmental Systems Analysis Program

The Regional Studies Program [42] (RSP) at ORNL is being conducted by several different groups and is directed to conducting assessments using available methodologies, and to devising new assessment methodologies. It can be considered a part of the framework erected for all laboratories as the Integrated Assessment Program. Under RSP, as presently structured, applications which have been developed include:

- coal utilization assessment
- coal reserves assessment
- power plant siting
- worker resource assessment
- employment-population forecasting
- regional model data system
- land use studies
- transport models

The Regional Environmental Systems Analysis Program [41] (RESA) at ORNL is directed primarily to devising an improved basis for assessing the impact of use of environmental and energy resources. The RESA program contains a number of the applications identified above as elements of the RSP program. The research program focused on a portion of East Tennessee and included models in four areas:

- socioeconomic analysis

- land use analysis
- natural systems analysis
- sociopolitical analysis

While the two study programs mentioned were not directly charged with development of user application systems, they did result in a group of applications systems which were used and continue to be available. Some of the frameworks devised for information systems continue to serve as the foundation for additional developments.

At ORNL facilities are available to make use of interactive computer graphics [45]. Such facilities include printer-plotter, mechanical plotters, video graphic display terminals, digitization equipment, and supporting graphics software.

ORNL Applications

Diverse application systems are available at ORNL ranging from siting of generation and transmission facilities to resource utilization studies. In some cases the studies which resulted in these applications were requested by DOE while in other cases they have been prepared in response to requests by state and regional agencies. In addition, funding for some of the projects has come from other Federal government agencies.

Generation Facility Site Selection

An extensive background has accumulated over the past years in site selection processes. At ORNL documented studies include the Maryland Power Plant Siting Project [43], the AEC-Maryland Siting Factors Study [72], and a companion study for a site on Kentucky Lake, Tennessee [61]. These studies all center on the use of cell-based models describing data in the region of interest.

The suitability of a given cell is measured by the criterion:

$$S_i = \frac{\sum (C_{vi} I_v) \quad v=1, N}{\sum (I_v) \quad v=1, N}$$

S_i is the suitability of cell i

v is the variable

N is the number of variables

C_{vi} is the compatibility index

I_v is the importance of variable i

This criterion can be applied in a regional evaluation to assess the relative merits of cells in a region for a specific technology. It may also be used to

evaluate individual sites for alternative technologies. Moreover, it may be used when prespecified siting related criteria are to be minimized as, e.g., adverse ecologic impact or adverse socioeconomic impact.

Such studies may be performed by reflecting revised compatibility values for alternative criteria. The variables which are considered in such models are listed in considerable detail in Reference [72]. They include water, transportation, geologic, demographic, and a variety of other factors.

Essential to the automation of such a site selection or comparison process is the availability of a digitized data base of cell based data. The data base is used to transform data values to compatibility values dependent upon a given mapping.

The available application systems at ORNL make use of thematic mapping to depict results of processing. Such thematic mapping may be generated on computer printer in a printer plotter stylized format, as in a more graphic fashion using a mechanical plotter. In either case cell values are depicted for either raw values of data, or for cell suitability values for a given set of compatibility and importance factors.

Transmission Line Routing

A methodology has been developed [60] at ORNL for assessing the aesthetic impact of a transmission line and reflecting this assessment into the comprehensive transmission line route selection process.

The method consists of quantification, on a cell-by-cell basis, of aesthetic variables and related weighting factors. The criterion used for evaluation is:

$$I_{ij} = (P_{ij})(L_{ij})(T_{ij}) \sum_{k=1,5} (A_{ijk}) \quad k = 1,5$$

I_{ij} is the impact at cell row i , column j

P_{ij} is the population factor of the cell ij

L_{ij} is the position factor of the cell ij

A_{ijk} is the esthetic variable evaluation for cell ij for variable k

The product $(P_{ij})(L_{ij})(T_{ij})$ serves as a weight for the cell.

A graphic plot of the results of an evaluation of a candidate region containing several alternative transmission routing is a byproduct of the evaluation. The plot is a thematic map showing levels of impact in accordance with preselected weights for the various factors contributing to the cell impact. Alternative plots are available for individual variable assessment and for cell weights.

The application should be considered one facet of the overall transmission route selection process. The other elements include:

- electrical configuration analysis
- structural systems evaluation
- cost optimization
- ecologic impact analysis
- political feasibility
- legal and regulatory constraints

Land Use Screening

The regional planning activities at ORNL have a strong orientation toward a comprehensive geocoded data base developed for a sixteen county area of East Tennessee including the city of Knoxville. Several regional planning applications make use of this comprehensive data base using evaluation criteria similar in form to that described earlier for the siting application.

The land use screening processes are built around a cell data model, cells which vary in size from forty to approximately ninety acres. Such screening processes may be utilized on a regional or subregional basis (not urban) for screening and quantifying land use for various purposes.

One such use is in the regional siting evaluation. The availability of a geocoded data base, the selection of importance values for variables, and compatibility mappings for cells are prerequisites. An application system [54] is described which allows the preparation of thematic maps depicting graphically the calculated cell suitability indices, as well as basic data values.

A general land use modelling program is also available [66] which quantifies over a region the linear expression:

$$LUS = \sum (W_{il})(I_i) \quad i = 1, L$$

LUS is the attractiveness value for land use category l

W_{il} is the index weight for the index i for land use category l

I_i is the index.

the indices include site preparation, availability of land, proximity to population, available utilities, accessibility to transportation and a variety of other variables. The results of use of this system is available on thematic maps produced by computer printer-plotter.

A related cell based system [59] is also available which allows cell based system modelling to be performed on a subregional basis to interface labor supply and demand with industrial land use allocation. This particular model requires projections of future economic development and availability of labor supply as well as labor market migrations.

Water Quantity Studies

A system is operation at ORNL for regional analysis of water availability. The Water Analysis System [55] (WAS) provides the data and the computational capability to perform regional water quantity assessments. The WAS system performs retrieval of historical daily stream flow measurements available from the United States Geological Survey, calculates occurrence frequencies, and allows simulation of water supply-demand systems to develop required reservoir sizes.

Two special studies carried out by ORNL staff made use of the WAS models. A study of the Ohio River Basin focussed on the impact of future energy facility development within the region on the available water supply. The study reflected energy demand requirements, and allocated anticipated available water to different facilities. The WAS system was used to calculate stream flows for the Ohio River and its major tributaries. A second study [44] was conducted with a view toward assessing the impact of the National Energy Plan on water quantities.

The WAS system and the studies identified above provide for some graphical depiction of results of processing. The studies, in particular provided for geographic depiction of water quantity demands associated with different alternative plans.

Transport Models

Two types of models are available for evaluation of emissions. One model [42] is used primarily to evaluate the atmospheric

distribution of emissions in the immediate vicinity of the emission source. The atmospheric transport model utilized at ORNL is based upon a plume model and studies have been performed which calculate sulfur dioxide deposition velocities.

A second type of model is used which performs a regional evaluation of emissions assuming numerous emission sources within a region of interest.

Coal Resource Studies

A cellular coal resource model [49] has been developed at ORNL for use in evaluating and calculating coal reserves in an area. The system provides graphic results in geographic map format of seam thickness and overburden. It also provides composite statistics of reserve tonnage. Input data to the system consists of a terrain model, coal seam location, drill hole data and identification of previously mined or excluded areas. Graphic results may be obtained by means of the computer printer and by mechanical or electrostatic plotters.

Miscellaneous Models

There is a group of models which are receiving attention at ORNL and for which graphic processes are utilized for depiction of results. The subject areas of these models include:

- a forest growth model reflecting the birth, growth, and death of various species of trees
- a data gathering process to provide information on various animal populations and how they may be affected by environmental changes such as transmission line rights-of-way

ORNL DATA BASES

Several data base support systems and data bases are available at ORNL relating to a variety of the applications being developed. Various techniques have been used to acquire data ranging from automatic digitization to manual transcription and data entry. In any case a significant investment has been made in devising programming support to initially accept, edit and transform data and to retain it in a conveniently processable form. The following describes some of the available data bases and support systems.

Oak Ridge Regional Modeling Information System (ORRMIS)

A geographically oriented information system [42], [45], has been developed at ORNL. The system provides a framework for data retention and for accessing data. The system provides for retention of data on a cell basis when a cell may be of grid form, a census district, a county or any spatially bounded area. The geographical data subsystem of ORRMIS performs digitization, editing, storage, and retrieval, transformation and analysis, and display of data.

It appears that ORRMIS in general is not a completely integrated comprehensive system, but instead provides a set of building blocks of subsystems which may be used individually or packaged with the aid of systems personnel. Consequently, as a result of this philosophy, various features of the system have been used in some of the applications described above.

The ORRMIS system, largely as a result of application orientation to grid systems, is strongly oriented to data bases structured on a grid cell basis. Data retained with the ORRMIS system data base includes:

- map data of physical characteristics
- land use data
- census data
- topographical data

The ORRMIS system also supports display of data. Display may be performed on a computer printer, mechanical plotter, or CRT video plotter. Such plots may be in the form of relief maps, contour maps, three dimensional surfaces, or graphs.

Data Base Variables

During interviews at ORNL the following component data files [42] were identified as available on a county basis for the southern region.

- seismic classification
- presence of rail lines
- energy demand
- barge channel depths
- population
- public lands
- geology
- water flow
- wildlife monitoring stations

These data are available primarily for plant siting evaluations.

Cell Based Data Index Techniques

The ORRMIS system described earlier provides for storage of cell-related data on a grid basis. There is available at ORNL a capability to construct indices indicating the characteristics of a cell as a composite of one or more of the raw data factors associated with the cell or adjacent cells. The index is a derived variable constructed from basic data in accordance with prespecified relationships. These relationships are generally weighted linear sums of spatially distributed data. As an example, an index for potential industrial park space could be devised from basic data such as transportation, utilities, size, zoning, cost, physical characteristics and location.

A computer program [69] CELNDX, calculates indices in accordance with user specifications of raw data variables and coefficients. The resulting indices may be stored in the ORRMIS data base.

Regional and Urban Studies Information Center - RUSTIC

At ORNL a Data Management and Analysis Group has responsibility for collection, evaluation, analysis and synthesizing data on social and economic aspects of energy supply and demand. The RUSTIC library [42] contains over 3000 reels of magnetic tape containing data and programs supporting such data.

Nominal Group Process Techniques

At ORNL the nominal group process technique (NGP) has had considerable development in helping to define variables affecting the power plant siting process [75]. The NGP technique, as performed at ORNL, identifies the variables to be utilized in locating new energy generation facilities and quantifies the importance of the individual variable. The technique makes use of group processes (engineers, ecologists, economists, natural resource specialists) in an interactive framework to identify the most important factors to be considered in selecting a site for a nuclear unit of specified size and type. The sequence of events incorporated in NGP includes:

- independent selection of factors
- group listing of factors
- discussion of factors
- independent voting on priority

ORNL Support Programming Systems

As in the case of data bases and data base support at ORNL, the available graphics support software at ORNL is less a comprehensive integrated system than a set of available services and loosely coupled subroutines. While extensive capability is available for many graphic interactive processes, it appears that they are generally used in a customized fashion for a given application. The following describes some of the most noteworthy of the available systems.

Polygon Mapping

The Polygon Mapping System produces thematic maps on a mechanical plotter or electrostatic plotter. The system allows user selection of the areas, specification of the shading to be assigned to specified areas in accordance with data values, annotation, and title information.

Cell Mapping

The Cell Mapping System produces thematic maps on a mechanical plotter or electrostatic plotter. The system allows printer maps, area calculations, and frequency distributions to be calculated.

Geographic Transformations

A set of geographical transformation programs [49] converts data from one structure to another. The conversions which are supported include grid-to-grid, grid-to-polygon, polygon-to-grid, point-to-point, point-to-grid, polygon-centroid-calculations, chains-to-polygons, and similar transformations. The transformations are especially useful in allowing alternative data representations.

Another set of routines [46] is available for coordinate conversion for data in different coordinate systems and map projections.

Perspective Surface Display System-PERSPX

The PERSPX system [49] prepares perspective and isometric displays of grid data. The program is available for use on a variety of devices including plotters and video display units.

Topographic Visibility Analysis - SEESIJ

The SEESIJ system [64] is used in assessing visibility of facilities. The system determines the objects which are visible from a given point, determines the distance to the nearest object in a collection, and finds the maximum effect (weight) of objects in the collection. The system is most useful in analysis of visual impact of transmission lines, cooling towers, stacks, and strip mines. The system is based upon a grid data base and is designed to be used with an ORRMIS data base.

Contour Mapping System

The contour mapping system [49] prepares contour maps using grid data. The map produced contains the contours and optionally shaded regions within contour lines. The contours may be plotted on county or state boundaries.

Digitization Systems

At ORNL present planning involves use of a semiautomated digitization system which includes an x-y digitized table with associated controls. This equipment is supported by a PDP-10 computer which accepts input from the operator along with x-y coordinates of the cursor. This process, while more effective than manual entry of data, is undergoing revision at ORNL so that immediate feedback of digitized data may be available for verification purposes.

An earlier system [45] was used to provide cell data from maps. The process made use of a flying-spot scanner and 35 mm film transparencies. The process was a fully automated one although a significant amount of validation and editing must be performed after the initial scanning is completed.

DESCRIPTION OF TECHNOLOGY

This section of the paper provides a capsule summary of the interactive computer graphics technology available to the laboratories. The primary motivation of this section is to present a summary of the types of systems available.

It should be recognized that the graphic systems depend upon the availability of computational resources. To perform extensive simulation and modelling, large scale computing systems are necessary. In general the computational needs of the applications are substantial. The resource requirements of the computing system are affected by the computational needs of the application and the need to support display preparation for graphic devices. It is difficult to specify the required computational resources except for the situation in which the uses of the computing system are identified. For this reason no mention is made here of the needs, in terms of computational resources, to support some of the applications described in this paper.

Today very little question is raised regarding technical feasibility in the application of interactive graphic systems. A variety of systems have proven effective within the past decade of use. Graphic system equipment has become more reliable and the program support required to use it effectively has become commonly available. It is a commonplace for larger commercial enterprises to have available in their data centers one or more types of graphic output devices as for example, a mechanical plotter or a microfiche recording device.

The marketplace offers a variety of field proven equipment. In many cases these systems are directly interfaced to available computer systems although in many cases such interfacing is the primary difficulty in utilization. An important step forward would be achieved if interface standards were adhered to by different suppliers. Such standardization is difficult to achieve in a time of rapid technology change during which new devices and technology improvements are occurring.

The classes of equipment available today, each from a variety of manufacturers include:

- mechanical pen plotters
- CRT video monitors
- electrostatic plotters
- film recorders
- large screen projectors
- digitization systems

The DUE laboratories have a variety of equipment available. Each facility visitor during the course of this study has available mechanical plotters and CRT video monitors, as well as unique customized equipment used in a research situation. In general the computers supporting such systems and the graphic output devices themselves are quite advanced, even when evaluated against comparable industrial and business systems. The most discernible shortcoming is one of systems everywhere and relates primarily to the inability to couple graphics input devices conveniently to such systems.

One can visualize graphic interactive systems as shown in Figure 2. Most commonly, graphic systems are used in a mode which excludes an extensive interaction and comprise only the blocks identified as computer, computer interface, display generator and the graphic output device. In a number of systems there is no electronic coupling between the computer system and the display generator. In such systems the development of graphic results is performed "off-line" and no interaction is obtained.

EQUIPMENT SYSTEMS

For purposes of classification of components of graphics systems reference can be made to the elements shown in Figure 2. User interface to graphic systems is generally through the graphic display, or output device, and by graphics input devices.

The types of graphics output devices include:

- mechanical plotter
- electrostatic plotter
- microfilm or microfiche recorder
- video monitor display units
- large screen projection systems

The types of graphics input devices include:

- editor keyboard
- cursor control by light pen, joy-stick or trackball
- digitizer table
- automatic digitization systems.

In any but the most rudimentary system the controlling element is an active processor (digital computer). At times the graphic system itself contains a small computer to support the display interface and to provide graphic display services. In many systems this unit of graphic input

and graphic output is designated an interactive graphics system and is in turn interfaced to a larger scale general purpose digital computer which supports the application calculations as well as display depiction.

To enhance the interactive aspect of graphics based applications, the presence of a large scale general purpose computer is virtually a necessity. The calculation capability inherent in the small scale computer which is a part of the graphics systems is generally minimal.

Graphic Output Devices

Mechanical Plotters

Mechanical plotters are of the drum or flatbed type and use pens to draw vectors and symbols. These mechanical devices are quite slow (10 to 20 inches per second) but do have accuracy up to the range of 0.001 inches. The size of the drum plotter is in the range of 30 to 36 inches while flatbed plotters may commonly be obtained in the size of 4 feet by 6 feet.

Electrostatic Plotter

More recent technology development has provided the electrostatic plotter with higher level capability for plotting. Electrostatic plotters generally function on the principle of a dot matrix with plotting densities up to 100 dots per inch in either horizontal or vertical direction. The speed of plotting for both alphanumeric and plotted data is quite high with paper speeds of 2 inches per second common.

Microfilm and Microfiche Recorder

Film and fiche recording may be performed for 35 mm film using one of several techniques for film recording. Such recording is extremely fast and can produce alphanumeric or graphic results. Within each film frame up to 10,000 x 10,000 points may be addressed thereby providing good resolution. Recording rates, in an alphanumeric mode, can approach the range of 20,000 lines per minute.

Video Monitor Display Unit

A variety of video monitor display units are available and offer a range of the following attributes:

- black/white or color
- alphanumeric, limited-graphic, or full vector
- storage tube or refresh tube
- display size, matrix size

These devices today offer the best opportunity for interactive graphics systems particularly when considering the close coupling with the graphic input devices. Depending upon the interface, and the nature of the display generator, displays can be brought up quickly on a unit, even when a substantial amount of calculation may also be required. Resolution may be to 0.01 inches.

Large Screen Projection Systems

Less use has been made, to date, of large screen projection systems than of video monitor display units. Large screen projection systems generally rely upon projection methods for information generally displayed on video units.

Graphic Input Devices

Editor keyboard

By far the most prevalent interactive input device is the editor keyboard. Such keyboards may be associated with a teletype-type unit, or a video display unit to control graphic depiction on a variety of graphic output devices.

Cursor Control

A variety of methods is available for control of a cursor on video monitor display units. They include a light pen, joy-stick or trackball, each of which facilitates cursor motion and in some cases also permits cursor selection. All three of these devices provide excellent flexibility for man-machine interaction.

Digitizer Tablet

A digitizer tablet is used in conjunction with a manual cursor to detect the position of the cursor and to transmit the coordinates to a computer. Generally the document being digitized may be quite large (up to 3 or 4 feet on a side) and resolution up to 0.001 inches may be obtained.

Automatic Digitization Equipment

Automatic (or semi-automatic) digitization equipment is used to convert image data (maps, photographs, drawings) to processable digital data. Such systems are quite costly and in many instances require significant interaction to assist in the digitization process. Alternatively after-the-fact editing of automatically acquired data may be performed.

Graphic Program Systems

Interface program support is commonly available today to permit users to prepare graphic output from the digital computer. The most rudimentary type of support basically provides a set of orders to drive the graphic device. Such programming is customarily available from suppliers of equipment.

A higher level of support is available from commercial enterprises specializing in program systems for graphics equipment. Frequently such systems will have the desired attributes of device independence. They also will relieve the user, interested in graphic results, of much of the basic functions, such as scaling of data for displays.

Reference has also been made to commercially available data base management systems and their general utility. The literature is heavily larded with references to such systems and consequently they are not discussed here.

Framework of Graphic Application Systems

Figure 1

Graphic Interactive System

Figure 2

TABLE I

ELECTRIC UTILITY INDUSTRY APPLICATIONS

Analytical Area / Basis of Application	Stochastic Models	Optimization Models	Network Simulation Models	Financial Models
Generation Planning	Loss of Load Probability Analysis	Economic Dispatch Commitment Optimum Generation Expansion Planning Maintenance Scheduling		Production Cost Financial Simulation of Expansion Plans
Transmission Planning	Reliability Analysis	Reactive Capacity Allocation Optimum Transmission Expansion Planning	Load Flow Short Circuit Transient Stability Optimum Real/Reactive Power Flow Analysis Transfer Limit Analysis Loss Formula Distribution Factor Analysis Switching Transients Analysis	Investment Cost Analysis
Energy Supply/ Demand Analysis	Load Forecasting Statistical Data Analysis			Load Component Data Economic Data Analysis Corporate Modelling

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APPENDIX
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APPENDIX

Reliability Criteria for System Design

The National Electric Reliability Council (NERC) was formed in 1968 with the stated purpose: "... further to augment the reliability and adequacy of bulk power supply in the electric utility systems of North America." It consists of nine Regional Reliability Councils and encompasses essentially all of the power systems of the United States and the Canadian systems in Ontario, British Columbia, Mani-

toba and New Brunswick. The nine councils, and the abbreviations commonly used for each, are shown in the figure below.

Each of the reliability councils has developed reliability criteria that are used for testing and evaluating simulated future systems designs. These criteria are given in the following pages as a reference and supporting document to the technical papers of this publication.

REFERENCE: "National Electric Reliability Council", 6th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, July 1978.

*Symposium on Reliability Criteria
For System Dynamic Performance*

ECAR RELIABILITY CRITERIA

The East Central Area Reliability Coordination Agreement provides for the establishment of principles and procedures regarding matters affecting the reliability of bulk power supply within ECAR. It recognizes that the evaluation and simulated testing of systems' performance are essential elements in assuring reliability. In accordance with the provisions of the Agreement, the ECAR members have formulated a set of reliability criteria to be used as the basis for such evaluation and simulated testing.

This document presents the reliability criteria adopted by ECAR for the above purposes. It represents the combined judgement of the ECAR members and includes, in addition to a listing of reliability criteria, a brief description of the underlying principles that served as the basis for their development.

Basis for the Selection of Reliability Criteria

In the process of formulating the reliability criteria presented in this document, the ECAR members recognized:

- I. The need to plan, build, and operate bulk power supply systems that would be immune to uncontrolled, widespread, cascading power interruptions even under the most adverse credible conditions and the fact that it is technically feasible to achieve this objective.
- II. The importance of providing a high degree of reliability for local power supply but the impossibility of providing 100% reliability to every customer or every local area.
- III. The importance of considering local conditions and requirements in setting up criteria for the reliability of local power supply and the need, therefore, to view reliability in local areas as the responsibility of the individual ECAR members.

In addition to the above, the ECAR members recognized the impossibility of anticipating, and testing for, all possible contingencies that could occur on either the present or future interconnected bulk power supply network of the ECAR systems. ECAR believes, therefore, that the reliability criteria should serve primarily as a means to measure the strength of the systems to withstand the entire spectrum of contingencies that can and that cannot be readily visualized, rather than comprise a detailed listing of probable disturbances. In view of this, the selection of reliability criteria is based not on whether the specific contingency for which the system is being tested is in itself probable or even possible, but rather on whether it constitutes an effective and practical means to stress the systems and thus to test their ability to avoid uncontrolled, area-wide power interruptions even under the most adverse credible conditions.

The ECAR members believe that the most effective safeguard against a possible occurrence of uncontrolled, area-wide power interruptions on a large bulk power supply system is strict adherence to the basic principles of bulk power supply planning, with full recognition of anticipated operating requirements when designing the system, combined with sound subsequent operation within the design capabilities. A listing of these basic principles is as follows:

- I. Maintenance of a balanced relationship among power system elements, in terms of size of load, size of generating units and plants, strength of interconnections, and the amount of power being carried on any single transmission channel.
- II. The adherence to this principle implies:
 - A. avoiding excessive concentrations of generating capacity in one unit, at one location, or in one area;
 - B. avoiding excessive concentrations of power being carried on any single transmission circuit, tower line, or right-of-way, as well as through any one transmission station; and
 - C. provision of interconnection capability that is commensurate with the size of the system load and with the size of generating units and plants.
- III. Provision of transmission capability within the bulk power supply network well in excess of that required for normal transportation of power from generating sources to load centers, so as to maintain a high degree of flexibility in operation and in meeting a wide range of contingencies.

- IV. Utilization of switching arrangements that would permit effective maintenance of equipment without excessive risk to the interconnected network of ECAR systems.
- V. Utilization of adequate switching arrangements and associated relay schemes that do not involve unduly complicated controls and that do not limit the capability of a transmission channel to the extent of causing excessive risk to the interconnected network of ECAR systems.
- VI. Operation of the interconnected systems of ECAR members so that power interchanges within ECAR and with systems outside ECAR remain within the systems' design capabilities.

Reliability Criteria for Simulated Testing

The simulated testing is to be directed toward assuring that the ECAR bulk power supply network, or any major part thereof, will not suffer a cascading area-wide break-up and collapse under contingencies such as those enumerated below.

- I. Sudden outage of any transmission circuit at a time when a combination of any three generating units is out of service.
- II. Sudden outage of any double-circuit transmission tower line at a time when a combination of any two generating units is out of service.
- III. Sudden outage of any generating unit at a time when any two other generating units are out of service.
- IV. Sudden outage of all generating capacity at any generating plant.
- V. Sudden dropping of a large load or a major load center.
- VI. Sudden outage of all transmission lines on the same right-of-way.
- VII. Sudden outage of any transmission station, including all generating capacity associated with such a station.
- VIII. Sudden outage of any tower line at the time when any other one circuit is out of service.

In carrying out simulated testing in accordance with the above criteria, careful attention is to be given to the following:

- I. Steady-state, dynamic and transient stability considerations, including three-phase faults at the most critical locations.
- II. The effect of slow fault clearing as a consequence of improper relay operation or failure of a circuit breaker to open.
- III. Possible occurrence of the above contingencies not only on the interconnected ECAR network, but also on the network of the power systems connected to ECAR.
- IV. The entire range of operating modes for the interconnected system being tested, including the anticipated range of scheduled power deliveries or receipts.

The simulated testing is to take into account the projected conditions on the systems adjacent to ECAR, making the greatest possible use of data and study results obtained from inter-regional studies with non-ECAR systems.

The criteria for evaluation and simulated testing of the ECAR bulk power supply system have been prepared to meet present and anticipated future conditions as they are visualized today. Since conditions may change with time, the criteria will be periodically reviewed to assure their continued applicability.

ERCOT RELIABILITY CRITERIA

- I. Sufficient generating capacity will be provided, as nearly as practicable, to ensure a reserve of at least 15 percent of the forecasted maximum hour demand of the Interconnected System.
- II. Projected Interconnected System planning will include simulated testing to ensure that the system will not experience cascading breakup and collapse initiated by the occurrence of contingencies such as:
 - A. Loss of all generating capacity at any generating station.
 - B. Loss of any two generating units.
 - C. Outage of any circuit or generating unit during scheduled maintenance on any other transmission line or generating unit.

- D. Outage of any single or double circuit transmission line, generating unit, transformer, or bus.
- E. Simultaneous outage of overhead transmission lines parallel to each other for a substantial distance having a spacing between circuits of less than the height of the structures.
- F. Any fault cleared by normal operation of backup relays.
- G. Loss of any large load or concentrated load area.

MAAC RELIABILITY CRITERIA

Principles

The bulk electric supply system shall be planned and constructed in such manner that it can be operated so the more probable contingencies can be sustained with no loss of load. Less-probable contingencies will be examined to determine their effect on system performance. These standards apply only to those facilities which affect reliability of the MAAC system and not to facilities affecting the reliability of supply only to local system loads. Automatic load relief shall be provided to minimize the probability of the total shutdown of an area which becomes isolated by multiple contingencies, thereby facilitating rapid restoration of the interconnected systems.

Reliability Standards

- I. Installed generating capacity requirements: Sufficient megawatt generating capacity shall be installed to insure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered in the calculation of the probability are the characteristics of the loads, the probability of error in load forecast, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, limited energy capacity, the effects of connections to other pools, and network transfer capabilities within the MAAC systems.
- II. Transmission requirements: The bulk transmission system shall be developed so that it can be operated at all load levels to meet the following unscheduled contingencies without instability, cascading or interruption of load:
 - A. The loss of any single generating unit, transmission line, transformer, or bus in addition to normal scheduled outages of bulk electric supply system facilities without exceeding the applicable emergency rating of any facility. After the outage, the system must be capable of readjustment so that all equipment (on the MAAC and neighboring systems) will be loaded within normal ratings.
 - B. After occurrence of the outage and the readjustment of the system specified in (A), the subsequent outage of any remaining generator or line without exceeding the short time emergency rating of any facility. After this outage, the system must be capable of readjustment so that all remaining equipment will be loaded within applicable emergency ratings for the probable duration of the outage.
 - C. The loss of any double circuit line or the combination of facilities resulting from a line fault and a stuck breaker in addition to normal scheduled generator outages without exceeding the short time emergency rating of any facility. After the outage, the system must be capable of readjustment so that all equipment will be loaded within applicable emergency ratings for the probable duration of the outage.

In determining the bulk transmission requirements, recognition shall be given to the occurrence of similar contingencies in neighboring systems and their effect on the MAAC system.
- III. General requirements: Sufficient megawatt capacity with adequate controls shall be installed in each system to supply the reactive load and loss requirements in order to maintain acceptable emergency transmission voltage profiles during all the above contingencies.

Installation of generation and transmission facilities shall be coordinated to insure that in each year for each member system the probability of occurrence of load exceeding the available capacity resources shall not be greater, on the average, than one day in ten years. Available capacity resources consist of the generating capability available internal to the member system and the capacity that can be transmitted into the member system. (See Network transfer capability)

- IV. Stability requirements: The stability of the system shall be maintained without loss of load during and after the following types of faults occurring at the most critical location at all load levels.
 - A. A three-phase fault with normal clearing time.
 - B. Single phase-to-ground fault with a stuck breaker or other cause for delayed clearing.
- V. Tests for ability of MAAC system to withstand abnormal disturbances: The MAAC group recognizes that it is impossible to anticipate or test for all the contingencies that can occur on the present and future MAAC system. These tests, therefore, serve primarily as a means to measure the ability of the system to withstand less probable contingencies, some of which may not be readily apparent. These tests are prescribed not on the basis of a high level of probability, but rather as a practical means to study the system for its ability to withstand disturbances beyond those which can reasonably be expected. The MAAC system, therefore, will be tested to determine the effect of various types of contingencies on system performance. Examples of less probable contingencies to be studied are:
 - A. Sudden loss of the entire generating capability of any station for any reason.
 - B. The outage of the most critical transmission line on any one of the interconnected systems as the result of a three-phase fault immediately following (i.e., before readjustment) the tripping of another critical line on the same or on an adjacent system.
 - C. The sudden loss of all lines of one voltage emanating from a substation.
 - D. The sudden loss of all lines on a single right-of-way.
 - E. The sudden dropping of a large load or a major load center.
 - F. The occurrence of a multi-phase fault with delayed clearing.
- VI. Relaying and protective devices: Independent devices shall be installed to the extent necessary to provide backup for the primary protective devices and components so as to limit equipment damage, to limit the shock to the system and to speed restoration of service. Relaying installed shall not restrict the normal or the necessary realizable network transfer capabilities of the system. Underfrequency relays shall be installed to provide additional insurance against widespread system disturbances. They shall not be used to satisfy the contingencies listed under the installed generating capacity requirements and the Transmission requirements sections.
- VII. Network transfer capability: The amounts of power planned to be interchanged between areas within MAAC and between MAAC and neighboring pools shall be such that applicable ratings and stability, voltage and relay limitations are not exceeded.
 - A. Extended period transfer: The maximum amount of capacity planned to be delivered from one area to another for economy interchange in normal day-to-day operations shall be limited as follows:
 - 1. With all transmission facilities in service and normal generator maintenance scheduling, all system components shall be within normal loading limits.
 - 2. With the outage of any single facility, the provisions of the Transmission requirements (A) section shall apply.
 - B. Capacity emergency transfer: The maximum amount of capacity planned to be transferred from one area to another for capacity shortages shall be limited as follows:
 - 1. With all transmission facilities in service and nor-

mal generator maintenance schedules, the loadings of all system components shall be within applicable emergency ratings and stability limits and no excessive voltage drops shall occur.

2. The interconnected systems shall then be able to absorb the initial power swing resulting from the sudden loss of any one transmission line or generating unit.
3. After the initial swing period, the loadings of all system components shall be within short time emergency ratings and acceptable voltage limits.

MAIN RELIABILITY CRITERIA

The primary purpose of MAIN is to promote maximum coordination of planning, construction and utilization of generation and transmission facilities on a regional basis to provide reliability and adequacy of electric bulk power supply in the MAIN area. Recognizing that the simulated testing of existing and planned bulk power systems is essential to measure reliability and adequacy, the testing methods and criteria described in this Appendix have been adopted by MAIN.

This Appendix presents the characteristics of a well planned bulk power transmission system, and describes the basis for model testing along with a list of the reliability and adequacy tests which will be used to evaluate the performance of the MAIN bulk power regional transmission system.

- I. Characteristics of a well planned system: The following basic characteristics are considered essential to a well planned system and would be expected to provide (1) an effective safeguard against the occurrence of an uncontrolled area-wide power interruption and (2) adequate transfer capabilities.
 - A. Maintenance of a balanced relationship among power system elements, in terms of size of load, size of generating units and plants, strength of interconnections and the concentration of power at any point on the transmission system. Adherence to this principle implies:
 1. Avoiding excessive concentration of generating capacity in one unit, at one location, or in one area.
 2. Avoiding excessive concentration of power being carried on any single transmission circuit, tower line, or right-of-way, as well as through any one transmission station.
 - B. Adequate transmission and interconnection capability to provide for intraregional, interregional, and transregional power flows under normal conditions, and to meet a wide range of contingencies.
 - C. Utilization of switching arrangements that would permit effective maintenance of equipment without excessive risk to the system.
 - D. Utilization of adequate switching arrangements and associated relay schemes that do not limit the capability of a transmission channel to the extent of causing excessive risk to the system.
 - E. Operation of the interconnected systems of MAIN members so that power interchanges within MAIN and with systems outside remain within design capabilities.
- II. General guide for testing models of the bulk power transmission system:

In planning and operating a bulk power transmission system to have a high degree of reliability, conditions should be avoided which could cause an uncontrolled break-up and collapse of the interconnected system even for extremely improbable but credible contingencies. Providing 100% reliability is, of course, impossible, but it is possible to build an interconnected bulk power system in which uncontrolled widespread interruptions would be very unlikely even during improbable disturbances.

Also, it is impossible to anticipate and test for all combinations of contingencies that could occur on an interconnected network. Therefore, the reliability and adequacy testing criteria should be such as to thoroughly search out the maximum credible contingencies for examination with

good assurance that the many possible contingencies not studied are less severe.

A two-part testing program has been formulated which provides an indication of the system's strength (1) to withstand an extreme disturbance without uncontrolled cascade tripping (Extreme Disturbance Tests) and (2) to supply the system load during possible generator and/or line outage conditions without exceeding the interconnected system's thermal, voltage or stability limitations (Interchange Capability Tests). The latter implies adequate transmission Interchange Capability between systems within MAIN and between MAIN and other regions.

III. Reliability and adequacy criteria for simulated testing and system evaluation

A. Extreme disturbance testing: The generation and transmission system shall be adequate to withstand the most severe of the following set of contingencies without resulting in an uncontrolled widespread tripping of lines and/or generators with resulting loss of load over a large area:

1. Sudden outage of any tower line at the time when any other one circuit is out of service.
2. Sudden outage of any transmission circuit at a time when a combination of any three generating units is out of service.
3. Sudden outage of any double-circuit transmission tower line at a time when a combination of any two generating units is out of service.
4. Sudden outage of all transmission lines on the same right-of-way.
5. Sudden outage of any generating unit at a time when any two other generating units are out of service.
6. Sudden outage of all generating capacity at any generating plant.
7. Sudden outage of any transmission station, including all generating capacity associated with such a station.
8. Sudden dropping of a large load or a major load center.
9. Any other credible contingency which might lead to system cascading.

The studies conducted to test the effect of the above contingencies should give due consideration to the following:

- a. Steady-state, dynamic and transient stability consideration, including three-phase faults at the most critical locations.
- b. The effect of slow fault clearing as a consequence of improper relay operation or failure of a circuit breaker to open.
- c. Possible occurrence of the above contingencies not only on the interconnected MAIN network, but also on the network of adjacent power systems, where a major contingency might involve MAIN or portions thereof in a cascading incident.
- d. Expected normal and emergency power flow conditions.

B. Interchange capability testing: The transmission system shall also be designed to insure adequate interchange capability of the MAIN system during both normal and emergency conditions. Three operating modes are to be used in testing MAIN interconnection capabilities, as defined in the Definitions of Transfer Capabilities below. These can be summarized as follows:

Emergency Transfer Capability: All lines in service. Can withstand loss of one key facility.

Extended Period Transfer Capability: One key facility out of service. Can withstand loss of second key facility.

Installed Interconnection Capability: All lines in service. Does not consider loss of a key facility.

Generally, the "Emergency Transfer Capability" will be used to determine the safe operating levels for intraregional, interregional, and transregional power flow, and for reporting purposes.

Transmission interchange capability based on the "Extended Period Transfer Capability" is pertinent in considering plans to transfer power for periods of weeks or months. It is recognized that the probability of double contingencies at times of heavy system load and reduced system generation reserve is relatively low; however, these data are useful for disclosing possible weaknesses in the design of the transmission system and therefore may be considered in planning and operating the system.

It is also recognized that the large variation in system loadings and the many combinations of double outages make it impossible, in a generalized study, to examine all the conditions that could be encountered, in determining the "Extended Period Transfer Capability". It is recommended that specific operating studies be made when large quantities of power are to be transferred for periods of weeks or months, or when maintenance will occur on a critical element for extensive periods and the outage of a second critical element might impair reliability or cause cascading.

C. Interchange capability criteria:

The "Emergency Transfer Capability" of the transmission network into each of MAIN groups should be at least equal to the emergency assistance level required to maintain a reasonable generation reserve margin. Studies of reserve requirements based on MAIN Guide No. 6 (available from NERC) are useful in determining the required emergency assistance.

The "Extended Period Transfer Capability" of the transmission network into each of MAIN groups should be at least sufficient to provide for all planned firm and diversity scheduled interchanges. This criteria generally is used in long range studies where uncertainties in network developments exist to a greater degree than for short term operating studies.

Definitions for Transfer Capabilities

- I. Emergency Transfer Capability: This is the total amount of power (above the net contracted purchases and sales) which can be scheduled, and with an assurance of adequate system reliability, for interregional or multiregional transfers over the transmission network for periods up to several days, based on the most limiting of the following:
 - A. All transmission loadings initially within long time ratings and all voltages initially within acceptable limits.
 - B. The bulk power system capable of absorbing the initial power swings and remaining stable upon the loss of any single transmission circuit, transformer, bus section, or generating unit.
 - C. All transmission loadings within their respective short-time emergency ratings and voltages within emergency limits after the initial power swings following the disturbance but before system adjustments are made. (In the event of a permanent outage of a facility, transfer schedules may need to be revised).
- II. Extended Period Transfer Capability: This definition establishes the maximum amount of power which could be transferred for periods of weeks or months. It is determined in accordance with the following conditions:
 - A. All transmission loadings and voltages should be within normal ratings and limits.
 - B. With the loss of any single facility (transmission circuit, generating unit, transformer, or bus section), the system should be able to absorb the initial power swings and remain stable; all post-swing transmission loadings should be within their respective long-time ratings and voltages should be within acceptable limits.
 - C. With the overlapping outage* of any two facilities (transmission circuit, generating unit, transformer, or bus section) the system should be able to absorb the initial power swings from the loss of the second facility and remain stable; all post-swing transmission loadings should be within their respective short-time emergency ratings before any system adjustments can be

- III. Installed Interconnection Capability: This is the transfer capability of a transmission system with all facilities in service and does not recognize the effect of a generator or transmission outage on the system. It provides a general guide to the strength of the interconnected system being studied. It is also the first step in the determination of transfer capabilities in accordance with the NERC Emergency Transfer Capability definition.

*System adjustments may be made following the first outage of the overlapping outages in accordance with the particular region's operating procedures.

- Notes:
1. Generally, outages to test the Emergency Transfer Capability and the Extended Period Transfer Capability will be limited to the loss of transmission circuits, generating units, and transformers.
 2. The "long-time emergency ratings" generally will be the normal rating of the facility.

NPCC RELIABILITY CRITERIA

Introduction

The purpose of the Northeast Power Coordinating Council is to improve the reliability and efficiency of the interconnected power systems of its members through improved coordination in system design and operating procedures.

One of the steps in reaching this objective is the development of criteria that will be used in the design and operation of the major interconnected power systems. Definitions of several terms used in the following paragraphs are listed in the List of Definitions.

It is recognized that more rigid criteria will be applied in some segments of the Council area because of local considerations. It is also recognized that the basic criteria are not necessarily applicable to those elements of the individual members' systems that are not a major part of the interconnected transmission network.

The transmission criteria are applicable either to the areas (New Brunswick, New England, New York or Ontario) or to the entire Council interconnection in its relations with neighboring "pools".

An interconnected power system should be designed and operated at a level of reliability such that the loss of a major portion of the system would not result from reasonably foreseeable contingencies. In determining this reliability, it would be desirable to give consideration to all combinations of contingencies occurring more frequently than once in some stipulated number of years. However, sufficient data and techniques are not available at the present time to define all the contingencies that could occur or to assess and rank their probability of occurrence. Therefore, it is proposed that the interconnected power systems be designed and operated to meet certain specific contingencies. Loss of small portions of the system (such as radial portions) may be tolerated, provided that these do not jeopardize the integrity of the over-all interconnected power systems.

The following criteria for design and operation of interconnected power systems define area generation and transmission requirements. In addition, criteria for determining inter-area transmission transfer capabilities are defined.

Two categories of transmission transfer capabilities are to be considered: normal and emergency. Normal conditions are to be assumed unless an emergency, as defined by Item 2 in the "List of Definitions", exists.

Design studies will assume applicable contractual transfers and the most severe expected load and generation conditions. Operating transfer capability studies will be based on the particular load and generation pattern expected to exist for the period under study. All reclosing facilities will be assumed in service unless it is known that such facilities have been rendered inoperative.

Generating Capacity

Generating capacity will be installed and located in such a manner that after the due allowance for required maintenance and expected forced outages, each area's generating supply will equal or exceed area load at least 99.9615 percent of the time. This is equivalent to a "loss-of-load probability of one day in ten years".

Area Transmission Requirements

The power system should be designed with sufficient transmission capacity to serve area loads under the conditions noted below. The power system should also be operated in such a manner that the design objectives are fulfilled.

I. Stability Condition

Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in A, B, C, D, and E below. Also, the system must be adequate for testing of the outaged element as described in "A" through "E" by manual reclosing after the outage and before adjusting any generation. These requirements will also apply after any critical generator unit, transmission circuit, or transformer has already been lost, assuming that the area generation and power flows are adjusted between outages by use of Five-Minute Reserve.

- A. A permanent three phase fault on any generator, transmission circuit, transformer or bus section, cleared in normal time, with due regard to reclosing facilities.
- B. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.
- C. A permanent phase to ground fault on any generator, transmission circuit, transformer, or bus section with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.
- D. Loss of any element without a fault.
- E. A permanent phase to ground fault on a circuit breaker, cleared in normal time, and with due regard to reclosing facilities.

II. Steady State Conditions

- A. Voltages, line and equipment loadings shall be within normal limits for pre-disturbance conditions.
- B. Voltages, line and equipment loadings shall be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in I.

Transmission Capabilities

Transfers of power from one area to another, as well as within areas, should be considered in the design of inter-area transmission and internal area facilities.

Operating capabilities shall be adhered to for normal transfers and transfers during emergencies. These capabilities will be based on the facilities in service at the time of the transfers. In determining the emergency transfer capabilities, it is assumed that a less conservative margin is justified.

Transmission transfer capabilities shall be determined under the following conditions:

I. Normal Transfers

- A. Stability conditions: Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in 1, 2, 3, 4, and 5 below. Also, the system must be adequate for testing of the outaged element as described in "1" through "5" by manual reclosing after the outage and before adjusting any generation.
 1. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time, with due regard to reclosing facilities.
 2. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.
 3. A permanent phase to ground fault on any generator, transmission circuit, transformer, or bus section with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or

signal channel malfunction.

4. Loss of any element without a fault.
 5. A permanent phase to ground fault on a circuit breaker, cleared in normal time, and with due regard to reclosing facilities.
- B. Steady State Conditions**
1. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within normal limits.
 2. Voltages, line and equipment loadings shall be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in A.

II. Emergency Transfers

- A. Stability Conditions: Stability of the interconnected systems shall be maintained during and after the most severe conditions in "1" and "2" below. System conditions may be adjusted before the outaged element as described in "1" and "2" below is tested.
 1. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time and with due regard to reclosing facilities.
 2. Loss of any element without a fault.
- B. Steady State Conditions
 1. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within applicable emergency limits.
 2. Voltages, line and equipment loadings shall be within applicable emergency limits following the disturbance in A.

Possible but Improbable Contingencies

Studies will be conducted to determine the effect of the following contingencies on system performance and plans will be developed to minimize the spread of any interruption that might result.

- I. Loss of the entire capability of a generating station.
- II. Loss of all lines emanating from a generating station, switching station or substation.
- III. Loss of all transmission circuits on a common right-of-way.
- IV. Permanent three phase fault on any generator, transmission circuit, transformer, or bus section, with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.
- V. The sudden dropping of a large load or a major load center.
- VI. The effect of severe power swings arising from disturbances outside the Council's interconnected systems.

List of Definitions

Area: An area is defined as either New Brunswick, New England, New York or Ontario.

Emergency: An emergency is assumed to exist in an area if firm load may have to be dropped because sufficient power is unavailable in that area. Emergency transfers are applicable under such conditions.

Applicable Emergency Limits: These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitation, etc.

Short time emergency limits are those which can be utilized for at least five minutes.

The limiting condition for voltages should recognize that voltages at key locations should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the interconnected systems.

The limiting condition for equipment loadings should be such that cascading will not occur due to operation of protective devices on the failure of facilities.

Five-Minute Reserve: Five-Minute Reserve is that portion of unused generating capacity which is synchronized to the system, and is fully available within five minutes, plus that portion of capacity available in shut down generating units, in pumped hydro units and by curtailing interruptible loads which is fully available

within five minutes.

"With Due Regard to Reclosing Facilities": is intended to mean that recognition will be given to the type of reclosing: i.e., manual or automatic, and the kind of protective schemes insofar as time is concerned.

Element: An element is defined as a generator, transmission circuit, transformer, circuit breaker or bus section.

MARCA RELIABILITY CRITERIA

The standards of the Mid-Continent Area Reliability Coordination Agreement (MARCA) described herein are recognized by the Council as essential to assure that continued development of the MARCA system will be carried out in a manner which will maintain a high degree of bulk power supply reliability. Bulk power supply of a system is defined as the generating capacity and the portion of the transmission system operated at 115 kv or higher, which has a significant influence on operation of contiguous systems. The intent of the Council is that bulk power facilities of the Parties shall comply with these standards. If a Party believes that variations from these standards are appropriate for a specific facility, it shall be the responsibility of that Party to satisfy the Council that the area reliability will not be impaired.

System Design Standards

I. Generating Capacity Requirements

Each Party's installed generating capacity (net capability) for any month, adjusted for power purchases and sales, shall be not less than its maximum integrated hour demand for that month plus a reserve of 12% (10% for a hydro system) of such demand for the twelve month period ending with the current month. The Council shall periodically review this reserve criterion by having reserve requirement studies conducted. These studies shall consider the effects of the probability of forced outages of generating units, deviations from load forecast, scheduled maintenance of generating units, power exchange arrangements with non-member systems, and transfer capabilities.

II. Bulk Power Transmission System Requirements

A. Probable Disturbances: In the development of the MARCA bulk power transmission system a level of reliability is intended to be maintained such that contingencies having a reasonable probability of occurrence will not result in service interruptions to a major portion of the system. With the MARCA system normal or with any critical generator, line, or transformer already out of service and operations adjusted to restore system security, the system shall be capable of withstanding the following contingencies without interruption of load due to instability or cascading:

1. Loss of any line, generator, transformer or single bus section.
2. A permanent three-phase fault on any element including automatic reclosing if used.
3. A permanent phase-to-ground fault on both circuits of a double circuit line with automatic reclosing if used.
4. A permanent phase-to-ground fault on any element with delayed clearing due to a circuit breaker not operating.

Voltages and facility loadings shall be within applicable emergency limits following the above contingencies without further adjustment of generation.

In determining the bulk power transmission requirements, consideration shall be given to the occurrence of similar contingencies in neighboring systems and the effect on the MARCA system.

B. Extreme Disturbances: It is impossible to anticipate or test for all disturbances that can occur on the present and future bulk power supply system. Simulating extreme disturbances, however, can serve as a means to measure the ability of the system to withstand less probable contingencies, some of which may not be readily apparent. These tests are prescribed only as a practical means to study the system for its ability to withstand disturbances more severe than those defined in Section A. Tests by simulation will be made to determine the effect of the following extreme disturbances on the

performance of the bulk power supply system. System development shall be designed to minimize the spread of any interruption that might result from:

1. The sudden loss of the entire capability of a generating station.
2. The sudden loss of all lines from a generating station, switching station or substation by three-phase faults.
3. The sudden loss of all circuits on a common right-of-way by a permanent three-phase fault on each circuit.
4. The sudden dropping of a large load.

III. Relaying and Protective Devices

Independent devices shall be installed to the extent necessary to provide backup for the primary protective device and components to limit equipment damage, to limit shock to the system and to speed restoration of service.

Relaying shall not restrict the power transfer capability that may reasonably be expected to exist between any two points of the system.

IV. Design Review Procedures

The procedures for review and evaluation of each Party's planning for generation and transmission facilities and other matters relevant to the reliability of bulk power supply are:

A. Each Party shall submit, by February 1st of each year, to the Design Review Committee its plans for generation and bulk power transmission for the next six year period. The plans shall be submitted in summary form including a map and a one line electrical diagram of the proposed facilities. Any changes to a Party's plan shall be submitted promptly to the Design Review Committee for review and evaluation.

B. Each Party shall submit to the Design Review Committee copies of study reports supporting the plans and relating to reliability, such as load flow and stability studies. These studies shall recognize the System Design Standards.

C. Each Party shall submit to the Design Review Committee load and capability data for a period of ten years. This should include the method of forecasting load.

After reviewing and evaluating each Party's planning with respect to the System Design Standards, the Design Review Committee shall decide whether or not additional studies should be performed in order to determine overall reliability for the area. A report on the reliability of the MARCA system for the ensuing six years shall be made to the Council no later than six months after receipt of the plans of the Parties.

SERC RELIABILITY CRITERIA

The purpose of SERC "... is to augment further the reliability of bulk power supply in the areas served by the member systems." This can be best accomplished by promoting maximum coordination of planning, construction and utilization of generation and transmission facilities involved in interconnected operations.

To assist in achieving these objectives, the member organizations of SERC recognize the need for common criteria to be used in the planning of their systems for adequate and reliable bulk power supply.

Local Area Criteria

It is recognized that the reliability of power supply in local areas is the responsibility of the individual SERC members and that each system has internal criteria relating to the more common contingencies. It is further recognized that there are severe contingencies which are credible but of a low probability of occurrence, which may result in conditions such as islanding and/or loss of load. Such conditions are considered acceptable as long as they are controlled so as to limit the adverse impact of the disturbance and so as to leave the system or systems in such condition as to permit rapid load restoration and/or reconnection.

SERC Regional Criteria

The objective of the regional criteria is to assure that the SERC bulk power systems are planned so that cascading outages will not result from any foreseeable contingencies. These criteria are, therefore, directed only at preventing cascading.

Cascading is defined as the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in an uncontrolled, widespread collapse of system power which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Each of the SERC member systems will be planned to avoid cascading upon the occurrence of the following contingencies:

- I. Loss of Generation
 - A. Sudden loss of entire generating capability in any one plant.
- II. Loss of Load
 - A. Sudden loss of a large load or major load center.
- III. Loss of Transmission
 - A. The outage of the most critical transmission line caused by a three-phase fault during the outage of any other critical transmission line.
 - B. Sudden loss of all lines on a common right-of-way.
 - C. Sudden loss of a substation (limited to a single voltage level within the substation plus transformation from that voltage level), including any generating capacity connected thereto.
 - D. Delayed clearing of a three-phase fault at any point on the system due to failure of a breaker to open.

SPP RELIABILITY CRITERIA

Introduction

Reliable operation of the interconnected bulk power systems of the Southwest Power Pool requires that all systems observe and subscribe to certain minimum planning criteria.

The planning criteria set forth herein are intended to serve as guidelines for developing more specific and definitive criteria by each system or control area.

General Planning Criteria

Those criteria that are general in nature and necessary in the normal planning of the interconnected bulk power systems are set forth in this section.

- I. In general, the generation and transmission systems of the Southwest Power Pool shall be planned and constructed so that the more probable contingencies as set forth in Subsections I and II of the Principals of Transmission Planning Section will not result in major or long time interruption of load. Furthermore, one of these more probable contingencies should not cause the emergency rating of any equipment to be exceeded and the system shall be capable of being readjusted within a few minutes after the occurrence so that all equipment will be operating within its normal rating. The less probable contingencies as set forth in Subsection III of The Principals of Transmission Planning Section may result in major interruption of load. However, this situation should be controlled so as not to result in cascading of interruptions.
- II. In general, the bulk power facilities will be studied on a Group basis. An individual company can petition the Southwest Power Pool Coordination Committee to be reassigned from one Group to another Group or to be included in more than one Group as required to meet its needs.
- III. Sufficient reactive capacity shall be available within the Southwest Power Pool system at the appropriate places to maintain system voltage (when the more probable contingencies occur) within 5% of normal at the major busses of the transmission system.
- IV. To alleviate those unlikely situations where multiple contingencies result in a portion of the Southwest Power Pool system becoming isolated with a resultant deficiency in generation, underfrequency relays shall be installed to selectively remove load. Amount of load to be removed and frequency steps shall be as indicated in the Southwest Power Pool

Operating Criteria. When underfrequency relay action and all other actions fail to remedy the situation and the possibility exists of generators tripping or being damaged due to low frequency, generators shall be disconnected from the system, either manually or by relay action. These generators shall be disconnected from the system preferably with enough local load remaining to stabilize their operation so that service can be restored rapidly.

- V. In general, underfrequency relays should not be installed on transmission interconnections; however, in cases where installation is considered necessary and has been mutually agreed upon between the parties involved, the relays shall be non-directional.

Principles of Generation Planning

Those criteria that are applicable to the general aspects of planning generating capacity additions and certain design features affecting reliability are set forth in this section.

- I. Generation Capacity

Planning of capacity additions must provide that the total generating capacity available to each Group in the Southwest Power Pool system shall be such that the capacity available shall exceed the predicted annual peak load obligation by a margin of 15%, or as an alternative, a probability study made so as to insure that the probability of load exceeding capacity available to such Group shall not be greater than one occurrence in ten years provided that in no case shall the reserve be less than the peak load obligation by 12%.

The method of calculating the probability of load exceeding available capacity shall include consideration of uncertainty in prediction of load and shall employ the best available statistical data on generator forced outage rates. The method will also consider hour-by-hour characteristics of the load, availability of quick-start generation and effects of interconnections and agreements with neighboring companies. There shall be no greater dependence upon interconnections with adjacent areas than is agreed to by said areas or is deemed prudent by good engineering judgment. The maximum capability assigned to any generating unit shall be that which has been demonstrated by actual test under the most adverse conditions that might exist during the loading period being considered.
- II. Special Design Features

Certain generating unit or plant design features have significant effects on system reliability and, therefore, are recommended herein.

 - A. All generating units, where practicable, should be designed such that generation can be instantly changed from 100% to the auxiliary load without the unit tripping.
 - B. Auxiliary power sources shall be provided in each major generating station to provide for the safe shutdown of all the units in the event of an emergency or system collapse.
 - C. In each major load area of the Southwest Power Pool, a unit capable of "black start" shall be provided having the capability of restarting the other units in the area.
 - D. Boiler controls and other essential automation of major generating units shall be designed to withstand voltage dips caused by system short circuits.
- III. Fuel Supply

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of a standby fuel shall be provided, when practicable, to permit normal system operation based on experience relative to curtailments and interruptions.

Principals of Transmission Planning

The bulk transmission system should be planned so that instability or cascading outages will not occur. Within the Southwest Power

Pool there are various sub-areas having natural electrical boundaries and large amounts of load which could become isolated in the event of a severe system disturbance. These sub-areas can include portions of all of one or more companies. The criteria for planning transmission additions for the sub-areas in the Southwest Power Pool system are set forth in this section.

- I. Each sub-area shall maintain service continuity after the loss of the single most important system component (either transmission line or generating unit), taking into account planned maintenance schedules.
- II. Stability shall be maintained between the sub-area and neighboring systems when the loss of the system component described in Subsection I of this section was caused by a three-phase fault at the worst location cleared in 0.1 second.
- III. A sub-area may suffer interruption of load as a result of less probable contingencies; however, such contingencies should not result in the collapse of the Southwest Power Pool system. These less probable contingencies shall include, but not be limited to, the following:
 - A. The loss of a complete substation or switching station (all equipment of one voltage).
 - B. The loss of all units in a generating station which have in common such components as transmission substation, control room, fuel supply, etc.
 - C. The loss of all transmission lines on a common right-of-way.
 - D. The loss of any two generating units in the same sub-area during annual peak conditions (whether scheduled or not).
 - E. The loss of any two transmission lines in the same sub-area during annual peak conditions.

Principles of Protective Relaying, Communications and Instrumentation Planning

Protective relaying, communications and instrumentation play an important role in maintaining the reliability of the bulk power supply. The principles for planning additions in these categories are set forth in the section.

- I. The bulk power protective relay system design shall have as its objective rapid clearing of all faults, with no fault permitted to remain uncleared despite the failure of any single protective system component. To accomplish this, relay and breaker failure protection shall be provided on all new installations. As obsolescence occurs in older installations, they shall be modified so as to conform to this criterion. It shall be the Southwest Power Pool's policy to have its control areas maintain communications systems to their generating stations and operating centers and to neighboring utilities which will provide adequate communication in the event of failure of any one element of the system and which will not be susceptible to failure during a failure of the a.c. power supply in any part or all of their areas.
- II. Loadings on the bulk power supply system must be monitored continually to ensure that operation is within safe limits.
 - A. Suitable instrumentation shall be installed to measure appropriate quantities at key points in the system with suitable automatic alarms.
 - B. Automatic oscillographs with pre-fault capability shall be installed at appropriate points within Southwest Power Pool so that outages and short circuits can be analyzed and protective relay performance studied.
- III.

Joint Planning and Adjoining Regions

It shall be the policy of Southwest Power Pool to maintain as high an interconnection capability with adjoining regions as is economically prudent. These interconnections with adjoining regions shall be designed so that the Southwest Power Pool will remain interconnected following all of the more probable transmission and generation outage contingencies set forth in the Principles of Transmission Planning Section. It is recognized that emergencies that occur in adjoining regions can affect Southwest Power Pool, just as the emergencies within Southwest Power Pool can affect adjoining regions. Therefore, joint

studies will be made on a regular basis to investigate various system emergencies that can occur and their effects on the various systems involved. In this way, the effectiveness of existing and planned interconnections will be periodically measured and the design of the system periodically updated so that the interconnection capability and reliability will be maintained.

WSCC RELIABILITY CRITERIA

Introduction

The Western Systems Coordinating Council was established to provide a forum for the coordination of design and operation of the member systems to promote reliability of power supply.

Article V, Section 1, of the Council Agreement reads, "For the guidance of the members and subject to the review of the Executive Committee, the Planning Coordination Committee shall recommend criteria for such elements of system design as affect the reliability of the interconnected bulk power systems, and the Operations Committee shall recommend such operating procedures as affect the reliability of the interconnected bulk power systems."

In order to accomplish its assignment, the Planning Coordination Committee established the Reliability Criteria for System Design Subcommittee. This document is the result of work by the Subcommittee.

Definitions

Cascading: The uncontrolled successive loss of system elements.

Disturbance: An unplanned event that causes an abnormal system condition.

Element: Any component of a system that can be represented in a simulation study.

Interconnection: An electrical connection between systems.

Island: An isolated portion of the interconnected systems.

Readjustment: Manual or automatic dispatching action taken to improve the reliability of the system after a disturbance.

Remedial Action: Special corrective measures, other than conventional practice, used to minimize the effects of a disturbance. Typical examples of this are generating dropping, controlled load dropping, controlled opening of interconnections and/or other lines including system islanding.

System: The integrated electrical generation and transmission facilities owned or controlled by one member.

Philosophy of Criteria

The criteria in this document are for the purpose of setting forth performance levels of the interconnected systems.

It is recognized that it is impossible to provide 100 percent reliability of power supply. Within a single system, it is expected that each member will, insofar as practical, protect its customers against loss of service. With the development of the complex interconnected systems, it is likely that a disturbance on one system will be reflected in varying degrees on other systems. The setting of limits of this effect on other systems is the objective of the criteria in this document.

Each member of the Council, each Pool or other group of Council members may have criteria which differ from the criteria presented in this document. Such difference may be justified by the geography of the area, type of load being served, system configuration, weather consideration, or other reasons. It is not required that such individual system criteria be changed to conform to this Council criteria for the evaluation of that system's performance following disturbance or operating conditions on its own system.

Within the framework of the WSCC, two or more systems may form a group for convenience of planning and operation. Such groups may agree to apply criteria within the group, for internal disturbances, that differ from the WSCC criteria. This is not intended to relieve any WSCC member system of its responsibility to apply WSCC criteria for disturbances on its system and resultant effects on other members outside the group.

Reliability criteria may be defined and measured in terms of the performance of a system under conditions of stress. Prediction of performance required simulation testing because actual tests cannot be made on systems not yet existing and tests on existing systems may impose unnecessary and unacceptable risks.

Continuity of service to loads is the primary objective of the

Council Reliability Criteria. Preservation of interconnected operation during disturbances is secondary to the primary requirement of preservation of service to loads.

The criteria are based on the understanding that there should be no loss of load on a system for the more common single contingency disturbances originating on other systems. There are disturbances that are credible but of low probability for which it is not feasible to protect the systems against islanding and/or loss of load. These criteria recognize the necessity for islanding and load shedding for certain contingencies, but such islanding and load shedding should be controlled so as to limit the adverse impact of the disturbance and to leave the systems in such condition as to permit rapid load restoration and re-establishment of interconnections. Cascading is unacceptable even under the most adverse credible disturbance.

Automatic line reclosing is employed by many member systems to enhance the reliability of the network. When reclosing is used, the network performance should be tested for unsuccessful reclosure. It is the intent of the Criteria that unsuccessful reclosing should not cause a disturbance more severe than the level required by these Criteria for the initiating disturbance.

Application of Criteria

It is recognized that at present the interconnected WSCC systems will not meet these criteria in all cases.

System additions that affect the reliability of the bulk power systems will be evaluated in accordance with these criteria and results reported to the Council. It is expected that eventually these criteria will be met, except where alternatively provided for by special agreement.

It is intended that these criteria be periodically reviewed and revised as experience indicates.

Criteria for Transmission System Capacity

Article V, Section 2 and 3 of the WSCC Agreement provide that each member system will inform the Executive Committee of its plans and operating procedures that may significantly affect the reliability of operation of the interconnected bulk power systems.

Insofar as reliability is concerned, each member system should be designed on the basis of adherence to the following principles.

- I. Each member system should provide sufficient transmission capacity within its system to serve its load and meet its transmission obligation to others without relying on or without imposing an undue degradation of reliability on any other system, unless pursuant to prior agreement with the system(s) so affected.
- II. Each member should provide sufficient transmission capacity, by ownership or agreement, for scheduled power transfers between its system and any other system. In transferring such power there should be no undue degradation of reliability on any system not a party to the transfer.
- III. A member should not participate in power transfers between its system and any other systems, which in the absence of loop power flows, would rely on or impose an undue degradation of reliability on parallel transmission capacity of any other system, except pursuant to prior agreement with affected system(s).

When the foregoing has been met, the mere existence of power flows on circuits other than their scheduled routes (loop flow, circulating flow) should not necessarily be regarded as reliance upon or undue degradation of the transmission capacity of another system.
- IV. Each member system should provide, by ownership or agreement, sufficient reactive capacity and voltage control facilities to satisfy the requirements of its own system without imposing an undue burden upon neighboring systems.

Technical studies should be performed to verify adherence to these four principles.

Criteria for Dynamic Performance of Interconnected Bulk Power Systems

The criteria for dynamic performance are established in terms of results of simulation tests. These are three main factors which have

been considered in defining the criteria. These are (I) Performance Levels, (II) Pre-Disturbance System Conditions and (III) A Disturbance-Performance Table which is the heart of these criteria.

I. Performance Levels

The performance levels for interconnected bulk power systems logically range between a level having no appreciable adverse system effects and a level where all remedial actions have been taken and load dropping and islanding may take place. The letters A, B, C, and D were selected to represent this range of performance.

The A, B, C, and D performance levels are defined in terms of actions or conditions that are permitted or may be necessary on systems other than one in which the disturbance originated.

Performance Level A allows post-disturbance line loadings and substation voltages to exceed normal limits but not emergency limits prior to system readjustment, requires no remedial action or abnormal system performance.

Performance Level B permits some remedial action but limits such action to dropping of interruptible load and generator dropping or the equivalent reduction of energy to the system.

Performance Level C allows further remedial actions such as controlled opening of interconnected and/or other lines, system islanding and attendant underfrequency load dropping if required.

Performance Level D, the lowest level, may require additional remedial action beyond that of Performance Level C. These remedial actions are controlled dropping of firm load, islanding and generation separation if necessary. At Performance Level D, post-disturbance transmission loadings and substation voltages may have excursions outside of emergency limits prior to readjustment.

The above performance levels are summarized for convenient reference with the Disturbance-Performance Table.

In the application of remedial actions to limit the severity or extent of any foreseeable system disturbance, all systems are expected to cooperate in taking any reasonable remedial actions.

II. Pre-Disturbance System Conditions

For a simulation test case, the interconnected transmission system steady-state loading conditions prior to a disturbance should be appropriate to the case and at a location on the system disturbed that results in maximum stress on other systems. The principles set forth under "Criteria for Transmission System Capacity" will be given consideration in establishing steady-state loading conditions. Pre-disturbance conditions will be normal except for the system on which the test is made which may have a prior condition such as a generator or line outage necessitating operation at emergency levels.

Relay action, fault clearing time, and reclosing practice will be represented in the simulated tests according to the design and operation of the actual planned systems.

It is recognized that the amount, type, and location of spinning reserve will have an effect on the interconnected system reliability. It is further recognized that criteria for determining such reserves is the responsibility of the Operations Committee. Information from system studies relating to the importance of the amount, response, rate and location of spinning reserves on interconnected system reliability will be given to the Operations Committee for its use.

III. Disturbance-Performance Table

The quality of dynamic performance to be expected under simulation tests is presented in the Disturbance-Performance Table. This table defines performance to be expected for a given type of initiating disturbance under a particular condition. The table readily shows that a disturbance having a high probability of occurrence should result in excellent performance while less probably disturbance could result in a lower level of performance.

When experience proves that a given disturbance on a specific facility occurs more often than expected and results in a level less than "A" performance, the owners of the facility should take measures to reduce the frequency of

occurrence of the disturbance, and fully cooperate in taking remedial action to reduce the effects of such disturbance.

Notwithstanding the performance level shown in the Disturbance-Performance Table, where such performance can be improved it is expected that the systems involved will mutually review and agree on additional remedial measures to be taken. If the additional remedial measures cannot be agreed upon, the matter will be submitted to the Planning Coordination Committee for review and recommendation.

Types of initiating disturbances consisting of the loss of some system element are listed in the left-hand column of the table in more or less descending order of probability and increasing order of severity. The variable conditions under which the loss of these system elements may occur are given as column headings. One column (second from the left) treats the case of "no fault" — normal opening of a system element without a fault. Column 3 is similar to Column 2, except the element is assumed opened under permanent

fault condition. The remaining four columns (4 through 7) also deal with elements lost under permanent fault conditions but after the loss of either one generator or one line. In these cases the conditions of having the system readjusted or not readjusted are considered separately. For example, it is assumed under "System Readjusted" (Columns 4 and 6) that ample time is available for the system to be readjusted between the occurrence of losing a generator or line and having a permanent fault occur on another system element.

The performance level to be expected for specific disturbance under each listed condition is given in the appropriate space in the table by a letter A, B, C, or D as previously defined.

When multiple elements are named in the first column, they are assumed to be lost simultaneously. The loss of a generator with a prior system condition of one generator out should not be considered the loss of two generators. The loss of two generators is an entirely different disturbance with a different performance level.

WESTERN SYSTEMS COORDINATING COUNCIL
DISTURBANCE - PERFORMANCE TABLE

DISTURBANCE →	NO FAULT	3-Ø FAULT W/NORMAL CLEARING OR SLG FAULT W/STUCK BREAKER	3-Ø FAULT W/NORMAL CLEARING			
			ONE GENERATOR OUT		ONE LINE OUT	
			SYSTEM READJUSTED	NOT READJUSTED	SYSTEM READJUSTED	NOT READJUSTED
ELEMENTS LOST OR FAULTED ↓						
1. LOAD	A	A	A	A	A	A
2. TRANSFORMERS	A	A	A	A	A	B
3. LINE	A	A	A	A	B	C
4. GENERATOR	A	A	A	B	A	C
5. BUS SECTION	B	B	B	B	C	C
6. TWO GENERATORS	C	C	C	D	E	D
7. TWO LINES	C	C	C	D	C	D
8. ALL LINES ON RIGHT-OF-WAY	D	D	D	D	D	D
9. ENTIRE SUBSTATION	D	D	D	D	D	D
10. ENTIRE PLANT INCLUDING SWITCHYARD	D	D	D	D	D	D

SEPTEMBER 6, 1972

PERFORMANCE LEVELS

ALLOWABLE CONDITIONS OR ACTIONS ON INTERCONNECTED SYSTEMS (1)	PERFORMANCE LEVEL (2)			
	A	B	C	D
REMEDIAL ACTION	NO	AS PERMITTED BELOW		
DROPPING OF INTERRUPTIBLE LOAD	NO	YES	YES	YES
GEN. DROPPING OR EQUIVALENT REDUCTION OF ENERGY INPUT TO THE SYSTEM	NO	YES	YES	YES
CONTROLLED OPENING OF INTER- CONNECTIONS AND/OR OTHER LINES INCLUDING SYSTEM ISLANDING AND ATTENDANT UNDER-FREQUENCY LOAD DROPPING IF REQUIRED	NO	NO	YES	YES
CONTROLLED DROPPING OF FIRM LOAD	NO	NO	NO	YES
SUB ISLANDING AND GENERATION SEPARATION MAY OCCUR	NO	NO	NO	YES
POST DISTURBANCE LOADINGS AND VOLTAGES OUTSIDE OF EMERGENCY LIMITS PRIOR TO READJUSTMENT	NO	NO	NO	YES

APRIL 10, 1971

(1) ACTION OR CONDITIONS ON SYSTEMS OTHER THAN ONE ON WHICH DISTURBANCE OCCURRED

(2) A "YES" INDICATES THE ACTION OR CONDITION IS PERMITTED IN SIMULATION TESTING TO MEET THE PERFORMANCE LEVEL IF REQUIRED TO PREVENT CASCADING A "NO" INDICATES THAT THE ACTION OR CONDITION IS NOT ALLOWED

TABLE 1
INSTALLED GENERATING CAPACITY REQUIREMENTS

	ERCOT	MAAC	MARCA	NPCC	SPP
Fixed Reserve - % of Load	15%	--	12% 10% if Hydro		15%
Probability Calculated	No	Yes	Review Periodically	Yes	No
Allowable Frequency of Loss of Load		1d/10 yr		Each area 1d/10 yrs	1d/10 yr
Factors considered per criteria					
<u>Generators</u>					
Forced outages		X	X	X	X
Maintenance outages		X	X	X	
Limited energy capacity		X			
<u>Loads</u>					
Daily peak loads		X			X
Probability of forecast error		X	X		X
<u>Transmission</u>					
Internal transfer capabilities		X	X		X
Ties to other pools		X	X		X

Note: The absence of listing an item does not mean it is not considered. Other documents may apply.

* Available support from other areas within or outside council is not considered.

TABLE II
SUMMARY REGIONAL RELIABILITY CRITERIA SPECIFICATIONS

ECAR

Disturbance	3 ϕ Fault with delayed clearing					
Prior System Conditions	Normal	No of Generators Out	No of Transmission Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted		Yes	Yes No	Yes	Yes	
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend					
1. Load	T	I	I			
2. Transformer		I	I			
3. Line		3 I T	I			
4. Generator		2 I T	I			
5. Bus Section		I	I			
6. Two Generators		I	I			
7. Two Lines		2 I T	1 I T			
8. Entire Substation	T	I	I			
9. Entire Plant Generation	T	I	I			
10. Line With Stuck Breaker		I	I			
11. All Lines from Substation		I	I			
12. All lines on same ROW	T	I	I			
13. Circuit Breaker (Faulted)		I	I			

ERCOT

Disturbance	3 ϕ Fault with normal clearing					
Prior System Conditions	Normal	No of Generators Out	No of Transmission Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted		Yes	Yes No	Yes	Yes	
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend					
1. Load	P	I	I			
2. Transformer	P	I	I			
3. Line	P	I P	I P			
4. Generator	P	I P	I P			
5. Bus Section	P	I	I			
6. Two Generators	P	I	I			
7. Two Lines	P	I	I			
8. Entire Substation		I	I			
9. Entire Plant Generation	P	I	I			
10. Line With Stuck Breaker		I	I			
11. All Lines from Substation		I	I			
12. All lines on same ROW		I	I			
13. Circuit Breaker (Faulted)		I	I			

LEGEND:

- W - Post disturbance loadings and voltages within emergency limits and readjustable to normal limits.
- X - Post disturbance loadings and voltages within short time emergency limits and readjustable to longer time limits.
- T - Test system's ability to withstand without widespread cascading. (Does not mean situation will be corrected.)
- C - Should avoid widespread cascading. Load may be dropped
- P - Planned to avoid cascading.
- M - Minimize spread of interruption.

SUMMARY REGIONAL RELIABILITY CRITERIA SPECIFICATIONS

MAAC								
Disturbance	3 ϕ Fault with normal clearing or 1 ϕ -G Fault with delayed clearing							
Prior System Conditions	Normal	No of	Generators Out	No of	Transmission Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted			Yes		Yes No	Yes	Yes	
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend							
1. Load	T	1		1				
2. Transformer	W	1	W	1	W			
3. Line	W	1	W	1	W	T	W	W
4. Generator	W	1	W	1	W		W	W
5. Bus Section	W	1	W	1	W			
6. Two Generators								
7. Two Lines	X	1	X					
8. Entire Substation	T							
9. Entire Plant Generation	T							
10. Line With Stuck Breaker	X	1	X					
11. All Lines from Substation	T*							
12. All lines on same ROW	T							
13. Circuit Breaker (Faulted)								

Also Test "T" for 3 ϕ Fault with Delayed Clearing

* of same voltage only

MAIN								
Disturbance	3 ϕ Fault with delayed clearing							
Prior System Conditions	Normal	No of	Generators Out	No of	Transmission Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted			Yes		Yes No	Yes	Yes	
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend							
1. Load	T	1						
2. Transformer		3	T					
3. Line		2	T					
4. Generator								
5. Bus Section								
6. Two Generators								
7. Two Lines		2	T	T	T			
8. Entire Substation	T							
9. Entire Plant Generation	T							
10. Line With Stuck Breaker								
11. All Lines from Substation								
12. All lines on same ROW	T							
13. Circuit Breaker (Faulted)								

LEGEND:

- W - Post disturbance loadings and voltages within emergency limits and readjustable to normal limits.
- X - Post disturbance loadings and voltages within short time emergency limits and readjustable to longer time limits.
- T - Test system's ability to withstand without widespread cascading. (Does not mean situation will be corrected.)
- C - Should avoid widespread cascading. Load may be dropped
- P - Planned to avoid cascading.
- M - Minimize spread of interruption.

SUMMARY REGIONAL RELIABILITY CRITERIA SPECIFICATIONS

MARCA

Disturbance	3 ϕ Fault with normal clearing or 1 ϕ -G Fault with delayed clearing					
Prior System Conditions	Normal	No Generators of Out	No Transmission of Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted		Yes	Yes No	Yes	Yes	Yes
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend					
1. Load	T+M	1	1			
2. Transformer		1 W	1 W		W	
3. Line		1 W	1 W		W	
4. Generator		1 W	1 W		W	
5. Bus Section		1 W	1 W		W	
6. Two Generators		1	1			
7. Two Lines		1	1			
8. Entire Substation	T+M	1	1			
9. Entire Plant Generation	T+M	1	1			
10. Line With Stuck Breaker		1	1			
11. All Lines from Substation		1	1			
12. All lines on same ROW	T+M	1	1			
13. Circuit Breaker (Faulted)		1	1			

NPCC

Disturbance	3 ϕ Fault with normal clearing or 1 ϕ -G Fault with delayed clearing					
Prior System Conditions	Normal	No Generators of Out	No Transmission of Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted		Yes	Yes No	Yes	Yes	Yes
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend					
1. Load	T+M	1	1			
2. Transformer	T+M*	1 W or X	1 W or X		W or X	
3. Line	T+M*	1 W or X	1 W or X		W or X	
4. Generator	T+M*	1 W or X	1 W or X		W or X	
5. Bus Section	T+M*	1 W or X	1 W or X		W or X	
6. Two Generators		1	1			
7. Two Lines		1 W or X	1 W or X		W or X	
8. Entire Substation	T+M	1	1			
9. Entire Plant Generation	T+M	1	1			
10. Line With Stuck Breaker		1	1			
11. All Lines from Substation		1	1			
12. All lines on same ROW	T+M	1	1			
13. Circuit Breaker (Faulted)		1 W or X	1 W or X		W or X	

* with 3 ϕ fault and delayed clearing

LEGEND:

- W - Post disturbance loadings and voltages within emergency limits and readjustable to normal limits.
 X - Post disturbance loadings and voltages within short time emergency limits and readjustable to longer time limits.
 T - Test system's ability to withstand without widespread cascading. (Does not mean situation will be corrected.)
 C - Should avoid widespread cascading. Load may be dropped
 P - Planned to avoid cascading.
 M - Minimize spread of interruption.

SUMMARY REGIONAL RELIABILITY CRITERIA SPECIFICATIONS

SERC

Disturbance	3 ϕ Fault with delayed clearing					
Prior System Conditions	Normal	No Generators of Out	No Transmission of Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted		Yes	Yes No	Yes	Yes	Yes
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend					
1. Load	P					
2. Transformer				P		
3. Line						
4. Generator						
5. Bus Section						
6. Two Generators						
7. Two Lines						
8. Entire Substation	P*					
9. Entire Plant Generation	P					
10. Line With Stuck Breaker						
11. All Lines from Substation	P					
12. All lines on same ROW						
13. Circuit Breaker (Faulted)						

*One voltage level only

SPP

Disturbance	3 ϕ Fault with normal clearing in 0.1 seconds					
Prior System Conditions	Normal	No Generators of Out	No Transmission of Lines Out	Transformers One Out	Bus Section One Out	
System Readjusted		Yes	Yes No	Yes	Yes	Yes
Elements Lost or Faulted	Post Disturbance Conditions Specified - See Legend					
1. Load						
2. Transformer						
3. Line		1 W	1 W			
4. Generator						
5. Bus Section						
6. Two Generators	C					
7. Two Lines	C					
8. Entire Substation	C*					
9. Entire Plant Generation	C					
10. Line With Stuck Breaker						
11. All Lines from Substation						
12. All lines on same ROW	C					
13. Circuit Breaker						

*One voltage level only

LEGEND:

- W - Post disturbance loadings and voltages within emergency limits and readjustable to normal limits.
 X - Post disturbance loadings and voltages within short time emergency limits and readjustable to longer time limits.
 T - Test system's ability to withstand without widespread cascading. (Does not mean situation will be corrected.)
 C - Should avoid widespread cascading. Load may be dropped
 P - Planned to avoid cascading.
 M - Minimize spread of interruption.

APPENDICES
OF
IBM Research Center

APPENDIX A

Data Base Concepts

This appendix discusses some concepts and objectives of data base design and gives a brief description of some file and data base organizations.

A.1 - Data Base Objectives

Unfortunately, data base terminology is not uniform, requiring us to make our own definitions.

A data base can be defined as any collection of related data, stored in one location in computer readable form, available to all authorized users. Such a definition includes most conventional power system engineering data bases.

A more restricted definition of a data base imposes the additional specification that the data be maintained in a nonredundant form to be processed by multiple applications. The data is organized in a predefined structure which retains relationships between data elements and minimizes or avoids redundancy. Different applications may have different views of the data base and access it differently. Such a definition excludes most conventional power system engineering data bases.

In both cases some of the objectives are the same:

1. Availability: The data is available in a known place either off-line or on-line according to need and is accessible without undue delay.
2. Data quality: The data is managed in a coordinated way and several aspects of data quality can be improved:
 - a. Standardization: This may involve agreements on the meaning, name, type and format of variables, on the content of the data base, and on its organization.
 - b. Validation: This may be supported in two ways: by an automatic program at the time of data entry or through a provision which limits the entry or update privilege to users most familiar with the data.
3. Central data management: In some cases, this simply means that binding decisions are made on definitions and format, on read and write privileges and other aspects of data usage. In other cases, this implies the existence of a data base management system, i.e., software to support the

creations, maintenance and reorganization of the data base, to allow backup, recovery, access control, and so forth. A data definition language and a data manipulation language may be available.

4. Ease of use and increased user productivity: This is meant relative to a situation where data is kept by different individuals and groups, not even always in machine-readable form. If one uses the term data base in the more restricted sense, it is usually in the context of a "data base system," in which other design criteria are important among which:

5. Controlled Redundancy: While there are at times economic or technical reasons for redundant storage, the goal is to store every data element only once. This has three beneficial effects:

- a. Storage requirements are reduced
- b. Data consistency is improved
- c. Data updating is facilitated

In the power systems environment this objective is rarely achieved. Multiple use of the same data, whether one or different applications are involved, usually implies multiple copies.

6. Data independence: This concept in its ideal form implies that no change in the data base organization should have an impact on any existing application program: Each user/application may have its own view of data. Separately, there exists a system view of all the data, represented in the data base organization. The translation between user views and the system representation is handled by the system. Figure A.1 illustrates the idea:

Figure A.1

This logical separation of application data views and the system data view constitutes the essence of the data oriented organization of a multiapplication data base, in contrast to an application oriented file system.

This objective becomes only relevant, of course, if more than one application makes use of a given set of data.

Other objectives which normally are very important, are not critical in the context of a system planning data base: performance and multi-user access. With the exception of some possible on-line data use, performance in terms of response time is not an issue yet. Similarly, it can normally be assumed in most cases that the planning data base is accessed only by one user at a time.

A very detailed description of the objectives of a data base system is given by Martin [56].

A.2 - File and Data Base Organization

In the data base design and implementation process, after the functions, the required data, and the expected usage patterns have been identified, the logical and physical organization of the data base has to be chosen. These organizations can vary from a simple sequential file system to a hierarchical data organization. In the first case the user may never know how the data is actually stored, but just define his needs in terms of the logical hierarchical model.

This section gives a brief description of some common file and data base organizations. See Wiederholt [86], Martin [56], or Date [21] for more details.

1. Sequential File

This is the most commonly used file structure today in engineering application. Records are stored sequentially and can only be processed in that order. It is very efficient to read the whole file, but more selective operation, such as retrieval of one filed in all records, are not possible.

Figure A.2

For updating and insertion it is simplest to rewrite the file.

2. Indexed Sequential File

An indexed sequential file attempts to overcome the access problems of a sequential file: The file can be read sequentially, but certain records can also be accessed directly through an index. An index has as entries key attributes of some of the records and pointers to their location in the file. A specific record can be located by searching through the index for its address or that of neighbor record. For insertion of records there is some free space allocated in blocks across the file or at the end. Insertions can be found through a pointer from the index and from the predecessor record in the file.

Indices can be indexed themselves for multi-level indices.

Figure A.3

Indexed sequential files are useful if both sequential processing and selective access according to the key ("Bus 89") is considered. They also allow relatively easy updating. This file organization could be suitable for a data base organization as described in Appendix B.

3. Indexed File

This file can be accessed through one of several indices, sequential access is not considered.

Figure A.4

For each of a set of search attributes an exhaustive index to all elements of interest is provided. This organization might be useful in a query environment. Similar files are used in FERC's SYSTEM 2000. In data base systems,

the user is no longer concerned with the physical storage of data, he describes his operations in terms of a logical data base model. We briefly describe three common logical data models: the relational, hierarchical, and network model. (See Date [21] for a general reference.)

1. Relational Model: A relation is a table of values. Each row represents one "record," each column represents a different "field" Rows are identified by a key.

Name	#	Voltage	Angle	...
B1	1	113.5	6.2	..
B3	3	344	9.1	
B8	8	345.5	-1.2	

Figure A.5

Operations on the data base are expressed as operations on the table (or tables): addition/deletion of rows, selection of subsets of columns, creation of new tables from old ones, and so forth.

The appeal of the relational model lies in its simplicity. It corresponds to the natural view engineers have of their data. Since there is a minimum of structure imposed on the data, this organization is often used in query systems where it is not desirable to prefer certain accesses over others. An example of the use of this model is described by Peon [68] and by D'Ettorre [23].

2. Hierarchical Model: The records in a hierarchical organization are represented by a tree of subrecords of various types. Figure A.6 gives an example of load flow file hierarchy.

Data may be retrieved by specifying a first subrecord to be retrieved, then requesting additional subrecords in a given order. Access for certain retrievals becomes very efficient, as for example for the request of all branches connected to a certain bus. However, a report of all those generators which are never loaded less than 80%, requires checking all the loading subrecords which cannot be accessed efficiently unless a special provision was made for it. Hierarchical data models are commonly used in commercial applications.

Figure A.6

3. Network Model: The network model generalizes the hierarchical model by allowing more general relationships than those expressed by a tree. This means a subrecord can depend on more than one other subrecord as, e.g., in Fig. A.7. This means that a subrecord can now be accessed in more than one way.

Figure A.7

In both the hierarchical and network model, the model defines the access paths. Thus, some retrievals can be made more efficiently than others. In the relational model no access paths are explicit parts of the model.

APPENDIX B

Description of Three Regional Data Bases

This appendix describes in some detail three implementations of regional data bases. They differ in the way in which they are intended to be used and hence in the form and complexity of their data base design.

The first example describes the structure of a typical library of load flow cases as it exists at more reliability councils. Since all load flow formats are essentially very similar, only a representative description of the

structure will be given.

The second example describes the data base operation at NPCC where some additional data is stored and a more flexible data use is intended. The additional data is stored and a more flexible data use is intended. The data base organization consists of a system of indexed files which allow rapid retrieval of records according to one key. The files do not reflect their intended end use.

The third example describes the data management at Electricite de France (EDF) and the organization of their centralized planning data base. This data is used for medium to long-term planning studies. The data is essentially organized as a large set of hierarchically structured files.

The purpose of this appendix is to exhibit some of the details of these data bases in doing so, lead the reader through a progression of more complex data use and data organization.

B.1 - Data Base as a Load Flow Base Case Library

General: Such a library of base cases exists at several of the U.S. reliability councils or at the organizations who manage the data for them. The approach is essentially system independent as all that is required is to be able to read and write sequential files from a high level language like FORTRAN.

Data Base Content: Generally one load flow case is described by three files: a bus file, a branch file and an area file. Each file is a sequential file of records with each record containing the identification and attributes of an element. From the point of view of file organization, the maximum number of elements is essentially unconstrained. The implicit constraint which usually exists is the capacity of the load flow program. An example of a large system is the NERC system whose files contain up to 8,000 buses and 12,000 lines.

The files do not contain an internal reference to time other than possibly in the title. Therefore, the different cases are externally labeled. The typical situation is to have summer and winter peak load cases for five to ten years into the future.

The three files typically contain the following information:

1. Bus File

Identification: number, name, owner,

nominal voltage, type, area/zone.

Parameters: generation - P, Q, Qmax, Qmin, Pmax, controlled bus load - P, Q; shunt - real, reactive/capacitive; voltage magnitude, angle, Vmax, Vmin.

2. Branch File

Identification: bus 1, bus 2, owner, circuit id, area, metered bus

Parameters: impedance (R, X, B) MVA ratings (for transformers) - tapinfo (ρ , ρ_{max} , ρ_{min} , β , step size), controlled bus.

3. Area File

Identification: area name and number, slack bus, export, tolerance.

This example does not include every element which is represented or same data bases (DC lines, multisegment lines). Neither do we consider different formats. The points to be made here are: (1) that the data is set up to serve the load flow application; and (2) that with any number of cases bigger than 1, a certain degree of redundancy is unavoidable.

Data Organization

The three logical files are usually part of one sequential file, separated by a delimiter (d).

Busfile				Branchfile				Areafile			
R1	R2	...	d	R1	R2	...	d	R1	R2	...	d

Access

Figure B.1

Data Entry and Validation

Different data collection and validation schemes exist but normally they are similar to the one described for NPCC in the next section. For updating, the whole file is read into core and written back out after the changes are made.

Data Base Access

Access to the data base is local only. Usually there are no built in access controls. Note: This is generally true, but has nothing to do with the data base organization.

Data Retrieval

Data retrieval exists basically in one form: The whole file is read or up to

the data of interest.

B.2 - Data Base System at NPCC

General

This system which is still under development is being designed by Westinghouse. It is written in FORTRAN and can be used on several manufacturer's computers. Most information presented here is based on [67] and private communications.

Data Base Content

The data base can accommodate data for 7,500 buses and shunt devices, 12,000 lines, 3,000 transformers, 3,000 fixed output generators, and 2,000 variable output generators, and 100 areas. The time span covered by the data in the data base is 20 years.

The data base consists of ten files with the following detailed content:

1. Bus File:
System bus number
System bus name
Company number
Area number
In-service and retirement dates
Base KV
Priority for representation level
Automatic VAR control request
Desired voltage

2. Bus Load File:
System bus number
Year number for load data
MW and MVAR loads for various load levels

This data is specified for each bus and for each year. For the first six years there are six load levels represented, for the remaining 14 years, two load levels.

3. Variable Output Generator File:
System bus number
Unit name and number
In-service and retirement dates
Controlled bus number and desired voltage
Minimum and maximum MVAR limits
Unit status, type, and manufacturer
Unit minimum generation
Unit net full load capability
Unit assured reserved capability
Unit average full load heat rate
Unit fuel cost
Unit incremental heat rate by blocks
Unit must run (Yes or No)

4. Fixed Output Generator File:
System bus number
Unit name and number

In-service and retirement date
Maximum net output of unit
Unit status, type and manufacturer

5. Fixed Output Generator Station File:
System bus number
Year number for generation data
Controlled bus and desired voltage
MW generation for various load levels
Minimum and maximum MVAR generation for various load levels
This data is specified for each year of the 20 years.

6. Transmission Line File:
"TO" and "FROM" system bus numbers
Circuit number
In-Service and retirement dates
Loss area number
MVA ratings, normal and emergency
Tie line meter bus
Positive sequence resistance and reactance
Line charging
Voltage
Status, construction type, and length
Conductor size and type

7. Transformer File:
Tap bus number
Impedance bus number
Transformer bank number
In-service and retirement dates
Loss area number
Controlled bus number and desired voltage
Control side (T or Z)
Transformer type
Tie line meter bus
Positive sequence resistance and reactance
MVA ratings, normal and emergency
Initial tap ratio/angle
Minimum and maximum tap ratio/angle
Step size of tap/angle
Minimum and maximum voltage, MVAR, or MW
Phase shift impedance at minimum and maximum angles

8. Shunt File (General Data)
System bus number
Shunt bank number
In-service and retirement dates
Type
Bank size
This data may be specified for several banks.

9. Shunt File: (Admittance)
System bus number
Year Number for shunt data
Season (S or W)
Shunt conductance and susceptance data for various load levels
Shunt data can be specified for each of the 20 years.

10. Area File
 - Area slack bus number
 - Area number
 - Area name
 - Area spinning reserve
 - Loss area number
 - Loss area name
 - Area spinning reserve can be entered for all 20 years by seasons.

with a subset of buses and a subset of years. The data is printed.

- c. Data retrieval for preparation of a load flow study. The study is specified by year, season, and load level. This data is put into a study file. Load levels can be modified by areas.

Data Base Organization

Apparently the files are FORTRAN direct-access files and can thus be viewed as a simple form of an indexed sequential file. They are all stored on disk.

Figure B.2

Data Entry and Validation

The yearly (or semi-annual) update information is collected by four regional data coordinators who establish a first level of validity and consistency. Then the data is submitted to a NPCC data controller who is authorized to update the data base. After the update, listings of the updated files are sent back to the region for review.

Change information is submitted on cards or on tape in card image format.

Data Base Access

Access to the data base is either local or through remote job entry (RJE) from a remote terminal. All operations are batch operations.

Security provisions exist to avoid unauthorized updates.

Data Retrieval

Several retrieval options exist:

- a. Listing of one or several files. Selection by year is possible. The data is printed.
- b. Listing of all data associated

This data is processed by a generator scheduling program which allocates the generation to the variable output generators and produces a load flow input file.

After a load flow has been run, the system can be reduced by specifying for each area the level of detail (1 through 5) which should be retained. Load flow results can be obtained both in COMMON and Westinghouse format.

B.3 Data Base System at EDF (Electricite de France)

General

The central planning data base of EDF contains the planning data of all regional planning centers in France which are connected to the central data base via telecommunications both for interactive and RJE operations. The central system is implemented on IBM equipment. It was planned to be operational by the end of 1975. The reference for this summary is Auges [2].

Data Base Content and Organization

The data base does not seem to have a fixed upper limit on any elements, but contains about 4,000 lines or transformer, 500 steam generators, 1,500 hydro generators and an appropriate number of shunt compensators, descriptions of special customers, and international exchange agreements. The data base consists of two sets of files; the first set describes the static system, the second set contains different load and generation cases.

(a) Static system files

Each file consists of several subfiles which can be accessed independently.

Figure B.3

The subfiles are implemented as one-, two- or three-level hierarchical files with at most one set of records at each level. If the top level is common to several files (i.e., same primary access), subfiles are partially combined.

Access to the entry on level one is by direct indexing (has coding); the second and third levels are reached by a chain of pointers. Examples of valid keys are shown in Fig. B.3.

Below follows a list of files with their subfiles and the available keys. (Keys are usually of the type name = N, year = y, type = T.)

1. Substation
 - Characteristics (N,Y)
 - List of nodes (N,Y,N)
 - List of lines (N,N)
 - List of transformers (N,N)
 - List of thermal groups (N,N)
 - List of hydraulic groups (N,N)
 - List of loads (N,N)
 - List of international exchanges (N,N)

This file seems to serve primarily as a directory to the following files.

2. Lines and Cables
 - Topology (N,Y)
 - Electrical characteristics (N,Y)
 - Pieces of a line (N,Y)
 - Pieces of a line (N,Y)
 - Operational characteristics (N,Y)
 - Line electrical characteristics (N)
 - Forced unavailability (N)
 - Scheduled unavailability (N,Y)

3. Transformers
 - Topology (N,Y)
 - Electrical characteristic;
 - 2 windings (N,Y)
 - Electrical characteristics;
 - 3 windings (N,Y)
 - Electrical characteristics (N)
 - Forced unavailability (N)
 - Scheduled unavailability (N,Y)
4. Thermal Generators
 - Topology (N,Y)
 - Electrical characteristics (N,Y,T)
 - Economical characteristics (N,Y,T)
 - Operational characteristics (N,Y,T)
 - Dynamic characteristics:
 - regulators (N,Y)
 - Economical characteristics (N,Y)
 - Electrical characteristics (N)
 - Forced unavailability (N)
 - Scheduled unavailability (N,Y)
5. Hydro Generators
 - Topology (N,Y)
 - Electrical characteristics (N,Y,T)
 - Operational characteristics (N,Y,T)
 - Dynamic characteristics:
 - regulators (N,Y)
 - Electrical characteristics (N)
 - Forced unavailability (N)
6. Loads, Special Customers
 - Topology (N,Y)
 - Contract-characteristics (N,Y)
7. International Exchanges
 - Topology and characteristics (N,Y)

Load and Production Files the three types of files which make up this set are:

1. load files
2. exchange files
3. hydraulic production files

They are similarly organized as the two-or three-level hierarchical files, except that there are separate files for each year. This last feature makes sense because load and production is used on a per year basis and, since it tends to change every year, there is no redundancy to be concerned about.

Data Entry, Data Validation

The collection and validation of data is aided by a fixed card compatible format of each record.

Two levels of validation tests are carried out. On a first level, each record is checked individually against format requirement, legitimate names and value ranges. Since all formats are of similar structure, these tests can be carried out by a set of programs of uniform structure. Once all records pass this test, the data

is entered into the data base. In a second series of special preprogrammed tests, some aspects of data consistency across files is tested. Only when all tests have been successfully completed, is the data base opened to the user again.

Data Base Access

All data files reside on disk and can be accessed locally or from a remote location.

Limited interactive use of the data base is possible for reading and displaying of selected records, both locally and remotely. Additional interactive capability is reserved to the "executive manager" who is in charge of

updating the data base and of extracting nonstandard reports.

Data Retrieval

Besides the interactive of individual records, the main use of the data base comes from assembling input data for application programs.

The basic steps involve:

1. extraction of required data
2. elimination or equivalencing by reduction of unnecessary detail
3. reformatting for the purpose of a specific application.

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