BULK POWER TRANSMISSION STUDY

Volume I

Public Utility Commission of Texas

Electric Division

Economic Analysis Section

May 1988

The opinions and views expressed in this report do not necessarily represent the consensus position of the Public Utility Commission of Texas or its staff.

Public Utility Commission of Texas

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May 19, 1988

<u>RE: BULK POWER TRANSMISSION STUDY OF THE ERCOT SYSTEM</u>

Enclosed for your information is a copy of Volume I of the final report detailing research into the potential for increased energy efficiency and production cost reductions associated with increased levels of bulk power transactions among the major electric utilities within the Electric Reliability Council of Texas. Volumes II and IV which are appendices detailing the data, software, and background information associated with the study will be sent to you under separate cover.

Volume III, which contains detailed computer output some 2100 pages long, will not be generally distributed because it is subject to a confidentiality agreement between the PUCT and ERCOT. Interested ERCOT utilities may request a copy of Volume III, if they think it will be useful, or may review the Volume here in our offices at any convenient time. <u>Any other parties wishing to obtain a copy of or access to the results in Volume III must first receive written permission from and execute any necessary confidentiality agreements with ERCOT.</u> Direct contact with ERCOT should be addressed to:

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If, while reading this report, you note any errors, please let us know so that *errata* sheets can be prepared and distributed to others. For now, the following two corrections should be noted:

Page i, paragraph 3, line 3. <u>Smith</u> instead of Simth
Page 1-17, paragraph 1, line 6. <u>billion</u> instead of million

I hope the information contained in this report provides you with some useful insights into the potential for bulk power transactions in the State of Texas and enhanced electric system coordination. Should you have any questions or wish to discuss the report, please feel free to write or give me a call at (512) 458-0102.

Sincerely,

Bill Moore

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The study staff also gratefully acknowledges the assistance provided by the review committes listed in Appendix G; but especially the efforts of Brad Belk (LCRA), John Stout (HL&P), Don Deffebach (TU Electric), Scott Helyer (COA), Tom Simth (Public Citizen of Texas), Bob Wright (TIEC), Bill Avera (TIEC), and Tom Sweatman (ERCOT).

<u>Note</u>: Funding for this project was provided by the U.S. Department of Energy through the 1986 and 1987 State Energy Conservation Program.

Abstract

Recent developments in the evolution of electric power markets in Texas have brought about the need for a reexamination of operating policies. In particular, cogeneration development, reliability considerations, regional excess generating capacity problems, fuel market changes, construction cost escalation and a variety of health and environmental issues suggest that changes in bulk power transmission policies may be in order.

Several studies indicate that substantial cost savings have been realized through power pooling arrangements in various regions of the country. The purpose of this study is to estimate the fuel and cost savings which may be realized through enhanced operating coordination of the interconnected utilities in Texas. These savings are estimated by comparing the operating costs under conditions of no coordination with the operating costs under conditions of perfect coordination. Current operating policies involve a degree of coordination between these two extreme cases.

Results from the study indicate that there is a strong potential for increasing the level of bulk power transactions in the State and, consequently, reducing total annual operating costs. The numerical estimates are quite sensitive to a variety of assumptions regarding fuel prices, cogeneration development and demand.

This study involves a general model of the interconnected systems in the state and should not be viewed as a detailed planning model for individual utilities. The substantial savings identified by this study suggest that more detailed modeling may be in order.

This report is the result of a two-year study conducted by the staff of the Public Utility Commission of Texas under the State Energy Conservation Program. The project was funded by the United States Department of Energy.

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*Appendix C contains confidential information and can only be distributed to ERCOT members and those who receive permission from ERCOT.

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Abbreviations

Organization

AES . . . . Applied Energy System

BEPC . . . . Brazos Electric Power Cooperative

BPA . . . . Bonneville Power Administration

C&SW . . . . Central and South West Corporation

COA . . . . City of Austin

CP&L . . . . Central Power and Light

CPSB . . . . City Public Service Board of San Antonio

DOE . . . . Department of Energy

DRI . . . . Data Resources, Incorporated

EEI . . . . Electrical Engineering Institute

EPA . . . . Environmental Protection Agency

EPEC . . . . El Paso Electric Company

EPRI . . . . Electric Power Research Institute

ERCOT . . . . Electric Reliability Council of Texas

FCG . . . . Florida Electric Power Coordinating Group

FERC . . . . Federal Energy Regulatory Commission

GE . . . . General Electric

GSU . . . . Gulf States Utilities

HL&P . . . . Houston Lighting and Power

LCRA . . . . Lower Colorado River Authority

NEPOOL . . . . New England Power Pool

NRRI . . . . National Regulatory Research Institute

NYPP . . . . New York Power Pool

OPEC . . . . Organization of Petroleum Exporting Counties

PJM . . . . Pennsylvania - New Jersey - Maryland Interconnection

PSO . . . . Public Service of Oklahoma

PTI . . . . Power Technologies, Incorporated

PUCT . . . . Public Utility Commission of Texas

SEC . . . . Securities and Exchange Commission

SPP . . . . Southwest Power Pool

STNP . . . . South Texas Nuclear Project

SWEPCO . . . . Southwestern Electric Power Company

TIS . . . . Texas Interconnected System

TNP . . . . Texas-New Mexico Power Company

TUEC . . . . Texas Utilities Electric Company

WSCC . . . . Western Systems Coordinating Council

WTU . . . . West Texas Utilities

Unit and Term

AC . . . . Alternating Current

BTU . . . . British Thermal Unit

CCN . . . . Certificate of Convenience and Necessity

CLM . . . . Conservation and Load Management

CPU . . . . Central Processing Unit

DC . . . . Direct Current

FOB . . . . Free On Board

GWH . . . . Gigawatt-Hour

Hz . . . . Hertz

KV . . . . Kilovolt

KV/m . . . . Kilovolt Per Meter

KW . . . . Kilowatt

KWH . . . . Kilowatt-Hour

lb . . . . Pound

mA . . . . Milli-Ampere

MAPS/MWFLOW . . . . Multi-Area Production Simulation Program with Megawatt Flow

MMBTU . . . . Million BTU

MW . . . . Megawatt

MWH . . . . Megawatt-Hour

NESC . . . . National Electric Safety Code

O&M . . . . Operation And Maintenance

PURA . . . . Public Utility Regulatory Act

PURPA . . . . Public Utility Regulatory Policy Act

RFP . . . . Request For Proposal

US . . . . United States

USSR . . . . Union of Soviet Socialist Republics

WACOG . . . . Weighted Average Cost Of Gas

Chapter 1
Introduction

Prior to the "energy crisis" years of the early 1970s to the early 1980s, electric utilities in the United States operated in a very favorable environment. Low inflation, abundant inexpensive fuel supplies, and rapid technological improvements resulted in continual decreases in the real cost of producing, transmitting, and distributing electric power and energy. This cost decrease was often reflected in declining prices of electricity which led to steady increases in demand by residential, commercial, and industrial customers. Utility planning and operations were oriented toward an engineering approach for designing and building generation and transmission facilities to meet the increased demands. Most utilities were actively engaged in marketing programs that further encouraged customers to increase their use of electricity.

Although the utilities were usually regulated, there was relatively little antagonism between them and the various federal, state, and local regulatory authorities. Interconnections with adjacent utilities were constructed primarily to ensure system reliability and, by sharing reserve responsibilities, to reduce the amount of physical plant that each utility had to construct. Economic planning, beyond attempting to secure long-term low-cost fuel supplies, played a relatively minor role in making decisions about future supply alternatives. These circumstances were particularly true in Texas where no statewide regulatory authority existed and a seemingly endless supply of inexpensive natural gas was available. The emergence of nuclear powered generating plants seemed to hold the promise of even further declines in the cost of producing electricity in the growth-oriented economy of the State.

The energy crisis years, however, markedly changed the attitudes of customers and governmental authorities toward the electric utility industry. In Texas, these changes led to the 1975 passage of the Public Utility Regulatory Act (PURA) which created the Public Utility Commission of Texas (PUCT). Rapidly escalating natural gas prices, which were passed through to utility customers as fuel charges, resulted in intense public pressure for policies which would slow the increases in the price of electricity. Suddenly, utilities were expected to reverse their earlier marketing philosophies and assist customers in reducing their power and energy requirements through utility-sponsored conservation and load management (CLM) programs. Simultaneously, many utilities found it necessary to develop new capacity expansion plans that required long-term economic analyses of many competing fuel sources in order to diversify resource plans and end their almost total dependence on natural gas. This was given additional impetus with the passage of the Fuel Use Act in 1978 which prohibited further construction of base-load power plants using oil or natural gas as their primary boiler fuel.

By the early 1980s, in addition to conventional power plants, the utilities in Texas were confronted with yet another source of electric power and energy from cogeneration facilities located primarily along the Gulf Coast where many petrochemical plants were located. Most of these industries, because of their requirements for processed steam or other forms of heat, could cogenerate electricity from natural gas with a 20-30% relative improvement in efficiency compared to conventional generating units. In addition, utilities were required to purchase cogenerated power that was priced at or below the avoided cost of their next planned generation addition. For those utilities located in the same area, cogeneration could provide a reliable and less expensive source of both capacity and energy.

For the other utilities in the State, however, the situation was more complicated because of their geographical distance from the Gulf Coast. Any available cogenerated power would have to be transmitted over long distances, often using the facilities of other utilities to wheel the power. Potential conflicts between the purchasing utilities and the wheeling utilities led to the adoption of mandatory wheeling regulations by the PUCT and a method of calculating wheeling charges based principally on the average embedded costs of the affected transmission facilities. In part, these state regulations were necessary because the interconnected system which covers most of the State, the Electric Reliability Council of Texas (ERCOT), is intra-state and not subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

By the mid-1980s, several interrelated economic factors combined to produce a severe recession in the State and added to the growing complexity of utility planning. A precipitous drop in the world price of oil caused a serious cutback in the Texas petroleum industry and an increase in the volume of cheaper imported oil. In conjunction with the 1984 deregulation of most natural gas markets, the lower petroleum prices and increased competition among producers resulted in a sharp decrease in natural gas prices, particularly in the short-term spot market. While these decreases contributed to the growing recession, which was already causing a moderation in the growth of the demand for electricity, they also provided electric utilities with lower cost fuel for much of their existing generating capacity. Similarly, construction delays, large cost overruns, and uncertain licensing requirements for two large nuclear power plants contributed to a renewed interest in the use of existing gas-fired facilities, as well as cogenerated power which became less expensive as gas prices fell.

Although the entire State felt some of the effects of the recession, the impacts were much more pronounced in the oil producing regions of East and West Texas and the petrochemical and refining areas along the Gulf Coast. In these areas, the demand for electricity fell and the affected utilities found that they had substantial quantities of excess generating capacity -- a problem further compounded when two nuclear plants serving two non-ERCOT utilities in Texas became operational. In the Central Texas area, demand growth moderated but remained positive, and affected utilities responded with short-term deferrals of some of their planned capacity additions and a more intensive review of their long-term needs. The net result of all of these changes was an imbalance in the geographical distribution of electricity demand and supply, and an increase in the production cost differentials among the State's utilities.

In response to these observed disparities, the PUCT initiated this Bulk Power Transmission Study in early 1986 to analyze the present and expected configuration of the State's utility system and to investigate the feasibility of improving the efficiency of energy usage on a statewide basis. As part of the Texas State Energy Conservation Program (SECP), and after nearly two years of research and analysis, this report documents the methodologies used and presents the results of that study.

1.1 Issues Addressed in the Study

While this study was being designed, the Texas Legislature's Joint Special Committee on Cogeneration in Texas recommended that:

- The PUC should continue evaluation of the State's transmission system, access to the system, and its capacity to serve efficiently the long-term and short-term needs for the movement of bulk power.

and:

- Utilities and the PUC should pursue available means to improve interconnection of ERCOT with other reliability regions in a way that will allow economic transfers between regions. However, no action should be undertaken which could jeopardize the existing jurisdictional status of ERCOT utilities or endanger the reliability of the ERCOT grid.[1]

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[1] Joint Special Committee on Cogeneration in Texas, Final Report and Recommendations to the 70th Legislature, 1986.

In order to address the legislative concerns and the Commission's directions, six principal issues are addressed in this study: excess generating capacity, cogeneration, system reliability, wheeling, fuel market volatility, and health and environmental impacts. Each of these have potential impacts on the configuration and operation of the bulk power transmission system in the State. *(As used herein, the terms "bulk power system," "bulk power transmission system," "transmission system," or "system" should be interpreted to include all sources of electricity for the ERCOT utilities participating in the study and all transmission lines and facilities with capacities of 69 kilovolts (KV) or greater within the ERCOT system, unless the context clearly indicates otherwise.)*

While some of these issues have received extensive consideration by utility system planners in the past, others have received little attention from the utilities, ERCOT, or the PUCT. In keeping with their primary function, most of ERCOT's past transmission planning was devoted to emergency planning to maintain reliability, rather than to analyzing the potential for economic opportunities based on bulk power transactions. Similarly, some of these issues had received little previous statewide attention by the PUCT, but provided the impetus which led to this study.

1.1.1 Excess Generating Capacity

The presence of excess generating capacity in some areas of the State, coupled with continued growth in other areas, may provide opportunities to defer or avoid the construction of additional generation if the transmission system has sufficient capacity to move the power. In 1986, most utilities in ERCOT were anticipating capacity deficiencies and planning to construct over 16,000 MW of additional generating capacity between 1986 and 1995. However, by late 1987 the combined demand forecasts of the utilities in this study had fallen by 4,306 MW and their resource plans were revised to reflect this reduction. Currently, some of these utilities show little growth and are expected to have excess capacity available for sale. Although they are outside the ERCOT system, El Paso Electric Company (EPEC) and Gulf States Utilities (GSU) are also facing capacity surpluses with the completion of the Palo Verde and River Bend nuclear power plants, respectively. However, there are a number of technical and nontechnical impediments to interconnecting ERCOT and non-ERCOT utilities at the present time. In general, though, it appears that the transmission system could be used more extensively to balance electricity supply and demand in Texas.

1.1.2 Cogeneration

Currently, the State's cogeneration activity and future potential is concentrated along the Gulf Coast, particularly in the Houston area. There are many concerns that the present transmission network is technically inadequate to handle the movement of excess cogenerated power to areas of the State where such power might be marketable. The use of large amounts of cogeneration also raises questions about the provision and allocation of system reserves within ERCOT, and access to the transmission system by third parties.

1.1.3 Reliability

Historically, because of the cooperation and coordination of the ERCOT utilities, Texas has enjoyed an excellent level of reliability in the production and delivery of electricity. If new burdens are imposed on the existing transmission system as a result of increased energy exchanges among the utilities, care must be taken to maintain the high reliability of the system. Future planning efforts must explicitly recognize the trade-offs among system reliability, economic benefits, and implementation costs.

1.1.4 Wheeling

Wheeling issues continue to be quite controversial, particularly with the recent sale of a share of the Oklaunion power plant in Wilbarger County to the Public Utilities Board of Brownsville some 600 miles away. Other problems arise with the City of Austin's (COA) desire to import power from the Lubbock area and Texas Utilities Electric Company's (TUEC) purchase of Houston area cogeneration. In each of these instances, transmission lines of third-party utilities must be used to transmit the power from its origin to the load it is intended to serve. The methodology for pricing of such wheeling services has become increasingly controversial with some utilities favoring the existing embedded cost allocation and other utilities proposing the use of a marginal cost method.

1.1.5 Fuel Market Volatility

Increasing uncertainty and volatility in fuel markets may increase the divergence in the prices at which utilities in Texas can purchase natural gas and other boiler fuels. This raises the possibility that coal or lignite generating capacity may be underutilized in the future and may result in a situation where one utility finds it more economical to purchase power from another utility facing lower fuel costs than to generate the power with its own higher priced fuels. Such purchases become feasible and attractive only if adequate transmission facilities to ship the power can be identified and utilized.

1.1.6 Health and Environmental Factors

In recent PUCT regulatory proceedings, in a lawsuit brought against Houston Lighting and Power (HL&P), and in COA public hearings, considerable public attention has been focused on the possibility of health and environmental impacts associated with transmission lines and rights-of-way located in urbanized or suburban areas. With inconclusive and often conflicting scientific information concerning these issues, the controversy surrounding them is expected to persist into the foreseeable future and could impact the future construction of transmission facilities.

1.2 Study Objectives

In recognition of the importance, complexity, and statewide implications of the issues discussed in Section 1.1, the following objectives were defined for this study:

- To determine whether greater energy efficiency may be obtained from existing generation and transmission capacity in Texas through enhanced system coordination and increased bulk power transactions.

- To determine whether enhanced coordination and increased bulk power transactions can help to reduce the requirements for new capacity additions.

- To determine whether a better matching of statewide capacity and load growth can be achieved through changes in the operation or configuration of the bulk power system.

- To determine whether utilities in Texas can take greater advantage of their production cost differentials through expanded bulk power transactions.

- To identify legal, technical, and environmental impediments which may be associated with enhanced interconnection of utilities in Texas.

- To identify operational, financial, and regulatory impediments which may be associated with increased transfers of existing and potential cogenerated power, as well as access to the transmission system.

- To examine operational, financial, and regulatory impacts of existing wheeling rules on utilities, cogenerators, and potential bulk power transactions.

- To estimate the likely impact of fuel price volatility, demand forecast uncertainty, seasonal fuel supply disruption, and power plant construction uncertainty on the State's electric power industry.

- To analyze the potential effects on bulk power transactions of transmission system limitations, alternative coordination arrangements, and alternative levels of cogeneration.

While the resources devoted to this project were not always adequate to address all of these objectives in a comprehensive manner, the results of the study represent significant progress toward quantification, understanding, and policy recommendations. Insofar as possible, topics which require extended or additional research have been identified in this report.

1.3 Methodology

In addressing the objectives identified above, this study investigated actions taken by other states, reviewed a number of existing studies, and analyzed a large volume of information provided by the State's utilities and cogenerators. Computer simulation techniques, using the Multi-Area Production Simulation with Megawatt Flow (MAPS/MWFLOW) program developed by General Electric Company, were used to analyze the operations of the ERCOT system.

Computer simulation is a widely accepted approach to system analysis in engineering and scientific communities. The utility industry currently uses simulation for reliability analysis, fuel budgeting, system planning, and many other applications. Such simulation is accomplished with the use of a model. A model is a combination of computer software (programs) and hardware (equipment) that mathematically mimics the behavior of the simulated object or process.

In a simulation model, relationships among components are defined with mathematical equations. However, mathematical relationships do not automatically translate to high precision. In the real world, such relationships can be extremely complex and "simplifications" have to be made. In some cases, simplifications are made because precise mathematical definitions are not possible. In other cases, they are made because of computing resource constraints.

In this study, several simplifications are made in the modeling process. It should be noted that MAPS/MWFLOW is one of the first modeling tools that combines a model for the transmission network and a model for electricity generation, and that the type of study undertaken in this project is relatively new to the utility industry. As a model, MAPS/MWFLOW has limitations due to the simplifications. Simplifications are necessary because of current computer technology and the development costs. Like any other models, MAPS/MWFLOW will continue to evolve to widen its applicability. Some characteristics or lack of features may prove undesirable and prompt the developer to make adjustments to the model.

A highly complex subject like the one undertaken here takes time and is subject to evolution, requiring several studies before definite final answers can be given. The environmental impacts of electromagnetic fields is another example of a subject that has been studied by different groups of experts for several decades. Studies are repeated by different groups of researchers who contribute a wide range of perspectives on the subject. Each time the answers are improved, the limitations are addressed, and some insight is provided. The subject of this study is no exception.

In this study, the ERCOT utilities are modeled as interconnected systems that permit generation and transmission resources to be shared. Given information on each generating unit and transmission line in the ERCOT system, MAPS/MWFLOW calculates the least-operating-cost strategy to meet the bihourly demand on the system for a selected study year. The program then reports the optimal pattern of bulk power transactions within the ERCOT system, the potential cost and energy savings which result from increased use of the transmission network, and the capability of the network to accommodate such transactions under a variety of alternative assumptions. A complete description of MAPS/MWFLOW and its operation can be found in Appendix A.

In December 1987, a draft final report on the results of the study was submitted to three external review committees. One of these committees represented the ERCOT utilities; the second represented cogenerators, small power producers, and large industrial customers; and the third represented a variety of consumer interest groups. A listing of the organizations and individuals participating in the review, a summary of the comments received at the meetings, and copies of their formal written comments can be found in Appendix G. The primary changes which resulted from this review are the correction of heat rate input data from TUEC, the addition of some 200 monitored lines in the transmission constraint set as identified by loadflow analysis by LCRA and COA, and the addition of reference cases which reflect converging natural gas prices as currently found in the Texas market. The study staff is very grateful to all of the individuals who participated in this detailed review and the constructive suggestions which were obtained and incorporated herein.

From a policy perspective, the conclusions of this study provide a general indication of whether it is economical or feasible to provide increased levels of coordination among Texas utilities, cogenerators, and potentially, out-of-state suppliers. The project's general perspective and its limited resources did not permit a detailed study at the utility planning level and is not intended to provide a statewide plan for the utilities. Actual system operations and planning remain the responsibility of the individual utilities in accordance with the appropriate policies and regulations of ERCOT or the PUCT.

In 1986, the total combined capacity of generating utilities for the State of Texas was 56,088 MW, with 45,407 MW (81%) located within ERCOT. In the version of MAPS/MWFLOW used for this study, seven of the State's largest utilities -- accounting for 43,379 MW (95%) of generating capacity within ERCOT, or 77% of the entire State --

are modeled explicitly. These utilities and their 1986 generating capacities are listed below:

COA	City of Austin	1,906 MW
LCRA	Lower Colorado River Authority	1,836 MW
CPSB	City Public Service Board of San Antonio	3,210 MW
TUEC	Texas Utilities Electric Company	17,804 MW
HL&P	Houston Lighting and Power Company	13,905 MW
CP&L	Central Power and Light Company	3,650 MW
WTU	West Texas Utilities Company	1,068 MW

In the model, CP&L and WTU are treated as a tight power pool where the generation resources are centrally managed by their parent holding company Central & Southwest Services, Inc. (C&SW). The non-ERCOT generating utilities in the State are not explicitly modeled, because they are not currently interconnected to the ERCOT system. Cogeneration capacity is explicitly represented in the model as generating units with predetermined availability within the host utilities.

1.4 Description of Scenarios

This is the first study to perform this type of short-term analysis of utility system operations in the State of Texas. The study concentrates on evaluating the potential for short-term benefits from bulk power transactions among the interconnected utilities in 1990 and 1995. For each forecast year two reference cases are developed -- one assuming a single-tiered natural gas market with diverging prices, and the other assuming a two-tiered natural gas market with converging prices. A historical representation of 1986 with assumptions similar to the reference cases is used as a benchmark for the relative comparison of the differing results of the reference cases. These cases represent the conditions where utilities attempt to exchange the maximum amount of energy to yield minimum overall operating costs.

To address future uncertainties and limitations of the model, several alternative scenarios are developed to analyze the impact of varying the uncertain parameters. It should be emphasized that the results from the reference cases are less meaningful by themselves than when they are used as a basis for comparison with the alternative cases. While fuel prices may fluctuate, the relative impact of their fluctuations is more likely to remain unchanged. When projections of demand and fuel prices are revised at any time in the future, it is quite likely that they will be different from those used in the study. But, by using the comparisons given in this report, estimates of the magnitude and direction of changes on potential transactions and savings can be derived.

The following list of scenarios reflects the specific cases which are examined in detail in Chapters 4 and 5:

- Reference Cases -- These scenarios examine the operation of the ERCOT utilities based on projections of data available in 1986 and 1987. Technical data on generating units and the transmission system were obtained from electric utilities. Demand forecasts were obtained from the participating utilities. Fuel cost projections for the diverging natural gas prices were developed by the project staff while the forecasts for the converging gas price case were submitted by the ERCOT utilities. For the operational mode referred to as "pooled", the ERCOT utilities are assumed to be fully coordinated in exchanging information and energy, but not necessarily dispatched from a central location.

- Transmission System Limitations -- This scenario models the impact of changing the constraints on the transmission system to include outage conditions by using a different model solution algorithm to incorporate the latest ERCOT transfer limits directly.

- Alternative Coordination Arrangements -- These scenarios show the results of coordinated maintenance scheduling among the utilities, and the effect of allowing only non-firm energy transfers to occur.

- Demand Forecast Uncertainties -- These scenarios examine the potential effects of future load requirements which are greater or less than the reference case forecasts for power and energy. The resulting effects on system reserve margins and the level of bulk power transactions are analyzed.

- Nuclear Power Uncertainties -- These scenarios consider the possible consequences of cancelling one unit of either the Comanche Peak or the South Texas Nuclear Project and its effect on the operation of the ERCOT system. Potential cost mitigation is calculated for both own-load and system coordination alternatives for the affected utilities.

- Alternative Fuel Prices -- These scenarios investigate the impact of variations in the price of boiler fuel on the operations of the ERCOT system and the individual utilities in the study. Particular attention is given to the role of natural gas as the incremental or "swing" fuel in the system.

- Alternative Levels of Cogeneration Activity -- These scenarios examine the impact of variations in the level of cogeneration, ranging from a 15% reduction in the expected level of cogeneration to a 15% increase in the expected level of cogeneration. The potential of cogenerated power to displace utility generation with other fuel types is examined under the alternative assumptions along with its relative efficiency and impact on the cost structure of the ERCOT utilities.

- Winter Fuel Supply Disruption -- This scenario, developed from the experience of the utilities during the prolonged freeze of the winter of 1983-84, considers the potential impact of the loss of generating units due to extremely severe weather. Such weather conditions could result in natural gas distribution problems or frozen coal and lignite stockpiles, and require affected utilities to burn fuel oil or import power from other ERCOT members.

- DC Interconnection to Adjacent Power Pools -- This scenario was originally proposed to define possible points of interconnection between ERCOT utilities and utilities which are members of adjacent reliability pools. At present, only one such DC interconnection exists between WTU and Public Service of Oklahoma (PSO) as members of the C&SW holding company. Because of complicated legal and institutional circumstances, a specific interconnection scenario could not be developed and no quantitative results are presented. An advisory opinion related to this issue from the PUCT General Counsel's office can be found in Appendix F.

1.5 Summary of Study Results

The following sections present an overview of the results obtained from the reference cases and the alternative scenarios described above. The monetary values used to describe annual savings are only for fuel and variable operating and maintenance costs. Capital and fixed costs are not included. Where percentages (%) are used to describe results, they are derived in comparison to the reference case results described in Section 1.5.1. Interested readers should also refer to the appropriate sections of Chapters 4 and 5 in order to fully understand the particular sets of assumptions which underlie the results.

It should be emphasized that interpretations of the results in this report should be made only in conjunction with the specific assumptions and limitations of the model. Time and resource constraints did not permit a fully detailed study of such complex subjects as system reliability or reactive power requirements, therefore all results are subject to further refinement using more appropriate analytical methods. This study is only a first step towards understanding the potential for and impacts of increasing the level of coordination within ERCOT. It should not be interpreted as criticism of existing operating policies, particularly because ERCOT has already implemented an energy broker system as an initial step in providing for more economical energy transfers.

1.5.1 Reference Case Results

As discussed in detail in Section 4.2, when the MAPS/MWFLOW model is run using the reference case input and assumptions, the results show a reasonable opportunity for the ERCOT utilities to engage in expanded bulk power transactions. For the years 1990 and 1995, assuming converging gas prices, the amounts of energy which could be exchanged in ERCOT under fully coordinated operations are 14.4 billion and 16.0 billion KWH, or 7.1% and 6.6% of total system energy, respectively. The corresponding annual savings would be $55.8 million and $108.1 million, or 1.3%, and 1.6% of system variable production costs. By assuming diverging gas prices, the amounts of energy which could be exchanged increase to 28.0 billion and 24.7 billion KWH, or 13.8% and 10.3% of total system energy, respectively, with corresponding annual savings of $247.2 million and $354.7 million, or 5.6%, and 4.7%. Under both gas price scenarios, the total BTU fuel consumption in each of the study years remains virtually constant when the model dispatches the system under the own-load and fully coordinated operations, although total fuel consumption increases over time.

1.5.2 Transmission System Limitations

This scenario uses the 1987 transfer limits calculated by ERCOT and a different solution algorithm for 1990, hence the results cannot be directly compared to the reference case. Under no-outage conditions, however, comparable results are obtained while the imposition of the outage conditions reduces total exchanges by 29% and annual savings by 27%. Applying these calculations to the reference case shows the upper limit on firm transactions to be 19.9 million KWH such that any additional transactions would need to be fully interruptible.

1.5.3 Alternative Coordination Arrangements

As discussed in detail in Section 5.2, the first scenario adds coordinated maintenance scheduling for the utilities. Assuming diverging gas prices, this change increases transactions by only 2.2% and annual savings by only 2.3%. The small magnitude of these numbers indicates that current maintenance scheduling of the ERCOT utilities is nearly optimal.

The second scenario is designed to simulate a non-firm-transactions-only arrangement, similar to the operation of an energy broker system, where each utility first commits its own units to satisfy its own load before engaging in purchases and sales. These constraints result in a 57% decrease in transactions to 12.0 billion KWH and a 67% decrease in annual savings to $82.4 million.

1.5.4 Demand Forecast Uncertainties

As discussed in detail in Section 5.3, these scenarios are designed to assess the impact of a range of alternative demand forecasts on the potential level of transactions and the utilities' demand/capacity balance in 1990 and 1995. Particular attention should be paid to the comparison of demand forecasts for utilities which have recently filed new forecasts that are considerably lower than the early 1986 forecasts. Unlike earlier versions of this report, those utility forecasts are now used to define the reference cases. In the low demand case, forecasts are reduced by 5% while in the high demand case, forecasts are increased by 5%. Because of the change in the reference case, the difference from low to high is therefore at a lower level.

In 1990, the low demand case causes utility reserve margins to rise above the reference case levels. These additional reserves result in a 4.3% decrease in transactions and a 5.3% reduction in annual savings. In the high demand case, transmission constraints limit the transactions increase to only 1.5% and the increase in savings to 2.5%.

In 1995, the low demand case shows a decrease in transactions of 6.1% and a 3.6% reduction in savings. In the high demand case, transactions increase by 7.6% and savings increase by 6.2%. The greater relative sensitivity of the 1995 results is attributable to a lower level of economic transactions which results in more available transmission capacity when the reference case assumptions are changed.

1.5.5 Nuclear Power Uncertainties

As discussed in detail in Section 5.4, these two scenarios examine the potential impact of extended construction or licensing delays which would result in the unavailability of one unit of either the Comanche Peak or the South Texas nuclear plants in 1990. In either case, total system operating costs rise under own-load operations, although only the respective owners of the projects are affected.

In the case of losing a Comanche Peak unit, with coordinated operations, the level of transactions increases as TUEC increases its imports because of tight capacity reserves. When compared to the parallel own-load case, annual savings are $284.2 million, thus providing a cushion of cost mitigation if the unit is not available.

In the case of losing a South Texas unit, with coordinated operations, the level of transactions decreases as the owners use more of their own excess capacity to meet their loads. When compared to the parallel own-load case, annual savings are $241.1 million, again providing a cushion of cost mitigation if the unit is not available.

1.5.6 Alternative Fuel Prices

As discussed in detail in Section 5.5, these scenarios examine the relationships between the level of transactions, annual savings, and natural gas prices. Because the converging gas price reference case is based on a uniformly low gas price for all of the utilities, only two cases are necessary to examine the effect of prices which are higher than those in the diverging gas price reference case. In both cases, the primary effect is to increase the substitution of other fuels for natural gas, with almost no change in total BTU requirements.

In 1990, with all gas prices 10% higher than those in the reference case, total system costs increase and, as expected, annual savings increase by 15.2%, while transactions actually decrease by 1%. This demonstrates that, above the reference case prices, increases in gas prices artificially inflate the savings, but cause no real change in system operations.

In 1995, the gas price is again assumed to be 10% higher than the reference case. The results are similar to the 1990 case with total system costs increasing, an 11.4% rise in annual savings, and virtually no change in the level of transactions.

1.5.7 Alternative Levels of Cogeneration Activity

As discussed in detail in Section 5.6, these scenarios estimate the impact on fuel usage, transactions, and annual savings for levels of cogenerated energy which are 15% lower and higher than shown in the reference case in 1990. Several cases which appeared in earlier versions have been dropped because they required highly implausible assumptions about the structure of the industry or the relative costs of utility supplied versus cogenerated electricity.

In the low cogeneration scenario, as expected, HL&P and TUEC (the only buyers) increase their use of gas, coal, and lignite resources by relatively small amounts to replace the loss of cogenerated energy. At the ERCOT system level, total BTU requirements increase by only 1.3%. Because of the small changes, transactions and savings change by a nearly negligible amount.

In the high cogeneration scenario, again as expected, HL&P and TUEC decrease their use of gas, coal, lignite, and nuclear resources by relatively small amounts. At the ERCOT system level, total BTU requirements decrease by only 1.3%, and the changes in transactions and savings are also nearly negligible.

Although the low and high scenarios understate the total fuel displacement because of the assumption of a cogeneration heat rate of 10,000 BTU/KWH, they can be used in combination to estimate the minimum amount of fuel displaced by the 3,135 MW of cogeneration expected in 1990. The total displacement would be 174.5 trillion BTU, with gas accounting for 143.1 trillion, coal for 23.9 trillion, and lignite for 7.5 trillion.

1.5.8 Winter Fuel Supply Disruption

As discussed in detail in Section 5.7, this scenario considers the implications of a prolonged period of freezing weather like the one which occurred in late December, 1983. During such a period, utilities may experience problems with frozen fuel sources such as stockpiles and pipelines, plant site fuel handling equipment, and fuel availability as a result in curtailments by natural gas suppliers. Since the 1983 event, affected utilities have implemented measures to prevent such problems or minimize their impacts on system operations. The ERCOT utilities now hold winter fuel oil inventories approximately six times as great as the total amount they had to burn in place of gas during the 1983 freeze. The reference case results for 1990 indicate that even with more than 9,000 MW of capacity out of service for scheduled maintenance, the ERCOT reserve margin under normal winter weather conditions is over 48% or nearly 13,600 MW. This capacity availability indicates that bulk power transactions provide a mechanism for supplying power to individual utilities experiencing increased demand levels or loss of generating units during severe winter weather conditions.

1.5.9 DC Interconnections to Adjacent Power Pools

As discussed in detail in Section 5.8, no quantitative results could be obtained for this scenario because of complicated legal, institutional, and technical issues beyond the scope of the study. Appendix F contains an advisory opinion from the PUCT General Counsel's office which addresses the legal complications involved in this multi-jurisdictional issue.

1.6 Qualitative Considerations

In addition to the quantitative results obtained from the study, there are two significant areas of qualitative consideration that have implications for the future of increased bulk power transactions. These areas concern the advantages of a strong transmission system and the existence of impediments to the development and utilization of the system.

1.6.1 Advantages of a Strong Transmission System

Historically, the ERCOT system has provided Texas with a very high level of reliability in the supply of electricity. Through the cooperative development of planning criteria and operating policies, the utilities which compose the membership of ERCOT have developed well-designed and well-engineered transmission facilities that provide a secure system for handling emergency situations arising from unexpected generator failures, adverse weather conditions, downed transmission lines, and the like. While the results of this study indicate that it is theoretically possible to increase the level of bulk power transactions, they do not adequately identify the practical limits of the transmission system particularly regarding system stability and reliability. In any case, the potential benefits must be weighed against the need to maintain or enhance ERCOT system reliability. To the extent that economically desirable transactions are sought by individual utilities, much detailed study and analysis will have to be performed before their implementation. It is likely that in some cases, particularly for firm transactions, additional facilities will be required to carry increased power flows, and the costs of their construction must be weighed against the potential benefits accruing to sellers, buyers, or wheelers. Continued cooperation between ERCOT and the PUCT should insure that system reliability is accorded the proper recognition in the transmission planning and certification process.

The development of a strong and reliable transmission system that recognizes the potential for economic power exchanges will provide a strong incentive for individual utilities to broaden their planning horizons to include more analysis of purchased power options. It will encourage those utilities with excess capacity to seek markets for their energy with other utilities which are facing deficiencies. As this process evolves, it will stimulate new levels of analysis which more fully account for the cost differences between utilities with markedly different load characteristics. Similarly, it will allow more inter-utility coordination of routine maintenance scheduling and may lead to a better seasonal use of existing capacity within the ERCOT system.

The existence of a good transmission system also has some longer term advantages as it complements the development of necessary generating capacity, whether utility-owned conventional plants or industrial cogeneration projects. In some cases, it may well be possible to use the transmission system as a substitute source of power and energy, and defer or cancel the need to build more capital intensive generating plants. Similarly, the strength of the system may allow utilities which are located far away from sources of cogenerated power to incorporate cogeneration into their capacity mix in lieu of building conventional plants.

1.6.2 Impediments to Bulk Power Transfers

Although there are many advantages associated with the development of bulk power transactions on a strong and reliable transmission system, there are also many impediments which may create difficulties or delays in implementation. One of these occurs because of organizational inertia in the industry and in regulatory institutions -- both of which have evolved with philosophies that are grounded in the application of earlier precedents. For the utilities this is often expressed in terms of engineering design standards, proven technologies, financial conservatism, and planning policies which necessarily recognize the long lead times associated with capital construction. For regulatory authorities, this is manifested in terms of applications of standard practice, reliance on earlier legal precedents, limited planning authority, and the need to conduct complex public deliberations to ensure that all relevant facts and positions are heard. The length of time involved in the decision-making process is often referred to as "regulatory lag." Texas Senate Bill 142, which became law in 1987, sets a maximum time limit of one year for the PUCT to act on applications for certification of transmission facilities. In the event that the application has not received a final disposition within one year, an aggrieved party may pursue relief in a State district court of competent jurisdiction. This requirement is expected to reduce the lag period in the future.

Another factor which may impinge on the systematic development of the transmission grid is the manner in which planning is now conducted by the individual utilities. Since there are no requirements for developing a statewide transmission plan, most utility plans are oriented toward short-term improvements in their transmission systems for the primary purpose of serving their own loads from their own generation resources. Although ERCOT plays an active role in examining the reliability effects of changes in the transmission system through loadflow and other forms of engineering analysis, little attention is given to the potential economic effects. Similarly, the PUCT has no specific legal authority to require statewide transmission planning; thus, applications for certification of new facilities usually proceed independently on a case-by-case basis.

Because of the emphasis given to individual development of facilities, most utilities are relatively unaware of the load forecasting and resource planning efforts of neighboring systems. In part, this is a result of some reluctance on the part of the utilities to be in a position of dependency which relies heavily on the resources of other systems or cogenerators. Some additional lack of coordination is prompted by each utility's desire to protect cost information which it may subsequently use to establish wheeling charges to be levied on adjacent systems who wish to engage in bulk power transactions. Wheeling rates and agreements may be subject to complicated and protracted negotiations among the utilities and with the PUCT which has adopted an embedded cost methodology for calculating wheeling rates.

A final area which has emerged in recent years is the uncertainty surrounding the environmental and potential health consequences associated with building and operating high-voltage facilities. In at least one case, following the certification and construction of a 345 KV line, lengthy civil litigation prevented a major utility from energizing the line and ultimately resulted in a partial re-routing while the case wound its way through the appellate process. More recently, a large municipal utility was forced to abandon plans for construction of two segments of 345 KV lines as a result of an organized lobbying effort by opponents who lived near the proposed lines. As discussed later in Chapter 6, this very sensitive issue continues to generate controversy and uncertainty within the scientific community, the utility industry, and regulatory authorities.

1.7 Conclusions

This is the first study to analyze the use of the bulk power transmission system in Texas. As such, it cannot be expected to provide definitive answers to all of the questions that are raised. On the contrary, in many areas the study raises additional questions which require further studies. Some of these areas are outlined in Section 1.8.2.

The results of this study provide a clear indication that more efficient use of the State's bulk power transmission system could lower the cost of generating electric power in Texas, better match the supply and demand for electricity in the State, and encourage greater efficiency in the use of the State's energy resources. Although the results in the study show the transmission network to be capable of accommodating a higher level of bulk power transactions, they do not adequately identify practical limitations involving system stability and reliability. Preliminary analyses made by some ERCOT utilities suggest that such level as reported in the reference cases with diverging gas prices may not be practical because it could cause serious reliability problems to the network. In order to recognize the full benefits while staying within the practical limit of the transmission network reinforcements of new lines and equipment upgrades are necessary.

In the reference cases and in many of the alternative scenarios, system operations under two theoretical extremes are quantitatively compared. In one extreme, each utility is assumed to serve the demand for electricity in its service area with its own generating capacity or capacity provided through existing or currently planned capacity contracts with neighboring utilities or cogenerators. In the other extreme, utilities are assumed to be fully coordinated and actively engaged in all economically feasible bulk power transactions in order to minimize the overall operating costs of the ERCOT system.

The difference in operating costs and fuel uses under these extremes represent the upper bound of savings that can be achieved from the bulk power transactions. The level to which this upper bound is limited is largely determined by the levels and differentials in natural gas prices paid by the ERCOT utilities. While the interconnected utilities in Texas are not currently operating at either of the two extremes, historical data indicate that their operations are closer to the own-load mode.

The brokerage system established in 1986 will be one mechanism for the interconnected utilities in the State to exchange power and reduce their operating costs. It is quite possible that with close coordination of system operation evolving through the brokerage system, the total savings in operating costs could approach the levels reported in this study.

The study itself does not emphasize any particular mechanisms for organizing the transactions. Instead it shows the upper boundary of potential savings when all possible transactions are made in an optimal fashion. The study also shows that every utility can obtain economic benefits from the optimal level of transactions.

The results indicate that significant cost savings could be realized through an increase in bulk power exchanges among the interconnected utilities in the ERCOT system. The reference cases assume that the utilities increase their operational coordination from completely independent operation to close coordination of their generation scheduling to allow bulk power exchanges which result in minimum systemwide generation costs. Under these assumptions with converging gas prices, annual savings of $55.8 million and $108.1 million in fuel and variable O&M costs could be realized in 1990 and 1995, respectively. These savings translate into approximately 1.5% of the variable components of annual operating costs. If natural gas prices rise rapidly and diverge, potential transactions increase and annual savings rise to $247.2 million and $354.7 million, respectively, or approximately 5%. Because the model considers only fuel and variable O&M costs, the estimated savings do not consider other operating cost components such as fixed O&M costs and start-up costs.

As a result of limitations in available resources, this study considers only the short-term benefits which could be realized from expanded bulk power transactions. Existing benefits resulting from present levels of economy transactions are subsumed in the calculated totals, and short-term costs such as incremental transmission losses or wheeling charges could not be included in the cost calculations. Despite these omissions, this report is an appropriate first step as part of a proposed multi-year study to address these and many other related issues. Indeed, this study has raised many new questions which can only be answered by additional research and detailed analysis.

This study has investigated the hypothesis that short-term benefits can be obtained from enhanced coordination among ERCOT members, and shows that the level of benefits is quite variable and dependent on the particular assumptions made about the future. Additional studies should address the complete short term cost/benefit question by investigating the potential costs of improving operations and coordination, as well as the allocative questions raised by the inclusion of wheeling charges.

In this study, the major factor driving the level of transactions is the relative levels of excess capacity among the utilities. Only those utilities with large amounts of available excess capacity become large exporters of power and energy. The fuel price differential among the utilities, however, is the major determinant of the monetary value of the savings attributable to the increased level of transactions. This can be easily seen by comparing the values shown for the two reference cases for each study year which are based on quite different forecasts of the structure of natural gas markets and prices.

In addition to the refinement of short-term considerations, potential long-term costs and benefits should be estimated and carefully analyzed in future research efforts. Theoretically, increased coordination through joint planning of the bulk power transmission system can use resources located in some utility systems to eliminate or defer the need for new generating capacity additions in others. If, however, the available resources are located outside of ERCOT, there are a number of technical, legal, and institutional questions which also have long-term consequences and which must be thoroughly investigated and understood before any attempt is made to proceed. At present, according to the PUCT General Counsel's office, such inter-ties could only occur if ordered by FERC under special conditions.

Within the ERCOT system, although existing and planned transmission facilities appear to have sufficient capability to handle the lower estimated levels of power and energy exchanges under normal operating conditions, their reliability may be compromised by the increased flows. In one alternative scenario, assuming the existence of outages of selected transmission lines, transactions are reduced by nearly one-third. If more detailed analyses are performed in the future and also indicate that such problems persist, some new lines will need to be built and some existing equipment will need to be upgraded to accommodate the increased level of transactions. Future research efforts, in cooperation with ERCOT and individual utilities, should be directed at identifying the particular regions and facilities where potential transmission problems may arise.

The potential need for the construction of additional or upgraded transmission facilities also raises questions about the possible health or environmental consequences of such projects. Despite extensive research, no consensus has been reached in the scientific community, or among State regulatory authorities, about the presence or absence of transmission-related public health problems which might require additional regulatory attention. The study concludes that the PUCT should continue to closely monitor developments in this area and develop an annual assessment based on emerging research. Similarly, the PUCT's environmental requirements are about average when compared to other states, and do not currently require modification.

Enhanced operational coordination in the ERCOT system would also increase the potential utilization of cogeneration located in the Gulf Coast area. As a result of much slower load growth, HL&P does not expect to contract for any additional capacity from cogenerators until at least 1995. However, to the extent that it is operationally feasible, other utilities with the need to obtain additional capacity and energy may well be able to take advantage of this relatively inexpensive source in the short-term. If future cogeneration facilities have adequate access to the transmission grid, all of the ERCOT utilities may want to include some cogeneration supply in their resource plans for the future.

With respect to the efficiency of energy usage in Texas, the study indicates that almost no change in total BTU's result from fully coordinated operations with diverging gas prices. With converging gas prices the BTU reductions are 0.75% and 0.37%, in 1990 and 1995, respectively. However, for natural gas, which is expected to become more scarce in the future, the respective savings for gas-fired generation owned by the ERCOT utilities are 6.6% and 3.2% with diverging gas prices, or 5.9% and 4.5% with converging gas prices. These reductions take place through the substitution of nuclear, coal, and lignite fuels for the relatively more expensive natural gas. Additional gas savings of 4.8% and 5.3% may be realized through the relative efficiency of cogeneration as compared to conventional gas-fired generation. These estimated fuel savings give another positive indication of the potential for a more efficient usage of the State's energy resources in the production and transmission of electricity within the ERCOT system.

1.8 Summary of Recommendations

Presented below are recommendations for policy changes and/or actions which will assist in the development of strategies to expand the level of bulk power transactions in the State. Also, several topics which require additional research are identified.

1.8.1 Policy Recommendations

Based on the results and conclusions of this study, the following actions are recommended for implementation by the utilities, ERCOT, and the PUCT:

- Individual utilities in the State, working cooperatively through ERCOT or other organizations, should take positive steps to investigate sources of available generating capacity located outside their own systems and, where economically beneficial to the ratepayers, include these sources in their resource planning process.

- Active and potential cogenerators and small power producers should take positive steps to insure that all utilities in the State are aware of the amount of capacity and energy which is, or may become, available for sale at competitive prices.

- Utilities and cogenerators should continue to define and refine more accurate methodologies for determining comparable costs for existing and proposed capacity and energy in the State.

- ERCOT, through its various committees, should provide a forum for the evaluation of transmission requirements for existing and potential capacity and energy transactions which includes economic as well as reliability considerations.

- ERCOT, in cooperation with its member utilities, should closely monitor the newly implemented brokerage system and the existing bulletin board system with the intent to improve the information available to potential buyers and sellers, and thereby facilitate power and energy transactions among the participants.

- The PUCT, in cooperation with individual utilities and ERCOT, should closely monitor and review the effects of the current wheeling regulations on existing and potential bulk power transactions.

- The PUCT should continue to obtain and evaluate information which characterizes the State's bulk power system and identify potential areas of coordination which will improve the efficiency of the use of the energy resources within the State.

- The PUCT should continue to identify the impediments to bulk power transactions among the State's utilities and, where possible, adopt policies which will ameliorate these problems, as is currently being done with a review and streamlining of transmission certification requirements.

- The PUCT and the State's utilities should closely monitor emerging research concerning possible health or environmental effects associated with transmission facilities and develop an annual assessment of the information along with any necessary recommendations for action.

- The PUCT should monitor the development of bulk power transactions among the State's utilities with respect to access to the transmission system and the potential for increased competition among buyers and sellers of wholesale power and energy.

1.8.2 Additional Research Topics

The PUCT, ERCOT, individual utilities, and cogenerators should conduct additional research into the following topics which are extensions of the scope of this study, or are issues which were raised by the study, itself:

- The short-term costs, including administrative requirements, associated with implementing various levels of coordination among the State's utilities, and particularly within the ERCOT system.
- The optimal and equitable allocation of potential savings for specific utilities engaging in expanded transactions, whether they are the buyer, seller, or wheeler.
- The identification and estimation of specific long-term costs and benefits which might be obtained as a result of avoiding or deferring the need to construct additional generating capacity.
- The long-term role of cogeneration as a supply resource in the State and the competitive impacts on the State's utilities.
- The respective roles of the utilities, ERCOT, and the PUCT for transmission system planning to provide enhanced opportunities for bulk power transactions.
- The detailed identification of components of the transmission system which may need to be strengthened in order to retain ERCOT's excellent reliability at increased levels of transactions.
- The impact of wheeling charges and incremental line losses on the benefits and costs of bulk power transactions and their effects on the efficient use of energy.
- The potential impacts of interconnecting ERCOT to adjacent power pools or non-ERCOT utilities and the impact on efficient energy utilization.
- The potential impacts of increased bulk power transactions, their costs, and their savings on individual utilities and ultimately, on the residential, commercial, and industrial electricity consumers and ratepayers of Texas.

1.9 Report Organization

This report is organized into eight chapters plus seven technical appendices. Chapter 1, which serves as both an introduction and executive summary, presents an overview of the issues, objectives, methodology, scenarios, results, and conclusions of the study. Chapter 2 describes the economic theory underlying the analysis in the context of the electric industry, the role of uncertainty, and the role of competition. It also contains reviews of several previous studies of bulk power transactions, power pooling, and coordination of utility operations. Chapter 3 describes the operation and configuration of the electric power industry in Texas including information on generation capacity, peak demand forecasts, resource expansion plans, cogeneration, the transmission system, and fuel prices. Chapter 4 presents the underlying assumptions, analysis, and results of the reference case scenarios for the years 1986, 1990, and 1995. Chapter 5 presents the underlying assumptions, analysis, and results of a wide variety of alternative scenarios which test the sensitivity of the model to changes in key parameters. Chapter 6 discusses some of the background and literature about health and environmental issues, and presents the results of a survey of other states' regulatory policies concerning these matters. Chapter 7 reviews several studies of non-technical impediments to power transfers and their applicability to recent experience in Texas. Chapter 8 presents a summary of the study, suggests policy recommendations, and identifies several topics which require additional research.

Appendices A, B, C, D, E, F, and G, which appear in separate volumes, contain detailed model descriptions, input data, simulation output, survey results, and other extensive background material which document the methodology and analysis for the entire study.

Chapter 2

Bulk Power Transactions: Economic Theory and Review of Previous Studies

This chapter provides a general discussion of the underlying theoretical basis for the analysis of bulk power transactions. Economic theory and analysis are often used for decision support in many contemporary industry and regulatory settings. This study, however, recognizes the limitations of simple translations of theoretical applications obtained from other industrial settings and employs them cautiously. Similarly, the utility industry in Texas, when compared to other geographical regions of the nation, has many unique qualities which must be specifically characterized. Thus, particular attention is given not only to the uniqueness of this industrial setting but also to special considerations of current and expected conditions in the State.

The first section of the chapter deals with the application of economic theory to the electric utility industry. The next section discusses the unique structure of the electric power industry in general, and in Texas in particular. Uncertainty, as it pertains to the electric power industry, is then discussed, followed by a discussion of the role of competition in the market for electric power. Finally, five studies dealing with power pooling and operational coordination released since 1975 are briefly discussed.

2.1 Application of Economic Theory

Economic theory, as applied to the electric utility industry, is generally concerned with economic efficiency. Economic efficiency has two principal dimensions: the cost of supplying electricity and the prices that electricity consumers are charged. This study focuses primarily on the potential for supply-side efficiency and does not address the demand-side issues. Theoretically, cost savings obtained through increased supply-side efficiency would be reflected in the utilities' costs of service and, ultimately, in the price of electricity.

From an economic perspective, supply-side efficiency could reach its maximum potential when the supply system can satisfy the total demand requirements at the minimum cost among all other potential supply options. The goal to minimize the cost can be divided into long-term and short-term goals. The long-term goal involves resource planning to yield optimum supply level and fuel mix. The short-term goal involves scheduling the utilization of existing resources to minimize operating costs. This study is concern with the short-term goal.

From the long-term perspective, if a utility has more generation resources than it requires to meet demand, consumers may be forced to pay for these unused resources. On the other hand, if the utility does not have adequate generation resources, a portion of the demand will not be met. The cost associated with this supply deficiency is very difficult to measure but is considered to be very high for many customers.[1] Taking this cost of unserved demand into consideration, it is generally accepted that cost minimization cannot be achieved unless the utility can meet all the noninterruptible demand.

Theoretically, total cost is minimized when the generation resources can meet the demand without any excess, provided that the capacity mix is "optimum." An optimum capacity mix is the combination of different generating units that result in minimum operating cost for a given range of demand fluctuation in a given period of time.

From the short-term perspective, the utility can minimize total operating cost by applying the principle of "equimarginal" or "equal incremental cost." Under this principle, total

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[1] **The Value of Service Reliability to Consumers**, EPRI EA-4494, May, 1986.

operating cost is minimized when every generating unit in the system operates at the same marginal cost, given that the sum generation from all units equals the total generation requirements. The marginal cost for a generating unit is defined as the increase in costs associated with meeting the next incremental demand. The marginal cost is a nonlinear function of power output (MW). Equal marginal costs represent a state of the system where no further adjustment can be made to reduce the total operating cost at that demand level. To demonstrate this principle, one can assume a utility with three generating units, A, B, and C, operating at the marginal costs of x, y, and z $/MWH, respectively. A further assumption can be made that x is greater than y, and y is greater than z. If the output from unit A is reduced by 1 MWH and the output from unit C is increased by 1 MWH, the total operating cost will be reduced by the difference between z and x. A similar adjustment can be made to the A-B and B-C pairs to further reduce the operating cost. This illustrates that if units in the system operate at different marginal costs, an adjustment can always be made to the system to reduce the total operating cost. It is clear that once x, y, and z are equal, no adjustment can be made to the generation scheduling that will result in cost reduction.

The equalization of marginal costs is only an ideal condition which must be modified when other factors are considered. For example, the marginal cost function of a base load unit has a much lower range than that of a peaking unit. It is not likely that a base load unit will be operating at the same marginal cost as a peaking unit without violating the capacity limit. Therefore, the capacity limit is a constraint that must be imposed on the generation scheduling. Another factor is the transmission system which can affect the operation in two ways. First, losses occur when power flows through transmission lines. For the equimarginal cost principle to hold, the line loss component must be included as part of the marginal cost. Second, the transmission system may have limitations that prevent some units in the system from being utilized in the most economical fashion. In the past, when utility systems were small, the effects of transmission were usually neglected since transmission networks had usually had adequate capability to deliver electricity.

With the complexity of modern power systems, the transmission system is becoming an important element in total system operation. The transmission network, which was formerly regarded as merely a means to deliver electricity to load centers, is now recognized as a component of resource planning and is used to assure that available generating resources will be utilized at their full economic potential. Systems that were once isolated are now interconnected forming a single, sizable network. Choices have to be made on how the interconnection should be made, given budget constraints. The significance of the transmission system can no longer be neglected. In order to meet the demand, adequate transmission capability is required in addition to adequate generating capability. A weak transmission system can limit the use of economical resources and, in the worst case, cause a curtailment in electricity supply which can be very costly to society.

2.2 Structure of the Electric Power Industry

Unlike other industries, the goods produced by the electric power industry do not possess physical mass. Its existence can only be felt but not touched. Yet the product is vital to everyday life and the economy. Unlike other kinds of goods that can be packaged and transported by conventional means, electricity must be delivered through wires. A producer of electricity cannot necessarily direct the output to a particular location. Once electricity is produced, it will travel through the interconnected transmission and distribution lines. This means that the electricity which supplies a certain light bulb comes virtually from all active generating stations that are connected to the transmission grid.

The need for transmission and distribution lines to deliver electricity usually makes it extremely inefficient to have more than one utility serve a given area. Therefore, the industry becomes monopolistic and is required to operate under regulations. While municipally-owned utilities are generally self-regulated, investor-owned utilities are regulated by government agencies. The purpose of regulation is to insure that the utilities provide acceptable service while given the opportunity to earn a fair return on their investment. The major part of a utility's investment is composed of generating stations and transmission and distribution equipment. While the investment is usually large, the risk is usually low compared to other industries.

From the operational perspective, the industry is comprised of three distinct but dependent segments: generation, transmission, and distribution. As the name implies, the generation segment is comprised of power stations that produce electricity. The function of both transmission and distribution segments is to transport electricity, but the two differ in the way they carry electricity and in technical designs The transmission system is designed to carry a large amount of power from generating sources to substations located close to the demand center. Connections are also made between generating stations to reinforce the network. The distribution system carries electricity from the substations to the end-use customers.

The transmission network is usually comprised of power lines of 69 KV and above while the distribution network is comprised of lines from less than 69 KV to 110 volts, the voltage level used in a typical residential dwelling. The higher voltages used by a transmission system are designed to carry large amounts of power with minimum losses.

The characteristics of the distribution system are dictated mostly by the dispersion of local loads. The planning process of distribution is almost independent from generation and transmission planning. The generation and transmission systems, however, are related. The more complex the system, the more closely related the two are. The sole purpose of the transmission system is to reliably and economically deliver electricity from the generation sources to the distribution network. Transmission planning must be implemented in such a way as to support generation planning.

2.3 Uncertainty

Electric utilities have an obligation to provide an adequate supply of electricity at the lowest possible cost, although elements of uncertainty can make this objective difficult to achieve. Electric utilities must deal with uncertainty in both day-to-day operation and long-term planning.

In daily operation, mechanical problems can develop in any generating unit which force it to be shut down. An accident can happen to a component of the transmission network such as a transformer which puts it out of service. This implies that a utility must have "reserve resources" to make sure that such events will not curtail the delivery of electricity. For generation planning, a utility needs to have capacity exceeding peak demand to make up for an unexpected loss of generation. For transmission planning, the network must be strong enough to still handle the power flow even though some lines are disconnected. At the same time, the utility is not permitted to build any generating stations or transmission lines that it does not really need.

Uncertainty in demand growth makes it extremely difficult, if not impossible, to have just enough resources to meet demand. Construction of a new generating station takes anywhere from five to as long as fifteen years to complete. Any commitment to the construction of a new facility, therefore, must be made several years in advance. Uncertainty in demand may cause some utilities to have excess capacity and others to experience supply deficiencies.

Other types of uncertainty include those associated with fuel markets, construction delays, and cost overruns. Because system planning has several years' lead time, the element of uncertainty may result in a plan which fails to minimize costs. This is because changes in affecting parameters such as demand and fuel prices can drastically affect the demand/supply balance and alter the optimum condition for capacity mix.

In a variety of instances, the existence of uncertainty may motivate a greater degree of coordination among the interconnected utilities. For example, a common type of uncertainty that system planners must recognize is that associated with daily and seasonal load fluctuations. A coordination that permits capacity and reserve requirements to be shared among the interconnected utilities may result in greater economic efficiency. This may be particularly true for interconnected systems which serve large numbers of diverse customers.

System interconnection can help the utilities deal with uncertainties. Interconnections effectively increase the size of the system, thus, reducing the relative impacts of uncertainties. The transmission system, the only means of interconnection, plays a vital role in mitigating the impacts of uncertainties. A strong transmission network can reduce demand/supply imbalances as well as fuel price differentials.

2.4 Competition

From a purely economic standpoint, an increase in competition may result in greater system efficiency. However, the current conditions within which the electric power industry operates permit only limited types of competition. One of these is the competition for industrial customers. In conjunction with recruitment and incentives offered by state and local governments, utilities often compete with other states for new industrial customers. They also may compete with each other for industries within the state. For many industrial firms, electricity costs represent a relatively large portion of total manufacturing costs. These firms are likely to locate where these costs are lowest. Some of the utilities may even offer special rates to encourage these customers to locate within their service areas.

In addition, some utilities are striving to discourage large industrial customers from leaving the system to produce their own electricity as a result of rate increases. Loss of such a customer will cause the rate base to be spread over a smaller customer base, thereby raising rates for remaining customers and causing a "death spiral" to gather momentum.

Competition may also exist among generating utilities to sell power to nongenerating utilities. Traditionally, these nongenerating utilities have contracted to purchase power only from the generating utility serving the area in which they are located. If increased access to the bulk power transmission system is allowed, more competition can occur as old contracts expire or are renegotiated.

A key element of the forms of competition described above is that each may be considered a sub-category or proxy for competition for bulk power transfers. For the most part, the competition referenced here is at the wholesale level, although industrial self-generation may also be thought of as a retail sale displacement. This type of enhanced competition at the generation level requires accessibility and sufficient capacity of the transmission network.

2.5 Previous Studies

During the past decade a variety of studies, similar in nature to the PUCT project, have been conducted. The following discussion briefly presents examples of these works and the conclusions drawn from them. In general, these studies have analyzed the changing nature of ownership, financing, planning, and operation of electric utilities in part or portions of the U.S. power grid system. These studies have thus dealt with such concepts as rate structures, efficiencies in regional transmission of bulk power, financing of new generation facilities, system reliability, and competition. While this study addresses many similar concepts, there are significant differences in the methodologies employed as well as project scope. These differences may largely be attributed to the increase in computational capability which now permits the management of large amounts of data.

The first three studies discussed are national in scope and not specifically directed to the ERCOT system. The first is the **National Power Grid Study** performed by the Department of Energy (DOE) in 1980. The second is another 1980 DOE study, **Power Pooling: Issues and Approaches.** The third is a 1981 FERC study entitled **Power Pooling in the United States.** Additional studies that deal specifically with wheeling and impediments to bulk power transfers are cited in Chapter 7.

Finally, two separate studies performed on the Central and South West system (C&SW) are briefly discussed. Both of these studies were designed to capture the technical and economic aspects of alternative generation and transmission plans for interconnecting the four operating companies of the C&SW system, two of which (CP&L and WTU) are ERCOT utilities while the other two (Southwestern Electric Power Company (SWEPCO) and Public Service of Oklahoma (PSO)) belong to the Southwest Power Pool (SPP).

2.5.1 National Studies

The national studies resulted largely because of dramatic increases in energy prices in the early part of the 1970s and a nationwide recognition that the future development of the nation's bulk power system including transmission facilities had become very controversial issues. Because of the large financial commitments, substantial risks, and the burgeoning regulatory climate, the studies discussed below were designed to investigate whether or not opportunities might exist, on a national level, to make more efficient use of the nation's existing and future resources dedicated to the production, transmission, and distribution of power.

2.5.1.1 <u>National Power Grid Study</u> by the U.S. Department of Energy (1980)

In 1977, U.S. Senate Bill 1991 and House Bill 8793 were both introduced to the 95th Congress to begin establishing a national power grid policy. Then DOE Secretary James Schlesinger and President Carter were also committed to such an undertaking. One result of these efforts was the **National Power Grid Study** that was published in 1980. The study produced many interesting recommendations, some of which are the following:

1. The structure of the nation's electric power industry should be maintained. Additional coordination and integration could be achieved without sweeping institutional rearrangements.

2. In certain geographical areas a high degree of interconnection, coordination, and integration already exists while, simultaneously, there are areas of the U.S. where opposite conditions exist. Where the latter may be identified, the potential for greater integration should be explored.

3. A multi-state or regional approach to state regulation of utilities should be pursued. Regulatory agencies with adjoining jurisdictions which can or do comprise a power pool should initiate steps to permit them to address issues of joint interest.

4. Joint planning and operations should be encouraged.

5. Access to unused or underutilized transmission capacity should be assured where technically feasible.

6. The analytical capabilities of regulatory agencies should be enhanced and an accessible databank should be established.

7. The desirability of interconnecting ERCOT with the Eastern system should be investigated.

Clearly, many of the recommendations suggested in this earlier study are also areas of concern for Texas ratepayers. In many respects the PUCT project may be thought of as an extension of the National Power Grid Study.

2.5.1.2 Power Pooling: Issues and Approaches by the U.S. Department of Energy (1980)

This study which began in 1978 was conducted by Resource Planning Associates, Inc. of Cambridge, Massachusetts under contract with the Department of Energy. The primary objectives of the study were to investigate the use of power pooling to stabilize and possibly lower utility operating and capital costs and lessen national dependence on imported oil. The contract called for a comparative analysis of the New England Power Pool (NEPOOL), the New York Power Pool (NYPP), the Pennsylvania-New Jersey-Maryland Interconnection (PJM) and the Florida Electric Power Coordinating Group (FCG). While the other three were well-established systems, FCG had just begun to operate as a pool.

The study looked at various aspects of pooling operations among these four pools and identified issues faced by the pool members. According to the report, two fundamental issues are the obligation of each member to provide generation and transmission facilities to the pool and the right of each member to access those facilities. The nature of each of these issues varies depending on the objectives of individual utilities, but is usually formed around the economic and reliability benefits of pooling and the enhancement or preservation of the market position of the firm. These issues are generally resolved voluntarily among involved utilities; however, the resulting agreements must be approved by FERC.

Another issue is the coordination of operations which is very important in achieving the fundamental goals of power pooling. These goals are reduced operating costs, increased reliability, and improved operating efficiency. In the short term, well-coordinated operations can lead to substantial savings in fuel costs, while in the long run, they can lead to more effective capacity expansion planning that provides economic benefits to the entire pool. According to the study, in 1978 the intrapool energy exchanges saved FCG $16 million, NEPOOL $30 million, NYPP $60 million, and PJM $200 million.

The third and final issue mentioned in the report is pricing of transactions. An appropriate pricing procedure is the most critical factor in the early stage of power pooling and must be designed to allow an equitable distribution of costs and benefits among all pool members. Trade-offs must be made between simplicity and accuracy. Complex procedures may yield more accuracy but incur costs that may be high enough to offset the benefits. Factors affecting the pricing policy are unique for each pool but usually include the frequency of transactions, types of transactions, and system configurations; however, for the four pools in the study, similar pricing methods are adopted for similar transactions. In general, the greater the number and types of transactions, the more complex the pricing procedures become.

As a result of reviewing the operations of the four power pools, the study suggests that the formation of a power pool should evolve from simple transactions without formal agreement ultimately into fully centralized dispatch and unit commitment. The first step is to establish an energy broker system which can be achieved in a relatively short time if adequate transmission facilities are available. At this stage, pricing issues are not overly complex and the required investment in the facilities is small. Within this stage, member utilities can lay the groundwork for increasing coordination which involves an increase in the centralization of dispatching functions. Two forms of centralization are a full integration with a single designated dispatch center that has control over all the generating units, and a coordinating central dispatch center that provides detailed schedules to pool members while individual members still have full control over their own systems. As evolution progresses within this stage, a formal maintenance scheduling policy should be adopted and coordination of unit commitment should be initiated. Increased operation coordination at this stage requires more investment and commitment. The final stage of a fully integrated power pool is totally centralized unit commitment with the member utilities operating as a single system and coordination extending into long-term planning as well.

2.5.1.3 Power Pooling in The United States by The Federal Energy Regulatory Commission (1981)

According to the Public Utility Regulatory Policies Act (PURPA) passed in 1978, FERC is required to "study the opportunities for (A) conservation of energy, (B) optimization in the efficiency of the use of facilities and resources, and (C) increased reliability, through pooling arrangements." The 1981 study is a result of these requirements and identifies seventeen major power pools existing in 1980 with a combined generating capacity of over 320,000 megawatts -- more than 58 percent of total capacity in the contiguous United States. Four of the seventeen operated as "tight" power pools where the members jointly operated the systems as a single entity, while eight operated as "loose" pools. Five, including one in Texas, were holding company pools. In Texas, the Texas Utilities Electric Company pool consisted of three members: Dallas Power & Light, Texas Power & Light, and Texas Electric Service. (These companies were merged in 1984 and now operate as a single entity.)

Most of the power pools were formed during the 1950s and 1960s so there was essentially no increase in the number of power pools during the 1970s. Among the reasons cited in the report were slow growth in demand, smaller benefits gained in forming new pools, provision of coordination through the regional Reliability Councils, and joint ownership of generating facilities. The report also mentions that, in the recent past, several state commissions showed interest in holding down electricity rates through increased coordination.

In addition to a general review of power pooling, the FERC study also contains a review of operations in different regions. One chapter in the report is devoted entirely to systems in ERCOT. In 1967, nine major utilities in Texas signed a coordination agreement to form the Texas Interconnected System(TIS) -- mainly to insure the maximum reliability of operations. In the past, utilities in Texas used natural gas as their primary fuel. Thus with similar capacity mixes, production costs were similar throughout the state and provided little basis for energy exchange. The need to replace natural gas with alternative fuels like coal and nuclear were expected to widen the differential in production costs and increase the potential benefits of power interchange.

2.5.2 ERCOT Studies

As discussed in more detail in Chapter 5, ERCOT is interconnected to the Southwest Power Pool through a DC tie between two Central & Southwest (C&SW) companies, WTU and PSO. As part of the process to determine the efficacy of the C&SW status, two independent studies were performed. The first study presented below was commissioned by C&SW, while the second was commissioned by HL&P. Given that these two utilities had opposite objectives in mind, it is not surprising that the studies produced differing results.

2.5.2.1 <u>Expansion Study of the Central & South West Corporation Electric Power Sytem</u> by Power Technologies, Inc. (November 14, 1975).

Power Technologies, Inc. (PTI), was contracted in the early 1970s by the Central & South West Corporation (C&SW) to examine the general technical feasibility and economics of the future expansion of the bulk power system of the C&SW. This particular study was triggered by questions raised before the Security and Exchange Commission (SEC) involving the C&SW operating pattern. Alteration of operating patterns of the entire ERCOT and SPP regions was not considered. Analysis was instead limited to considering the potential effects of changing operating patterns only on the C&SW customers. The PTI study was not intended to offer detailed system representation. According to the report:

> The results of the 20-year expansion studies indicate that there are long-run economies available by adopting a pattern of complete synchronous operation for the C&SW companies. The savings in revenue requirements are primarily due to the operating economies that are potentially available by using an economic dispatch which considers the consolidated load of all of the C&SW operating areas so that the larger, more efficient fossil fired base load units will generate a larger percentage of the energy required than they would serving individual company loads and, therefore, will displace the higher cost units.

The present PUCT study considers a situation similar to that which PTI examined. The primary difference is that the current study puts greater emphasis on total systemwide efficiencies than on capturing impacts that might accrue to a specific group of utilities.

2.5.2.2 <u>Generation and Transmission Planning Study of the Electric Facilities of the Electric Reliability Council of Texas</u> by Stagg Systems, Inc.(December 1, 1977)

Two years after the PTI results were published, HL&P contracted with Stagg Systems, Inc. to perform a similar type of study, but with a slightly different scope. As an alternative, this study suggested an analysis which assumed that CP&L and the southern part of WTU operated as part of ERCOT, and that ERCOT and the SPP did not operate interconnected. The ultimate objective was to compare the costs of this expansion plan with those found in the PTI study. Under these assumptions, the study results concluded that greater economic benefits accrued to customers of CP&L and the southern part of WTU by their not being interconnected to the SPP.

One shortcoming of both the PTI and the Stagg study was in the representation of the remainder of ERCOT. In particular, a host of simplifying assumptions regarding generation and transmission expansion plans and fuel price forecasts of the other ERCOT utilities were employed to generate the results. No effort was made in either study to develop least-cost results from a systemwide (either ERCOT or SPP) perspective. The current PUCT study examines many objectives which are substantially more representative of the entire ERCOT interconnected system than those offered in previous studies.

2.6 Summary and Conclusions

Although the electric power industry has many unique features, nationally and in Texas, economic theory provides a starting point for analysis. Despite the presence of a variety of uncertainties regarding future development of generation and transmission facilities, large scale computer models can be used to simulate the bulk power system under different sets of assumptions

Traditionally, electric utilities have been characterized as natural monopolies; but more recent events have stimulated several different types of competition within the industry. Since 1975, several studies of bulk power facilities and operations have addressed the issues of power pooling and transmission system access. Increased emphasis on both of these issues tends to promote competition and produce a more efficient and less costly utilization of resources devoted to electric energy production.

Chapter 3
Configuration of the Electric Power Industry in Texas

This chapter provides background information on all the major generating utilities in Texas as well as descriptions of the cogeneration market, the transmission system, and fuel markets. Emphasis is placed on the seven largest generating utilities in the Electric Reliability Council of Texas (ERCOT), since only they are explicitly analyzed using the PUCT MAPS/MWFLOW model. Isolation of the ERCOT interconnected system from the rest of the national power grid and the limitations of the MAPS/MWFLOW model prohibit the explicit modelling of non-ERCOT Texas utilities.

Note that demand and capacity projections used in the study differ from those presented in this Chapter. While the discussion in this chapter relies on the 1986 release of the PUCT's **Long-Term Electric Peak Demand and Capacity Resource**, the study uses more recent projections supplied by the utilities.

3.1 Projected Utility Demand

The PUCT's biennial forecast, **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1986**, presents projections of demand for each of the major utilities in Texas. This section relies on the forecasts provided in that document.

Under this forecast, growth in the peak demand and consumption of electricity in Texas may continue to exceed national averages over the next ten years, but is expected to be significantly slower than in the past. Electricity demand growth is expected to be geographically uneven, with higher growth rates anticipated for Central Texas and lower growth rates for East Texas and the El Paso area. In general, the Commission staff's independent electricity demand projections for 11 of the largest utilities in the State are slightly lower than utility-developed forecasts of the same period. The forecasts are presented in Tables 3.1-1 and 3.1-2.

For the 11 largest generating utilities in Texas, a 3.0 percent average annual growth rate is forecast for peak demand (including interruptible load) from 1985 to 1995. The Texas component of the peak demand for these utilities is expected to grow at a rate of 3.2 percent. These projections are prior to adjustments for the impact of conservation and load management programs, and have not been adjusted for load diversity. The forecasts indicate a further slowdown from the rapid growth rates experienced in Texas in the past. From 1950 to 1970, peak demand in Texas increased at a relatively stable 10 percent average annual rate. From 1975 to 1985, however, peak demand growth in Texas slowed to a rate of approximately 5 percent.

The further reduction in electric peak demand growth rates expected for the next ten years largely reflects an anticipated slowdown in the State's economy subsequent to the dramatic expansion experienced in the 1970s. Lower rates of population and economic growth are responsible for the reduction in electric power demand growth.

The staff forecasts are significantly lower than the peak load projections developed by two utilities, El Paso Electric Company (EPEC) and Central Power and Light (CP&L). Peak demand forecasts developed by the staff and these two companies differ by more than 10 percent in 1995, the final year of the forecast horizon. Many of the State's electric power producers are currently revising their demand projections downward in light of recent economic conditions in Texas and passage of the National Appliance Energy Conservation Act of 1987.

Growth in electricity demand is expected to be strongest in Central Texas, which is served by the Lower Colorado River Authority (LCRA), the City of Austin (COA), and

TABLE 3.1-1

PUCT Staff Recommended Peak Demand Forecasts: Total Company Basis (MW)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	Average Annual Growth
TUEC	15,898	16,156	16,771	17,489	18,155	18,715	19,281	19,943	20,587	21,281	22,052	3.33
HL&P	11,075	11,380	11,895	12,033	11,902	11,684	11,746	12,192	12,869	13,661	14,610	2.81
CP&L	3,022	3,185	3,188	3,072	3,124	3,217	3,316	3,423	3,529	3,636	3,747	2.17
GSU	5,139	5,096	5,106	4,962	5,118	4,980	5,057	5,171	5,306	5,452	5,601	0.86
CPSB	2,350	2,450	2,529	2,616	2,712	2,811	2,915	3,018	3,123	3,239	3,358	3.63
SPS	3,005	2,922	3,002	3,076	3,149	3,226	3,300	3,380	3,463	3,548	3,634	1.92
SWEPCO	2,943	3,119	3,142	3,184	3,171	3,320	3,433	3,566	3,688	3,821	3,972	3.04
LCRA	1,434	1,660	1,748	1,842	1,925	2,034	2,168	2,322	2,497	2,689	2,903	7.31
WTU	1,089	1,214	1,228	1,234	1,261	1,296	1,338	1,384	1,428	1,471	1,514	3.35
EPEC	898	934	963	952	967	988	1,017	954	988	993	1,023	1.31
COA	1,320	1,384	1,464	1,542	1,619	1,696	1,773	1,852	1,933	2,014	2,098	4.74
TOTAL	48,173	49,500	51,036	52,002	53,167	53,967	55,344	57,205	59,411	61,805	64,512	2.96

Notes:
1) Projections include interruptible load.
2) For SPS, SWEPCO, EPEC, and GSU, data is presented on a total system basis.
3) No adjustment has been made for load diversity.

TABLE 3.1-2

PUCT Staff Recommended Peak Demand Forecasts: Texas Only Basis
(MW)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	Average Annual Growth
TUEC	15,898	16,156	16,771	17,489	18,155	18,715	19,281	19,943	20,587	21,281	22,052	3.33
HL&P	11,075	11,380	11,895	12,033	11,902	11,684	11,746	12,192	12,869	13,661	14,610	2.81
CP&L	3,022	3,185	3,188	3,072	3,124	3,217	3,316	3,423	3,529	3,636	3,747	2.17
GSU	2,352	2,452	2,481	2,507	2,713	2,585	2,627	2,675	2,727	2,781	2,834	1.88
CPSB	2,350	2,450	2,529	2,616	2,712	2,811	2,915	3,018	3,123	3,239	3,358	3.63
SPS	2,164	2,104	2,162	2,215	2,268	2,323	2,376	2,433	2,493	2,555	2,617	1.92
SWEPCO	1,442	1,528	1,539	1,560	1,554	1,627	1,682	1,747	1,807	1,872	1,947	3.05
LCRA	1,434	1,660	1,748	1,842	1,925	2,034	2,168	2,322	2,497	2,689	2,903	7.31
WTU	1,089	1,214	1,228	1,234	1,261	1,296	1,338	1,384	1,428	1,471	1,514	3.35
EPEC	614	602	599	587	584	593	610	631	653	676	700	1.32
COA	1,320	1,384	1,464	1,542	1,619	1,696	1,773	1,852	1,933	2,014	2,098	4.74
TOTAL	42,760	44,114	45,604	46,697	47,814	48,581	49,832	51,622	53,645	55,875	58,381	3.16

Notes:
1) Projections include interruptible load.
2) For SPS, SWEPCO, EPEC, and GSU, data is presented on a Texas-Only system basis.
3) For SPS 72% of peak is assumed to occur in Texas.
4) For SWEPCO 49% of peak is assumed to occur in Texas.
5) No adjustment has been made for load diversity.

the City Public Service Board of San Antonio (CPSB). For each of these utilities, average annual growth in peak demand is expected to exceed 3.5 percent through 1995. In East Texas, slow electricity demand growth is anticipated for Gulf States Utilities (GSU), which serves the Beaumont area and portions of Louisiana. Slow demand growth is also anticipated in far West Texas, served by EPEC. Both GSU and EPEC are involved in expensive nuclear power plant construction projects which will result in higher electric rates and downward pressure on electrical energy demand from each utility's ratepayers. Relatively sluggish economic growth is also expected for the areas served by these utilities which will further suppress demand growth.

Future industrial cogeneration activity remains a key uncertainty for the demand projections developed for the utilities serving the industrial Gulf Coast, namely Houston Lighting and Power (HL&P), CP&L, and GSU. Low prices associated with the current natural gas surplus make combined cycle cogeneration technology an attractive source of process heat and an electric power supply alternative for some large industrial customers. These industrial customers could sell the electric power from these projects at competitive prices or use the power to displace their own electric load requirements.

3.2 Utility Capacity Resources

The capacity resource forecasts presented in this section are extracted from **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1986**, the same report referenced in Section 3.1. These data have been subsequently revised by individual utilities.

As large nuclear and coal-fired units currently under construction are completed, some regions of the State are expected to experience significant excess capacity, at least in the short term. GSU recently entered such a state upon the completion of the River Bend project. EPEC is also facing relatively high reserve margins with completion of the Palo Verde project. HL&P, CPSB, and CP&L are likely to experience temporary capacity surpluses attributable to the South Texas Nuclear Project (STNP) if the second unit of that project is completed.

Meanwhile, other utilities in Texas are currently facing capacity deficiencies or may experience such problems in the future. Delays in the licensing of the Comanche Peak Nuclear Project have left the Texas Utilities Electric Company (TUEC) and Brazos Electric Power Cooperative (BEPC) with a capacity deficiency and have prompted TUEC to purchase cogenerated power produced in the Houston area.

Capacity deficiencies may compromise the reliability of a system, while capacity surpluses may impose unnecessary costs on ratepayers or shareholders. Among the possible solutions to such problems are increased utilization of cogenerated power produced along the Gulf Coast and capacity transactions between utilities. Further, by taking advantage of excess capacity in a neighboring system, a utility's need to construct additional generating capacity could be delayed or eliminated. The feasibility and attractiveness of such options depend largely on the operation and configuration of the State's bulk power transmission system, as well as institutional and regulatory arrangements.

On a statewide basis, if the current capacity expansion and energy efficiency plans developed by each of the State's generating electric utilities are realized, Texas will have adequate capacity resources to meet its growing electrical needs over the next decade. This conclusion holds for both the electric peak demand forecasts developed by each of the utilities serving Texas and the independent projections developed by the staff of the PUCT.

In the past, the level of reliability of power generation in Texas has been very high. Reserve margins, the difference between expected available capacity and anticipated demand, provide a simple measure of the expected reliability of an electric power system.

Based on the Commission's peak demand forecasts and using target reserve margins in the 20-25 percent range, some 16,500 MW of additional capacity will be required during the next ten years. Of this total, 10,200 MW is under construction which is not deferred in the staff analysis. The remaining 6,300 MW which must be added during the latter half of the 1986-95 period could be supplied by a combination of four major capacity sources:

- cogeneration and small power producers
- interregional purchased power
- generating unit life extension projects or improving existing plant efficiency
- conventional power plants

Of these four sources, cogeneration and conventional power plants will most likely provide the major contributions to capacity needs in the period. While it appears that there could be sufficient cogeneration to supply nearly all of the capacity needs during the period, this option involves significant uncertainty. Given the relatively long lead times required for planning and construction of base load power plants, it would not be prudent to defer plans for all conventional capacity until the future development of cogeneration and other potential supply-side options is more certain. However, deferral of some utility planned capacity may be prudent, as cogeneration contracts have been demonstrated to be economically competitive with utility-constructed base load plants.

Table 3.2-1 lists recommended plant additions during the next ten years, with generating units grouped by the year that they are expected to first serve the summer peak.

TABLE 3.2-1

1986-95 Generating Unit Additions

Year*	Plant	Unit	Net Rating (MW)	Utility	Utility Owned (MW)	Texas Allocated (MW)	Primary Fuel Type	Location	On Line Date	Current Status	Cost ($/KW)
1986											
	Palo Verde	1	1,270	EPEC	200	160	Nuclear	Phoenix,Ar.	Dec-85	Existing	NA
	River Bend	1	940	GSU	658	263	Nuclear	E.Baton Rouge,La.	Jan-86	Existing	NA
	Limestone	1	720	HL&P	720	720	Lignite	Limestone,Tx.	Dec-85	Existing	903
	Dolet Hills	1	640	SWEPCO	257	141	Lignite	DeSoto,La.	Apr-86	Existing	877
				NETEC	38	38	Lignite	DeSoto,La.	Apr-86	Existing	877
	1986 TOTAL					1,322					
1987											
	Palo Verde	2	1,270	EPEC	200	160	Nuclear	Phoenix,Ar.	Oct-86	99.9% Comp.	NA
	Limestone	2	720	HL&P	720	720	Lignite	Limestone,Tx.	Dec-86	61% Comp.	903
	Oklaunion	1	665	WTU	364	364	Coal	Wilbarger,Tx.	Dec-86	80% Comp.	587
				CP&L	119	119	Coal	Wilbarger,Tx.	Dec-86	80% Comp.	587
	Combustion Turbines			COA	105	105	Nat. Gas	Travis,Tx.	May-87		143
	Longhorn Hydro		3	COA	3	3	Hydro	Travis,Tx.	May-87		3,333
	1987 TOTAL					1,471					
1988											
	Palo Verde	3	1,270	EPEC	200	160	Nuclear	Phoenix,Ar.	Jun-87	98% Comp.	NA
	South Texas	1	1,250	HL&P	385	385	Nuclear	Matagorda,Tx.	Jun-87	84% Comp.	2,288
				CPSB	350	350	Nuclear	Matagorda,Tx.	Jun-87	84% Comp.	2,288
				CP&L	315	315	Nuclear	Matagorda,Tx.	Jun-87	84% Comp.	2,288
				COA	200	200	Nuclear	Matagorda,Tx.	Jun-87	84% Comp.	2,288

*Year unit first serves the summer peak.

TABLE 3.2-1 (Continued)

1986-95 Generating Unit Additions

Year*	Plant	Unit	Net Rating (MW)	Utility	Utility Owned (MW)	Texas Allocated (MW)	Primary Fuel Type	Location	On Line Date	Current Status	Cost ($/KW)
	Comanche Peak	1	1,150	TUEC	1,010	1,010	Nuclear	Sommerville,Tx.	Jul-87	99% Comp.	2,297
				TMPA	71	71	Nuclear	Sommerville,Tx.	Jul-87	99% Comp.	2,297
				BEPC	44	44	Nuclear	Sommerville,Tx.	Jul-87	99% Comp.	2,297
				TEX-LA	25	25	Nuclear	Sommerville,Tx.	Jul-87	99% Comp.	2,297
	Fayette	3	400	LCRA	400	400	Lignite	Fayette,Tx.	Jan-88	23% Comp.	1,171
	Permian Basin CT	1	190	TUEC	190	190	Nat. Gas	Ward,Tx.	Jan-88	Proposed	440
	Town Bluff	1	6	SRG&T	2	2	Hydro	unknown	Jan-88	Proposed	NA
	1988 TOTAL					3,152					
1989											
	South Texas	2	1,250	HL&P	385	385	Nuclear	Matagorda,Tx.	Jun-89	55% Comp.	2,288
				CPSB	350	350	Nuclear	Matagorda,Tx.	Jun-89	55% Comp.	2,288
				CP&L	315	315	Nuclear	Matagorda,Tx.	Jun-89	55% Comp.	2,288
				COA	200	200	Nuclear	Matagorda,Tx.	Jun-89	55% Comp.	2,288
	Comanche Peak	2	1,150	TUEC	1,010	1,010	Nuclear	Sommerville,Tx.	Jan-88	72% Comp.	2,297
				TMPA	71	71	Nuclear	Sommerville,Tx.	Jan-88	72% Comp.	2,297
				BEPC	44	44	Nuclear	Sommerville,Tx.	Jan-88	72% Comp.	2,297
				TEX-LA	25	25	Nuclear	Sommerville,Tx.	Jan-88	72% Comp.	2,297
	Municipal Waste		20	COA	20	20	Refuse	Travis,Tx.	Nov-88		3,500
	1989 TOTAL					2,420					
1990											
	Morgan Creek CT	1	400	TUEC	400	400	Nat. Gas	Mitchell,Tx.	Jan-90	Proposed	501
	DeCordova CT	1	260	TUEC	260	260	Nat. Gas	Hood,Tx.	Jan-90	Proposed	504
	Permian Basin CT	2	110	TUEC	110	110	Nat. Gas	Ward,Tx.	Jan-90	Proposed	503

*Year unit first serves the summer peak.

TABLE 3.2-1 (Continued)

1986-95 Generating Unit Additions

Year*	Plant	Unit	Net Rating (MW)	Utility	Utility Owned (MW)	Texas Allocated (MW)	Primary Fuel Type	Location	On Line Date	Current Status	Cost ($/KW)
	Municipal Waste		36	CPSB	36	36					
	1990 TOTAL					806					
1991											
	Twin Oak	1	750	TUEC	750	750	Lignite	Robertson,Tx.	Jan-91	15% Comp.	1,608
	Calvert	1	156	TNP	156	156	Lignite	Robertson,Tx.	Jul-90	Proposed	1,390
	Miller	4	100	BEPC	100	100					
	1991 TOTAL					1,006					
1992											
	Twin Oak	2	750	TUEC	750	750	Lignite	Robertson,Tx.	Jan-92	10% Comp.	894
	Calvert	2	156	TNP	156	156	Lignite	Robertson,Tx.	Jul-91	Proposed	1,395
	Miller	5	150	BEPC	150	150					
	1992 TOTAL					1,056					
1993											
	Lignite		500	CPSB	500	500					
	Fayette	4	400	LCRA	400	400	Lignite	Fayette,Tx.	Jul-92	Proposed	888
	Calvert	3	156	TNP	156	156	Lignite	Robertson,Tx.	Jul-92	Proposed	1,503
	Miller	6	150	BEPC	150	150					
	1993 TOTAL					1,206					
1994											
	San Miguel	2	400	BEPC	200	200					
				STEC	200	200	Lignite	Atascosa,Tx.	Jan-94	Proposed	2,000
	Combustion Turbines		225	SWEPCO	225	124	Nat. Gas	unassigned	Dec-93	Proposed	352

*Year unit first serves the summer peak.

TABLE 3.2-1 (Continued)

1986-95 Generating Unit Additions

Year*	Plant	Unit	Net Rating (MW)	Utility	Utility Owned (MW)	Texas Allocated (MW)	Primary Fuel Type	Location	On Line Date	Current Status	Cost ($/KW)
	Calvert	4	156	TNP	156	156	Lignite	Robertson,Tx.	Jul-93	Proposed	1,583
	Combustion Turbine		75	WTU	75	75	Nat. Gas	unassigned	Dec-93	Proposed	352
	Denver City	4	50	SPS	50	38	Nat. Gas	Yokum,Tx.	Jan-91	Refurb/React	68
	Roswell GT		10	SPS	10	8	Nat. Gas	Chaves,NM.	Jan-91	Refurb/React	164
	1994 TOTAL					801					
1995											
	Forest Grove	1	750	TUEC	750	750	Lignite	Henderson,Tx.	Jan-93	11% Comp. Comp.	1,649
	Coal	1	400	LCRA	400	400	Coal	unassigned	Jul-94	Proposed	932
	Moore County	3	48	SPS	48	36	Nat. Gas	Moore,Tx.	Jan-92	Refurb/React	80
	Cunningham GT	1	25	SPS	25	19	Nat. Gas	Lea,NM.	Jan-92	Refurb/React	128
	Cunningham GT	2	25	SPS	25	19	Nat. Gas	Lea,NM.	Jan-92	Refurb/React	278
	1995 TOTAL					1,224					
	TOTAL in 1986-95 Plan					14,463					

*Year unit first serves the summer peak.

Approximately 4,000 MW of primarily coal and lignite-fired base load capacity scheduled in current utility filings has been deferred beyond 1995 in this staff plan as a result of the lowered demand forecast and somewhat higher contributions anticipated from cogeneration. Tables 3.2-2, 3.2-3, and 3.2-4 and Figure 3.2-1 summarize the demand and capacity forecasts for Texas during the 1986-95 period.

As noted in Table 3.2-2, the staff's recommended resource plan results in a 22.8 percent reserve margin in 1995. However, there are a number of factors which could potentially result in lower than planned reserves for the State. The South Texas and Comanche Peak nuclear projects, which represent nearly 30 percent of the scheduled capacity additions during the 10-year period, may encounter additional construction and licensing problems. Cogeneration, which represents nearly 30 percent of the capacity scheduled to be added during the period, also involves considerable uncertainty.

3.3 Generation Mix

One economic force driving bulk power transactions is the ability of utilities with excess capacity to obtain favorable fuel prices relative to other ERCOT members. Since the marginal fuel source for ERCOT utilities is predominantly natural gas, this fuel is the primary focus of this section.

A major consideration in determining the investment strategy of the Texas utilities over the past decade has been the desire to obtain a greater degree of fuel diversification. Table 3.3-1 and Figure 3.3-1 provides data on statewide historical and projected capacity, by fuel type. The 1995 capacity mix is calculated from the capacity projections presented in the previous section. In 1975, with the exception of the TUEC lignite-fueled generation and a very small amount of hydro power, Texas was almost completely dependent upon natural gas and oil. As a result of rising energy prices and associated

TABLE 3.2-2

State of Texas
Capacity and Reserve Requirements, 1986-95
(MW)

Year	Net System Capacity	Unadjusted Peak Demand	Inter-ruptible	Conserv/ Load Mgmt	Firm Peak Demand	Net Reserve	Reserve Margin (%)	Low Case Excess	Base Case Excess	High Case Excess
1986	57,439	48,050	991	209	46,381	11,058	23.8	4,101	1,782	-537
1987	58,656	49,693	1,035	369	47,806	10,850	22.7	3,679	1,289	-1,102
1988	61,651	51,012	723	1,182	48,615	13,036	26.8	5,744	3,313	882
1989	64,173	52,266	660	2,004	49,106	15,067	30.7	7,701	5,246	2,791
1990	64,774	53,235	602	2,824	49,310	15,464	31.4	8,068	5,602	3,137
1991	65,043	54,828	638	3,623	50,061	14,982	29.9	7,473	4,970	2,467
1992	65,962	56,891	653	4,421	51,299	14,663	28.6	6,968	4,403	1,838
1993	68,247	59,277	668	5,220	52,855	15,392	29.1	7,464	4,821	2,178
1994	68,959	61,847	683	6,017	54,596	14,363	26.3	6,174	3,444	714
1995	69,334	64,560	698	6,816	56,476	12,858	22.8	4,387	1,563	-1,261

Notes:
1) Net System Capacity equals installed capacity plus firm purchases, minus firm sales, plus cogeneration purchases, plus supply side alternatives.
2) Unadjusted peak demand forecasts include interruptible loads and exclude potential conservation and load management impacts.
3) Firm peak demand equals unadjusted peak demand minus interruptible loads, minus conservation and load management impacts, and includes a one percent diversity factor.
4) Net reserve equals net system capacity minus firm peak demand.
5) Reserve margin equals net reserve divided by firm demand, multiplied by 100.
6) Low case excess equals net system capacity minus firm demand multiplied by 1.15.
7) Base case excess equals net system capacity minus firm demand multiplied by 1.20.
8) High case excess equals net system capacity minus firm demand multiplied by 1.25.

TABLE 3.2-3

State of Texas
Net System Capacity, 1986-95
(MW)

Year	Installed Capacity	Planned Added	Planned Retired	Firm Purchases	Firm Sales	Firm Cogeneration	Supply Side Alternatives	Net System Capacity
1986	53,804	1,375	784	3,224	1,250	1,617	44	57,439
1987	54,962	1,477	319	2,786	1,472	2,254	125	58,656
1988	58,053	3,168	77	2,075	805	2,136	192	61,651
1989	60,428	2,420	145	2,101	817	2,236	224	64,173
1990	61,019	806	115	1,993	799	2,336	224	64,774
1991	60,708	906	467	2,105	842	2,848	224	65,043
1992	61,022	1,086	772	2,078	710	3,348	224	65,962
1993	62,825	1,056	103	2,171	721	3,748	224	68,247
1994	63,144	1,189	470	2,419	676	3,848	224	68,959
1995	63,125	1,288	493	2,391	634	4,228	224	69,334

Notes:
1) Planned additions and retirements are conventional generating plants.
2) Firm purchases and sales include intrastate and interstate transactions between utilities, pursuant to firm power contracts.
3) Firm cogeneration includes capacity purchased from cogenerators pursuant to a firm power contract.
4) Supply side alternatives include capacity additions from efficiency improvements and renewable energy sources.
5) Net system capacity equals installed capacity plus firm purchases, minus firm sales, plus firm cogeneration purchases, plus supply side alternatives.

TABLE 3.2-4

State of Texas: Installed Capacity, 1986-95
(MW)

Year	Gas/Oil	Coal	Lignite	Nuclear	Hydro/ Other	Installed Capacity
1986	37,313	7,852	7,872	489	278	53,804
1987	37,108	8,326	8,592	649	287	54,962
1988	37,228	8,319	8,992	3,209	304	58,053
1989	37,183	8,319	8,992	5,609	324	60,428
1990	37,783	8,319	8,992	5,609	360	61,019
1991	37,217	8,319	9,148	5,609	360	60,708
1992	36,679	8,319	10,054	5,609	360	61,022
1993	36,676	8,319	11,860	5,609	360	62,825
1994	36,439	8,319	12,416	5,609	360	63,144
1995	36,020	8,719	12,416	5,609	360	63,125

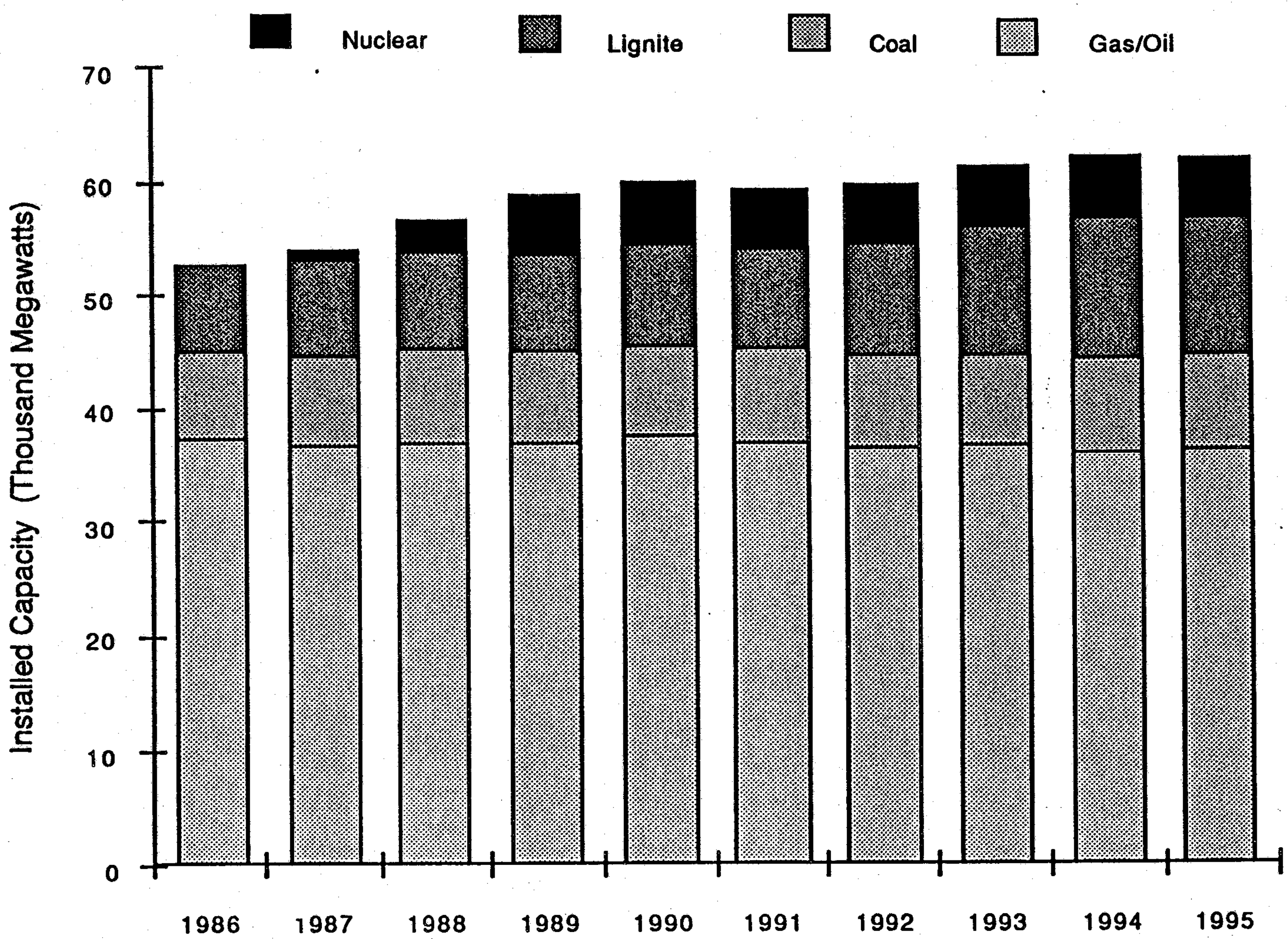

Figure 3.2-1 Installed Generating Capacity in The State of Texas between 1986 - 1995.

TABLE 3.3-1

Texas Historical and Projected Capacity and Energy Share by Fuel Type
(Percent)

	1975*		1985*		1995*	
Fuel	Capacity	Energy	Capacity	Energy	Capacity	Energy
GAS	94.8	89.6	69.0	55.2	53.0	36.7
OIL	0.3	1.5	0.3	0.2	0.1	0.4
COAL	0.3	0.3	15.6	24.2	16.1	21.5
LIGNITE	4.1	7.9	11.6	19.4	19.6	30.5
HYDRO	0.5	0.5	0.5	0.3	0.5	0.2
NUCLEAR	0.0	0.0	0.0	0.0	7.4	10.4
OTHER	0.0	0.1	3.0	0.9	3.3	0.3

***Derived from Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1986,** Tables I.C.1, I.C.2, and I.C.3.

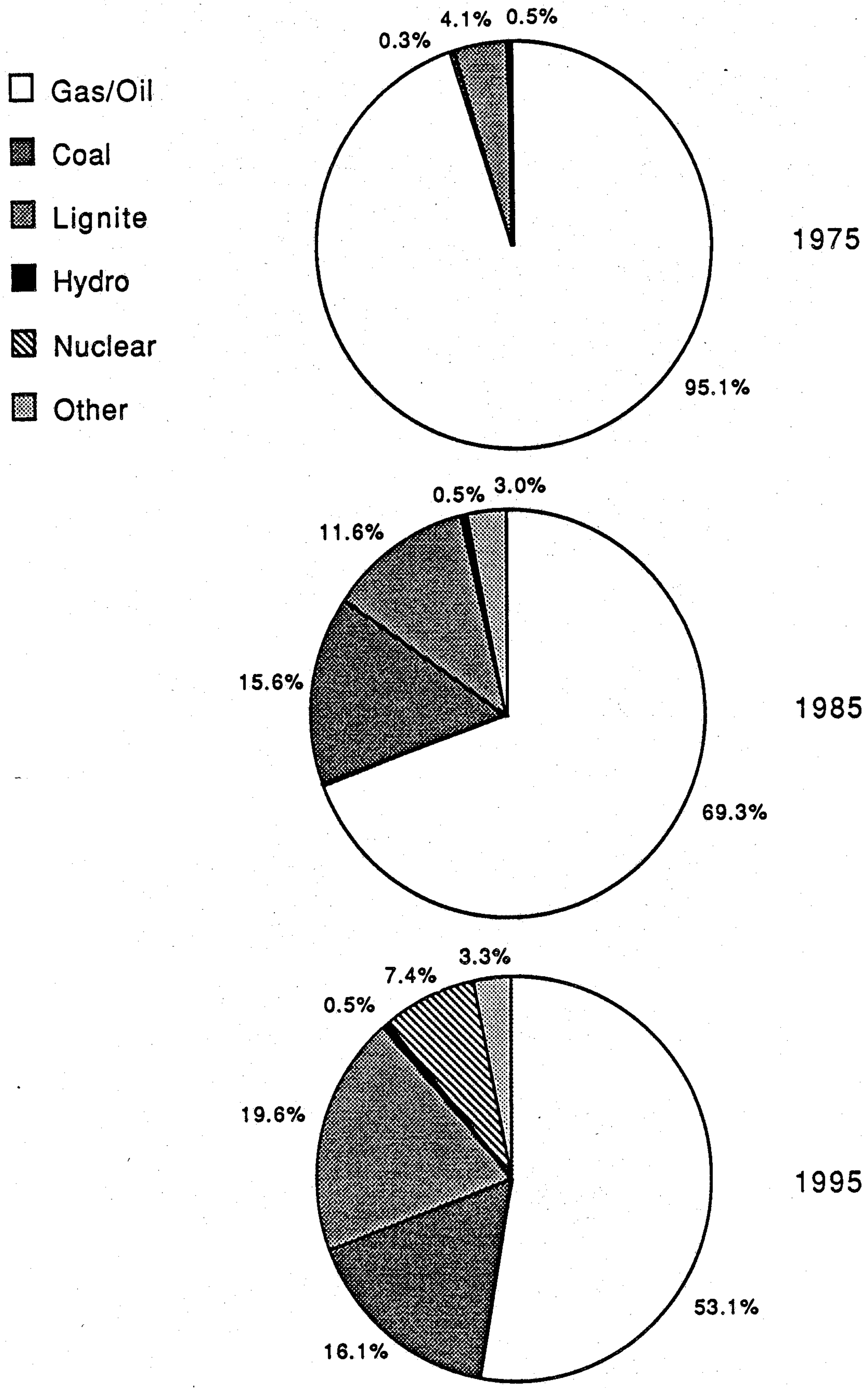

Figure 3.3-1 Fuel Mix of Generating Capacity In The State of Texas

federal and state mandates to inhibit construction of base load gas and oil-fueled generation, Texas opted for a more diversified generation mix investment strategy.

From 1975 to 1985, lignite and coal generating capacity increased from less than 5 percent of total system capacity to more than 27 percent. Total statewide energy produced from these resources increased even more dramatically, from about 8 percent to more than 43 percent. Over the same ten-year period gas and oil capacity fell from 95 percent to less than 70 percent of total system capacity while their share of energy production fell from about 90 percent to 55 percent. As gas and oil prices accelerated rapidly during the late 1970s and early 1980s, the decision to switch to lignite, coal, and nuclear seemed a wise one. The "other" category, shown in Figure 3.3-1, accounted for some 3 percent of statewide generation in 1985. This category is comprised mainly of cogeneration and small power producers.

Many of the utilities within Texas, as their previous contractual obligations expired, have been making the majority of their natural gas purchases in the short-term, interruptible, spot market. In fact, a substantial number of docketed fuel cases that have come before the Commission a few years after natural gas deregulation have been to reduce the portion of Texas ratepayers bills associated with fuel charges. But price declines for such a valuable resource are not likely to continue. An important question that utility fuel procurement policies must address is when to leave the relatively inexpensive spot market and secure fuel supply arrangements in which a premium must be paid for reliability. Fuel procured in the spot market does not provide this long-term reliability of supply.

3.4 Cogeneration

Cogeneration is a highly efficient means of utilizing the State's natural gas resources. A 275 MW cogeneration project typical of those on the Gulf Coast generates electric power at an equivalent heat rate of 7,645 BTU/KWH[1]. This equivalent heat rate is known as the fuel chargeable to power and is obtained by subtracting the amount of fuel required to produce process heat in a typical industrial boiler from the firing rate of the cogeneration system. The overall thermal efficiency of the cogeneration project in this reference is 55.7%. In comparison, the same amount of electric energy and process heat could be produced by a utility power station operating at a heat rate of 10,000 BTU/KWH and an industrial boiler operating at an efficiency of 85% resulting in an overall thermal efficiency of 45.6%.

As of February, 1987, Texas had 4,116 MW of existing cogeneration capacity with 1,183 MW under construction and 3,048 MW being proposed over the next two years[2]. Less than half of the existing capacity is sold under long-term, firm contracts with capacity as well as energy payments. The remainder is either under short-term, firm contracts with TUEC or is sold on an as-available basis. Another estimate projects total cogeneration technical potential to be about 17,500 MW.[3]

One major aspect of this study is an assessment of the amount of cogeneration which may be efficiently integrated into the Texas interconnected system over the next few

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[1]Kepner, John, Joe King and Tom Edmunds, **PUCT Working Paper No. 85-2, Cogeneration Development in Texas: Problems and Issues**, Texas Public Utility Commission, November, 1985.

[2]See **Cogeneration Database**, February, 1987 in Appendix E for details.

[3]Baughman, M., et.al., **Cogeneration in Texas**, Center for Energy Studies, University of Texas, November, 1986.

years. Cogeneration is likely to be beneficial to the ratepayers if it is available at a cost less than the cost of utility-constructed units and its presence in the system does not cause technical problems -- transmission reliability and generation scheduling -- to the utilities. Because of data limitations, the uncertain outcome of currently docketed issues, and the uncertain potential for future development, treatment of cogeneration in this study is limited to capturing known and reasonably predictable "firm" cogeneration (as opposed to non-firm, or as-available) arrangements.

In this study, a complete economic evaluation of the cogeneration alternative is not made. An economic evaluation of the cogeneration alternative would involve a comparison of all payments made to cogenerators with the fixed and variable costs of planned utility generating facilities. This type of analysis is not included in the report because the MAPS/MWFLOW program does not model fixed costs; the program simply minimizes fuel and other variable costs given available generation capacity. Thus, the issue of how much cogeneration should be purchased and at what price is not addressed.

While the Avoided Cost dockets provide the cogeneration community with the cost of the avoided unit, this cost represents only a ceiling price. Not surprisingly, the prices paid to cogenerators for capacity have, in every case subsequent to the avoided cost dockets, been less than previous estimates of full avoided costs. Rather than attempting to determine how much cogeneration might be available under different avoided cost scenarios, this study assumes various amounts of cogenerated power are available to the interconnected system and analyzes the alternative results derived from the model.

Cogeneration involves the sequential production of two products, typically electric power and useful thermal energy. The ability to use thermal energy that is considered as waste in conventional electricity generation results in a very high thermal efficiency for cogeneration. Because of the proprietary nature of manufacturing processes, the technical information for cogeneration plants is not made available to the public, and the true characteristics that reflect the high thermal efficiency of cogeneration cannot be captured. Instead, this study develops projections of energy payment streams under three of the four firm cogeneration contracts currently in place for HL&P. These payment stream projections reflect only the value of cogenerated power from the perspective of the utilities (as well as consumers) and not the actual production cost of cogenerated electricity. Value, in this instance, should capture the costs that a utility would probably have incurred had the cogenerated power not been available. An example of these energy payment calculations is provided in Chapter 4. These calculations include variable operation and maintenance costs as well as fuel costs which are based on both lignite and natural gas. This type of lignite/gas payment stream was developed because, while the majority of the utility production being avoided is likely to be coal or lignite fueled, cogenerators have demonstrated substantially higher availability rates and may thus receive a premium if they should perform better than the capacity they replace.

Another major limitation of the study with regard to cogeneration is the narrow scope of the reliability issues examined. The reliability issues can be separated into two classes: those issues that relate to the cogenerator's incentives to provide power, and those issues that relate to the ability of the ERCOT transmission system to transmit cogenerated power from seller to buyer.

The first class of reliability issues arises from the fact that most cogenerators operate natural gas-fired facilities. In the past, natural gas has had very volatile prices. In the face of high and rapidly escalating natural gas prices, the incentives for cogeneration may change. One school of thought is that cogenerators will reap additional economic rewards in an environment of high gas prices. This is based upon the observation that cogeneration is an efficient means of utilizing natural gas. Thus, in an environment of high natural gas prices, cogenerators will enjoy a cost advantage relative to noncogenerating competitors.

An opposing viewpoint is that cogenerators will breach contracts with utilities if gas prices are too high. Since energy payments to cogenerators generally follow lignite prices more closely than gas prices, the cogenerator's variable costs may exceed revenues. Under these circumstances, the cogenerator's short-term incentive will be to halt production.

A key factor in determining which of these two events is more likely, is how an increase in natural gas prices will affect the price of those products produced by cogenerators. If the product price increases in tandem with rising gas prices, then revenue will continue to exceed variable cost and the incentive to cogenerate remains. On the other hand, if the product price remains stable or decreases, then revenue will fall below variable cost and the cogenerator's incentive to continue production will be eliminated. Since the Commission does not have access to information regarding the internal economics of cogeneration projects, this class of reliability issues is not addressed.

With regard to the second class of reliability issues, the study examines the capability of the bulk power transmission system to move cogenerated power from the Gulf Coast region, where it is abundant, to inland areas where capacity is needed. However, the limited computer resources allow only a small number of transmission lines to be monitored for possible overload conditions. Therefore, the study results should be viewed as general indications of the practicality of transmitting cogenerated power, rather than a rigorous transfer limitation study.

Transmission feasibility is a significant problem in Texas because the vast majority of cogenerated power is expected to be located along the Gulf Coast, in the HL&P service territory. HL&P, however, currently indicates that it cannot commit to purchase additional firm cogenerated power until the mid-1990s. The problem to be addressed now concerns whether this energy, which may represent the cheapest alternative available (see Table 3.4-1), can be transmitted to the regions of Texas where it is most needed.

ERCOT contends that the bulk power transmission system is reaching its maximum capability to carry flows of power without risking the collapse of the entire system. The feasibility of transferring cogenerated power when transmission constraints are binding depends upon the degree of scheduling control the utility has over the operations of the cogeneration facility. In this report, this control is referred to as the degree of "dispatchability" (meaning in this context, the ability to control generation into the interconnected system in either an upward or downward direction) that the cogenerator grants to the host utility (the utility in the service area in which the cogenerator resides), although control may also be given to the receiving utility. Dispatchability may vary from no control over the cogenerator to a requirement that the cogenerator be "load following" -- treated just as another generating unit on the utility's system. The tendency to date is something between the two extremes where cogenerators offer a limited degree of control over the operations of their facilities.

Dispatchability is required by the utilities because, if operational problems arise, the host or receiving utility must have the capability to adjust the generation levels of the cogenerators, just as it does with its own generating units. Generally, the maximum amount that a cogeneration facility can be relied upon to reduce its output into the interconnected system is determined by two sets of constraints. One set refers to the thermal and electrical energy requirements of the cogenerator. The second set refers to the operational requirements of the utilities, which are affected by the transfer of the

TABLE 3.4-1

Cogeneration and Conventional Power Plant Cost Comparison

Utility	Contract/Plant Type	Capacity Cost ($/KW/year)	Capacity Cost (¢/KWH)	Energy Cost (¢/KWH)	Total Cost (¢/KWH)
<u>1988 Cogen Cost:</u>					
HL&P	Avoided Cost	159	2.1	3.2	5.3
HL&P	Cogen1	204	2.7	3.2	5.9*
HL&P	Cogen2	112	1.5	3.2	4.7
HL&P	Cogen3	59	0.8	3.2	4.0
TUEC	Avoided Cost	154	2.1	2.3	4.4
TUEC	Cogen1	60	0.8	3.3	4.1
TNP	Avoided Cost	131	1.8	2.1	4.1
<u>1988 Utility Plant Cost:</u>					
GSU	River Bend	933	15.2	1.3	16.5
HL&P	STNP 1	684	11.2	1.0	12.1
EPEC	Palo Verde	546	8.9	0.8	9.8
TUEC	Comanche Peak 1	505	8.2	0.6	8.8
HL&P	Limestone 2	266	4.3	2.5	6.8
WTU	Oklaunion	161	2.6	2.1	4.7
SPS	Tolk 2	125	2.0	2.1	4.1

*Signed before avoided cost rate determination

Notes:
1) Details of most Cogen Contracts are proprietary.
2) Only the utilities shown have avoided capacity costs prior to 1990.
3) Cogen capacity costs (¢/KWH) based on an 85% capacity factor.
4) Plant capacity costs based on a 22% fixed charge rate and 70% capacity factor.
5) Plant energy cost based on previous PUCT staff estimated fuel costs.

cogenerated power. In general, these constraints must permit the affected utilities to operate their systems in a reliable manner. In particular, the utility should have sufficient scheduling control over the operation of the cogeneration facility to avoid system control problems under varying load conditions. In this study no cogeneration dispatchability is assumed. Cogeneration plants are assumed to operate at predetermined fixed output levels.

In addition to direct sales, some cogenerators have expressed interest in participating in the ERCOT energy broker, particularly if the transmission is strengthened to handle a higher level of bulk power transactions. Such arrangements could expand the market for cogenerated electricity and lead to a more competitive environment among power producers resulting in more economical electric energy for end users. However, ERCOT utilities have indicated that there are difficulties in determining whether these types of arrangements could produce any residual benefits to the ratepayers, citing problems such as reductions in utility savings, control and scheduling, replacement capacity and energy, accounting and billing costs, and reduce transmission reserve capacity. At the present time, it is not possible to assess this possibility due to the lack of technical data from cogenerators.

3.5 System Coordination in ERCOT

Much of the analysis developed in this study ultimately rests on the capability of the interconnected system to permit enhanced bulk power transfers. While capability, to a large extent, is a function of the configuration of the system, and because the production/consumption of electricity requires the interaction of a large number of complex variables, more dynamic elements must be considered. Because this project is more policy oriented and is broad in scope, operational situations that tend to occur on a very short-term or infrequent basis are not explicitly considered.

The seven utilities modeled in this study account for more than 25,396 miles of transmission lines at voltage levels greater than 69 KV. The approximate pole miles of each class of line are shown on Table 3.5-1. A detailed map of the transmission system and planned additions can be found at the end of the Chapter.

In order to describe how the bulk power transmission system has been employed in Texas, the utilities have provided the staff with data on energy sales and purchases which occurred among the ERCOT members from January, 1980 through August, 1986. This data includes both firm and economy power exchanges, as well as transfers necessitated by equipment failures. Selected portions of this data for 1985 and 1986 are provided in Table 3.5-2. Table 3.5-3 provides total system sales for the seven ERCOT utilities represented in this study for 1985 and 1986.

ERCOT has established two control centers, in Dallas and Austin, to accommodate transactions and to insure supply reliability. The center in Dallas coordinates the operations primarily in North ERCOT, while the one in Austin coordinates the operations primarily in South ERCOT. The function of these control centers is to monitor power flows across members' service areas and take appropriate actions to prevent or minimize the loss of service in an emergency situation. In the event that one control center is disabled, the entire functions can be temporarily shifted to the other.

Currently, economy transactions among ERCOT members are made through a bulletin board and a brokerage system. While the bulletin board system has been in existence for years, the installation of the brokerage system was just completed in November 1986. The installation marked the second attempt by ERCOT to use the brokerage system. The

TABLE 3.5-1

Transmission Line by Voltage
(Approximate Pole Miles -- 1986)

	345 KV	138 KV	69 KV	Total
COA	210	120	78	408
LCRA	199	1,270	600	2,069
CPSB	294	489	9	792
HL&P	570	1,507	436	2,513
TUEC	2,650	5,208	2,673	10,531
CP&L	253	2,479	1,966	4,698
WTU	145	1,423	2,817	4,385
Total	4,321	12,496	8,579	25,396

TABLE 3.5-2

Selected Historical Bulk Power Transactions
(MWH)

Buyer	Seller	1985	1986*
HL&P	COA	202,579	215,576
HL&P	CPSB	252,055	166,805
E.E.†	HL&P	299,359	164,694
TUEC	Dow	507,649	303,300
TUEC	LCRA	171,596	
TUEC	Lyondell		733,280
TUEC	Texas Gulf		192,147
CP&L	C&SW	205,025	685,111
WTU	C&SW	1,781,051	993,002
WTU	COA	241,154	
PUB	CP&L	374,849	
PUB	HL&P		190,377
COA	E.E.†	235,504	144,892

*First eight months
†Economy Energy Supplied to ERCOT

TABLE 3.5-3

Total System Sales
(MWH)

Utility	1985	1986
TUEC	71,453,760	75,052,830
HL&P	55,311,034	54,332,505
CP&L	14,534,075	15,801,211
WTU	5,389,065	5,165,417
LCRA	6,460,268	7,561,234
COA	5,284,095	5,326,594
CPSB	9,445,539	10,428,670

first attempt was made during the early 1980s. At that time the volume of the transactions was insufficient to make the system useful.

The bulletin board system, handled by the two ERCOT control centers, is the simplest form of coordination among member utilities. It operates on a bidding concept. When a utility has excess capacity, it can post the quote at the FOB price and the available capacity on the bulletin board. The FOB price refers to the price at the boundary of the seller transmission system. All the member utilities have access to the posting. An interested member can contact the seller for the posted item and arrange for the shipment which may involve paying wheeling charges to affected members.

The transactions fall into two categories: economy A and economy B. Economy A is short term and fully interruptible. Availability is immediate and may last less than a few hours. The transaction can be interrupted by any party including those who wheel the power. Economy B is longer term and firm. The transaction must be arranged in advance by the affected parties and lasts several hours.

The brokerage system automates the matching between buyers and sellers for greatest overall savings. In one aspect, this is an approach of power pooling. Each hour, members will enter "blind" quotes to buy and sell power. No member will know the quotes from the others. The brokerage system then matches the highest offer to buy to the lowest bid to sell. The matching is repeated on the remaining quotes until all possible matches are made. The member utilities are then notified about the matches so they can initiate the transactions. No wheeling charges are assessed.

The kind of transfers suggested under the "pool operation" in this study are similar to those which might occur under the existing brokerage system. While all of the ERCOT utilities make use of economy transactions under the brokerage system to some degree, there is no mention of these transfers in any of the utilities' resource plans. Economy transactions are not usually planned; rather, they occur as operational opportunities arise. In most instances they are anticipated only several hours to a few days in advance. On the other hand, the types of transactions occurring in the MAPS/MWFLOW model are planned transfers and are presumably contracted for in advance. This level of coordination could evolve through more experience with the broker system and future enhancements based on information gained from its continued operation.

In addition to bulletin board and brokerage systems, other forms of transaction arrangements exist. Members of ERCOT regularly negotiate between one another and with cogenerators and small power producers to exchange power.

Under the bulletin board and broker systems, the total amount of energy exchanged was approximately 1,776 GWH in 1985, 2,296 GWH in 1986, and 3,494 GWH in 1987. In comparison, 183,000 GWH was generated by ERCOT utilities in 1986. ERCOT expects the level of transactions to increase considerably in the future under the brokerage system.

In addition to the bulletin board and brokerage systems, ERCOT has established numerous committees to develop operating agreements among member utilities. The ERCOT transmission planning criteria described below are an example of this type of coordination.

3.6 Transmission System Planning

At the present time there is no regulatory requirement for coordination of individual utility transmission system plans. Rather, each utility submits an application for line certification for each transmission line it proposes to construct. This process is described

Chapter 4
Reference Case Assumptions and Results

In this chapter, the results of MAPS/MWFLOW simulations are presented along with appropriate discussions and explanations. These discussions emphasize the comparison between "own-load" and "pool" operations under conditions which are characterized as "diverging" and "converging" natural gas prices. Under own-load operation, utilities are assumed to operate independently and no attempts are made to import or export energy on an economy basis. Under pool operation, utilities are assumed to be closely coordinated and exchange power in such a manner as to globally optimize resource allocation in the production of electricity. These two modes of operation represent two extreme cases of possible degrees of coordination among ERCOT members. ERCOT member utilities currently operate in a semi-autonomous mode, employing bulletin board and brokerage systems to achieve some coordination of operations.

In earlier drafts of this report, this chapter emphasized only a single fuel price scenario as a "base case" for each of the study years. However, as a result of the review meetings held in early December and written comments which were subsequently submitted by interested parties, the study staff has made several changes which led to the use of two reference cases for each study year, as well as a change in the study years to be emphasized. The first set of changes addresses inconsistencies in the model input data and the transmission line constraint set. In particular, the earlier heat rates reported for most of the TUEC gas-fired generating units were overstated by approximately 5% relative to the other ERCOT utilities and had to be corrected accordingly. Similarly, a detailed loadflow analysis (done by COA and LCRA) of the 2,190 different generation schedules for the 1990 base case results, indicated that many lines <u>not</u> contained in the constraint set were being loaded beyond their reliability limits at the calculated transactions level. The constraint set has since been increased from 96 to 290 lines to include those identified by the loadflow results. The combined effect of these changes reduced both the transactions level and the annual savings by approximately 5.5% and 12.6%, respectively. The detailed comments from the review process can be found in Appendix G.

A more significant source of change in the model results depends on the forecast of the state of the natural gas market and its effect on utility gas price differentials. When this study began in 1986, and as late as April, 1987, when forecasts were updated for use in the "final" model runs, it appeared that the existing natural gas supply surplus would be depleted by 1990. In this scenario, there would be a return to "normal" conditions of a single-tiered long-term contract market in Texas with significant inter-utility price differentials persisting into the future. By early 1988, at the time this study was expected to be completed, there were strong indications that the gas surplus had not disappeared and that the ERCOT utilities are still facing a two-tiered gas market in which short-term supplies can be acquired at prices much lower than available on long-term contracts. This short-term gas with low incremental prices uniformly available to the ERCOT utilities now exists and seems as likely to persist into the future as the higher priced scenario that was used earlier. As a result, for the forecast years of 1990 and 1995, both scenarios are presented as reference cases which define the potential range of transactions and savings. The 1988 case has been dropped, but additional emphasis has been accorded the historical cases for 1986, where the model inputs are known and the output can be compared to actual reported data.

It should be emphasized that the model results show only the range of short-term benefits which may be in the form of potential fuel savings and reduced production costs. At this stage of analysis, no suggestions are offered concerning the allocation of potential savings or mechanisms for passing any benefits on to the consumers of electricity.

The reference cases serve as a basis of comparison for other test scenarios in order to estimate the sensitivity of the results to changes in relevant parameters. The test scenarios implemented in the study and discussed in Chapter 5 are associated with parameters such as the level of cogeneration, demand, and fuel prices, which are expected to affect the volume of bulk power transactions.

For the 1990 and 1995 reference cases, the demand forecasts and capacity expansion plans provided by the utilities, as of April 1987, are used. PUCT demand forecasts form the basis of the alternative demand growth sensitivity cases in Chapter 5.

As with any study of this nature, this report is not intended to provide a single definitive estimate of the overall savings which may be realized through statewide bulk power transactions, but rather to establish reasonable boundary conditions. The emphasis of this report is on examining the operations of the State's electric power system under alternative conditions. In that context, no assessments of potential transactions, potential savings, or system reliability should be considered without regard to the particular assumptions under which they are derived.

4.1 Study Procedures

The results reported in this study rely heavily on the mathematical simulation of ERCOT system operations. From an engineering standpoint, the process of electricity production and transmission is well defined. Mathematical models are employed to simulate this process using known relationships. Such models of the operational behavior of utility systems have been widely used for several decades.

4.1.1 Data Sources

Most of the data used for this project fall into two categories: technical data and forecasts. Technical data are usually obtained from measurements and calculations using applicable principles of physics and engineering. Examples of this kind of data are heat rate, MW capacity, and fuel heat content. Technical data are stable and tend to fluctuate very little over time.

The forecasts are generally based on historical information that defines empirical relationships between forecast variables and those variables which influence them. Examples include demand forecasts, fuel price projections, and capacity expansion plans. Sometimes the forecasting problem is complicated by simultaneous interaction among variables. For example, capacity expansion plans are affected by demand forecasts which are affected by electricity prices that are affected, in turn, by capacity expansion plans.

Most of the required technical data were obtained from ERCOT and its member utilities, athough some minor adjustments were necessary to achieve consistency among utilities. Capacity expansion plans and demand forecasts were also provided by ERCOT member utilities, while additional demand forecasts were developed by the PUCT staff. Fuel price forecasts were developed by the PUCT staff using historical data, price escalation rates provided by Data Resources, Inc., or expected prices submitted by the ERCOT utilities.

4.1.2 Analytical Tools

There are several computer packages available commercially and in the public domain which may be used to model the utility industry at various levels of detail using various analytical techniques. Different packages emphasize different aspects of the electric power generation process, and have different strengths and weaknesses. Tradeoffs must be made when selecting a package. In this study, emphasis is placed upon examining the operational behavior of the state's utilities under different modes of coordination. One of the critical factors in studying the effects of coordination is the shipment of bulk power over a transmission network. The ability to model the constraints of the transmission system is a required feature for the computer package.

The computer package selected for this study is the Multi-Area Production Simulation with Megawatt Flow (MAPS/MWFLOW) computer program developed by General Electric (GE). This linear programming based optimization package simulates the supply side of the electric utility industry and searches for an operational configuration which will meet electricity demand at the lowest possible cost without exceeding physical or reliability limits imposed upon the system. MAPS/MWFLOW was selected because it allows the user to model the transmission system and its interaction with the unit commitment and economic dispatch procedures. A complete discussion of the MAPS/MWFLOW program, its underlying methodology, and its strengths and weaknesses is included in Appendix A.

4.1.3 Model of Utility Systems in ERCOT

Seven major utilities whose service areas are within ERCOT are explicitly modeled. These utilities are:

City of Austin (COA)
Lower Colorado River Authority (LCRA)
City Public Service Board of San Antonio (CPSB)
Texas Utilities Electric Company (TUEC)

Houston Lighting & Power (HL&P)

Central Power & Light (CP&L)

West Texas Utilities (WTU)

Together, they own more than 95 percent of the generating facilities and nearly all of the bulk power transmission lines in ERCOT. As requested by Central & South West Company (C&SW), CP&L and WTU are treated as a tight power pool under the name of their parent holding company. The four major interstate generating utilities in Texas are only weakly connected to the ERCOT system and are not explicitly included in the study.

4.1.4 Power Pooling and Bulk Power Transactions

During the course of this study, some concerns were raised that the focus of the study would be shifted to formal power pooling arrangements under which utilities in ERCOT would be centrally dispatched. Although bulk power transactions are related to power pooling in the generic sense, the implication should <u>not</u> be drawn that the results shown in this study would require such centralization and control. In fact, as discussed throughout this report, quite the contrary is true.

The term power pooling as used in this study refers to the coordination of system operation of interconnected utilities for reliability and/or economic purposes. There are different types of power pooling or degrees of coordination running the spectrum from "loose" to "tight" power pools. The ERCOT system is closer to being a "loose" power pool, where voluntary coordination is mainly for reliability purposes. A "tight" power pool is an interconnected system where generation capacity is centrally scheduled and dispatched without regard to ownership, and transmission lines are treated as purely common facilities for the use of the pool.

Historically, power pooling has been an evolutionary process. Once utilities are interconnected they tend to look for ways in which to improve their use of resources, ranging from sharing reserves to exchanging power to lower production costs. When opportunities arise to take advantage of available and more economical capacity, transactions will take place and many factors may cause these transactions to grow over time. More transactions require more complex coordinating procedures to be developed. Several utilities in the Northeast, where the systems are close together, have ultimately evolved into centrally dispatched systems to achieve maximum overall cost savings. However, others such as the Florida Electric Power Coordinating Group (FCG) use a brokerage system to facilitate power pooling. A similar system was initiated in ERCOT in November, 1986. The various forms of power pooling are mechanisms to facilitate bulk power transactions which minimize systemwide production costs. Although other mechanisms such as bilateral agreements and joint ownership are also used, they are not likely to yield minimum systemwide costs because they do not consider the entire interconnected system.

From a technical standpoint, a transaction can be initiated when at least three conditions are present: available generating capacity, price differentials, and available transmission capacity. While the central dispatch approach includes these factors in the process, the brokering approach analyzes the price differentials and available capacity from information supplied by participating utilities. The central dispatch approach, which is complex and costly to implement and maintain, may be suitable for systems that are closely connected and have a large volume of transactions. The brokering approach is simpler to develop and more suitable for dispersed systems with a lesser volume of transactions. Despite the obvious differences, both approaches can attain the same objective of minimizing overall system operating costs.

4.1.5 Operational Assumptions

The results from MAPS/MWFLOW runs, among other things, show a comparison between operation of pool members as isolated systems and operation as an integrated system.

When modeled as isolated systems, the individual systems are assumed to be independent so that each system schedules its generation to satisfy its own load. The net flow of energy across any boundary between two systems is always equal to zero and each system is assumed to maintain a minimum spinning reserve of 10 percent.

When modeled as an integrated system, the six systems are assumed to operate as though there exists a strong coordination among the system operators to create the most efficient operation of the entire pool. Theoretically, this means that the selection of a certain available generating unit is based on the economy of the pool, not just the company that owns it. As discussed earlier there are different pooling mechanisms to bring about this type of coordination.

In the reference case, it is assumed that there exists close coordination during unit commitment and economic dispatch only. The scheduling of maintenance is done independently by individual members of the pool without consulting one another while the spinning reserve of the pool is set at 10 percent to maintain the same level as the isolated operation. Since the global unit commitment ignores the spinning reserve requirements of individual members, it may result in units being undercommitted in one region while being overcommitted in another, thereby forcing the undercommitted region to rely on uninterruptible imported energy from other members. Therefore, some of the transactions which occur in the reference case are considered as firm transactions.

The limitations of MAPS/MWFLOW prohibit a completely accurate presentation of the ERCOT spinning reserve setting. ERCOT member utilities are grouped into north and south geographic regions. The major generating utilities in north ERCOT are WTU and TUEC, while those in south ERCOT are HL&P, COA, CPSB, LCRA, and CP&L. According to ERCOT operating guidelines, each group is required to maintain a spinning reserve during operation at least equal to the largest unit on line plus 100 MW. This spinning reserve requirement is then allocated among the members according to their size and capacity configuration. Most utilities maintain a spinning reserve slightly higher than that required by ERCOT.

Because of existing contractual arrangements, fuel requirements, or voltage support needs, several generating units in the data base have must-run status. Such units, as identified by the individual utilities, generate some electricity regardless of their economic merit. Most of these units are located in the HL&P area. In the study, these units are initially committed to run at their minimum capacity sections. The utilization of capacity sections above the minimum of the must-run units are then based on their economic merit.

Note that the use of the word "pool" in the remainder of this report refers to additional coordination to allow the economical operation of the ERCOT members. This meaning differs somewhat from the current pooling arrangement in ERCOT which focuses mainly on reliability.

4.1.6 Cogeneration

Cogenerators are typically classified into two groups: nonfirm and firm. Nonfirm cogenerators sell energy to utilities on an as-available basis. There is no obligation for these cogenerators to maintain output, and utilities are bound by law to buy all energy delivered at an avoided cost rate. The avoided cost calculation is based on the contribution to fuel savings, which depends on the timing and duration of energy injected into the system by the cogenerators.

Currently, the amount of nonfirm cogeneration is relatively small. Utilities recognize only firm cogeneration in their resource planning, and this study addresses only firm cogeneration. In subsequent discussions, all references to cogeneration refer only to firm cogeneration.

Firm cogenerators sign contracts with the utilities to provide both capacity and energy. The duration of a contract generally ranges from two to ten years. The energy payment is projected over the range of the contract based on the capacity mix to be displaced. The contractual obligation defines payment for cogenerated energy and capacity based upon the assumption that the utility can avoid building a new unit it needs for future demand during the contract period.

Since the transmission system representation of MAPS/MWFLOW can recognize the location of any generating unit, the location of cogenerators is modeled explicitly. For example, the location of a cogenerator can be in the service area of a utility other than the one with which it has a contract. This allows for the modeling of cogeneration contracts which involve wheeling.

Some utilities, such as HL&P, treat energy from cogeneration as "prescheduled" generation similar to hydro. Available energy from most cogenerators is relatively constant throughout a given year which means it is utilized as base-load generation. In this study, all cogenerating units have been assigned a must-run status to ensure continuous output. The availability factors are then adjusted to yield the expected output.

In the reference case, production costs of cogenerating units do not have any impact on savings because the must-run status forces the output from cogeneration to be identical under both own-load and pool operations.

Under the 1990 reference case scenario, HL&P and TUEC purchase power from cogenerators in accordance with the contracts listed in Table 4.1-1. Forecasts of energy payments to cogenerators are based upon terms in these existing power contracts, which specify two general methodologies for calculating energy payments. It should be noted that capacity payments to cogenerators are not included in these calculations. HL&P employs one method for calculation of energy payments while TUEC takes a different approach.

Contracts between HL&P and cogenerators involve an obligation on behalf of the cogenerator to provide capacity as well as energy. This allows the utility to avoid constructing the next unit in its generation expansion plan, typically a lignite-fired unit. Since a lignite-fired unit is displaced, firm power contracts compensate the cogenerator at an energy price which reflects the cost of operating a lignite-fired unit, with a premium based upon the cost of natural gas-fired generation. This premium is paid to the cogenerator only if the energy generated exceeds the energy that would have been generated by the lignite unit that the cogenerator displaces. A typical energy payment calculation for a firm power contract in which the cogenerator earns this premium is as follows:

$$P_E = P_L + P_G$$

where

P_E = total payment for cogenerated energy ($/MWH)

P_L = payment for lignite displacement ($/MWH)

TABLE 4.1-1

Cogeneration Projects

Project	MAPS Ref	Capacity (MW)	Purchasing Utility	Contract Duration
Occidental Chem.	Cogen 1	225	HL&P	1984-93
Dow Chem.	Cogen 2	325	HL&P	1985-94
Bayou Cogen	Cogen 3	270	HL&P	1985-94
Applied Energy Ser.	Cogen 5	25	HL&P	1986-96
Misc. Cogen	Cogen 10	396	HL&P	--
Dow Chem.	DWCOG	350	TUEC	1986-88
Texas Gulf Chem.	TGCOG	70	TUEC	1986-95
Cogen Lyondell	LYCOG	400	TUEC	1986-88
Enron 1	NOCOG	393	TUEC	1987-99
Wichita Falls	WFCOG	75	TUEC	1987-97
Falcon Seaboard	BSCOG	200	TUEC	1987-2000
Short Term Cogen	SHTCOG	100	TUEC	1987-89
Unspecified	CG89	306	TUEC	1989-97
"	CG93	300	TUEC	1993-97
"	CG91	306	TUEC	1991-97
"	CG92	300	TUEC	1992-97
"	CG94	200	TUEC	1994-97
"	CG95	200	TUEC	1995-97
	TOTAL	4,441		

P_G = payment for gas displacement as a result of the high availability of cogenerated energy ($/MWH)

P_L and P_G are calculated from the following formulas.

$$P_L = \frac{C_L}{C_{CG}}(F_L H_L + M_L)$$

$$P_G = \frac{(C_{CG} - C_L)}{C_{CG}}(F_G H_G + M_G)$$

where

C_L = capacity factor for the lignite unit had it not been displaced (percent)

C_{CG} = capacity factor for the cogenerator's unit (percent)

F_L = fuel cost for the displaced lignite unit ($/MMBTU)

H_L = heat rate for the displaced lignite unit (MMBTU/MWH)

M_L = operation and maintenance costs for the displaced lignite unit ($/MWH)

F_G = system incremental gas price ($/MMBTU)

H_G = system incremental heat rate for gas units (MMBTU/MWH)

M_G = system incremental operation and maintenance costs for gas units ($/MWH)

In contrast, TUEC considers its marginal capacity and energy source to be HL&P's system. For this reason, TUEC utilizes HL&P's incremental energy costs in its energy payment calculations.

Since all of the cogeneration contracts which are in effect for 1990 expire prior to 1995, the 1995 cogeneration energy payments for both HL&P and TUEC are estimated using the HL&P methodology. Purchase quantities are taken from individual utility resource plans.

4.1.7 Fuel Price Assumptions

A critical variable for both utility and non-utility generators in Texas is the volatility of fuel markets. While the "energy crisis" of the 1970s and early 1980s has -- at least for the time being -- abated, electricity producers remain concerned about the potential for a resurgence of fuel cost increases during the next several years. However, even with these expectations, much of the natural gas currently purchased by the utilities, except in the case of TUEC, is predominantly from the short-term (one month to one year) market. In several instances (HL&P, LCRA, and COA), the entire utility system gas requirements are satisfied by the short-term market. This situation is presumably appropriate today, but potentially could create problems if the markets tighten up before more secure long-term supplies can be arranged. Because of this fundamental uncertainty about the future structure of the gas market, two reference cases are developed for each study year. One of these cases is based on the return to a single-tiered, long-term market with "diverging" prices while the other is based on the continuance of the current two-tiered, short-term market with "converging" incremental prices for all of the ERCOT utilities.

Natural gas prices, which have exhibited substantial swings during the past several years, along with a variety of legislative/regulatory changes, have encouraged utilities to diversify away from natural gas-fired base load generating units. Utilities have opted instead to construct predominantly coal, lignite, and nuclear fueled generation. Along with this fuel mix diversification, utilities have also been required to purchase power from facilities which qualify as cogenerators or small power producers according to state and federal statutes. Most cogenerators employ natural gas as their primary fuel, but with a greater overall efficiency as a result of the sequential production of electric and thermal outputs. The existence and potential for such qualified cogenerators seems sufficient to promote continued use of this fuel source. The combined result of all of these changes is a more diversified mix of capacity for ERCOT and the State.

The diverging fuel price forecasts used in this study begin with prices based on existing contracts as of the beginning of 1987 from information supplied by the participating ERCOT utilities. The projections for the study periods are derived by applying the rates of change obtained from the **Winter, 1986-87, DRI Energy Review** and applied to the starting prices. In the diverging reference case for TUEC, HL&P, COA, and CPSB, the fuel prices used in the model represent each individual utility's average cost of fuel by fuel type, while the prices used for LCRA, CP&L, and WTU are based on individual supply contracts for plants served by different suppliers. These forecasts are shown in Table 4.1-2. The converging fuel price forecasts which produce a uniformly low price for each of the utilities were submitted by ERCOT in early 1988, and are shown in Table 4.1-3. Alternative fuel price projections and their effects are discussed in Chapter 5.

4.1.8 Demand characteristics

The generation requirements for the seven modeled utilities in 1990 are shown in Figures 4.1-1 through 4.1-7 by biweekly interval. These patterns, which represent load plus loss within the utilities' own service areas, are derived by the MAPS/MWFLOW program from 1985 historical hourly load data. The patterns for 1986 and 1995 are similar to those in 1990 because they are also derived from the same historical data.

TABLE 4.1-2

Projected Fuel Prices: Diverging Gas Prices
($/MMBTU)

		Gas	Coal	Lignite	Nuclear
COA	1990	2.58	2.03	N/A	0.62
	1995	4.22	2.79	N/A	0.86
LCRA	1990	2.29-2.34	2.03-2.07	2.07	N/A
	1995	3.74-3.83	2.72-2.75	2.07	N/A
CPSB	1990	3.18	2.07	N/A	0.51-0.57
	1995	4.84	2.76	N/A	0.86
HL&P	1990	2.15	2.35	1.50-2.02	0.71
	1995	3.52	3.13	1.89	0.86
TUEC	1990	3.15-3.95	3.27-3.97	1.09-1.50	0.34-0.62
	1995	5.15	3.27-3.97	1.48	0.86
CP&L	1990	2.39-3.43	2.44	N/A	0.71-0.91
	1995	3.82-5.61	3.18	N/A	0.86
WTU	1990	2.22-3.44	2.11	N/A	N/A
	1995	3.85-5.13	2.85	N/A	N/A

N/A -- not applicable

TABLE 4.1-3

Projected Fuel Prices: Converging Gas Prices
($/MMBTU)

		Gas	Coal	Lignite	Nuclear
COA	1990	2.46	2.03	N/A	0.62
	1995	3.78	2.79	N/A	0.86
LCRA	1990	2.46	2.03-2.07	2.07	N/A
	1995	3.78	2.72-2.75	2.07	N/A
CPSB	1990	2.46	2.07	N/A	0.51-0.57
	1995	3.78	2.76	N/A	0.86
HL&P	1990	2.46	2.35	1.50-2.02	0.71
	1995	3.78	3.13	1.89	0.86
TUEC	1990	2.46	3.27-3.97	1.09-1.50	0.34-0.62
	1995	3.78	3.27-3.97	1.48	0.86
CP&L	1990	2.46	2.44	N/A	0.71-0.91
	1995	3.78	3.18	N/A	0.86
WTU	1990	2.46	2.11	N/A	N/A
	1995	3.78	2.85	N/A	N/A

N/A -- not applicable

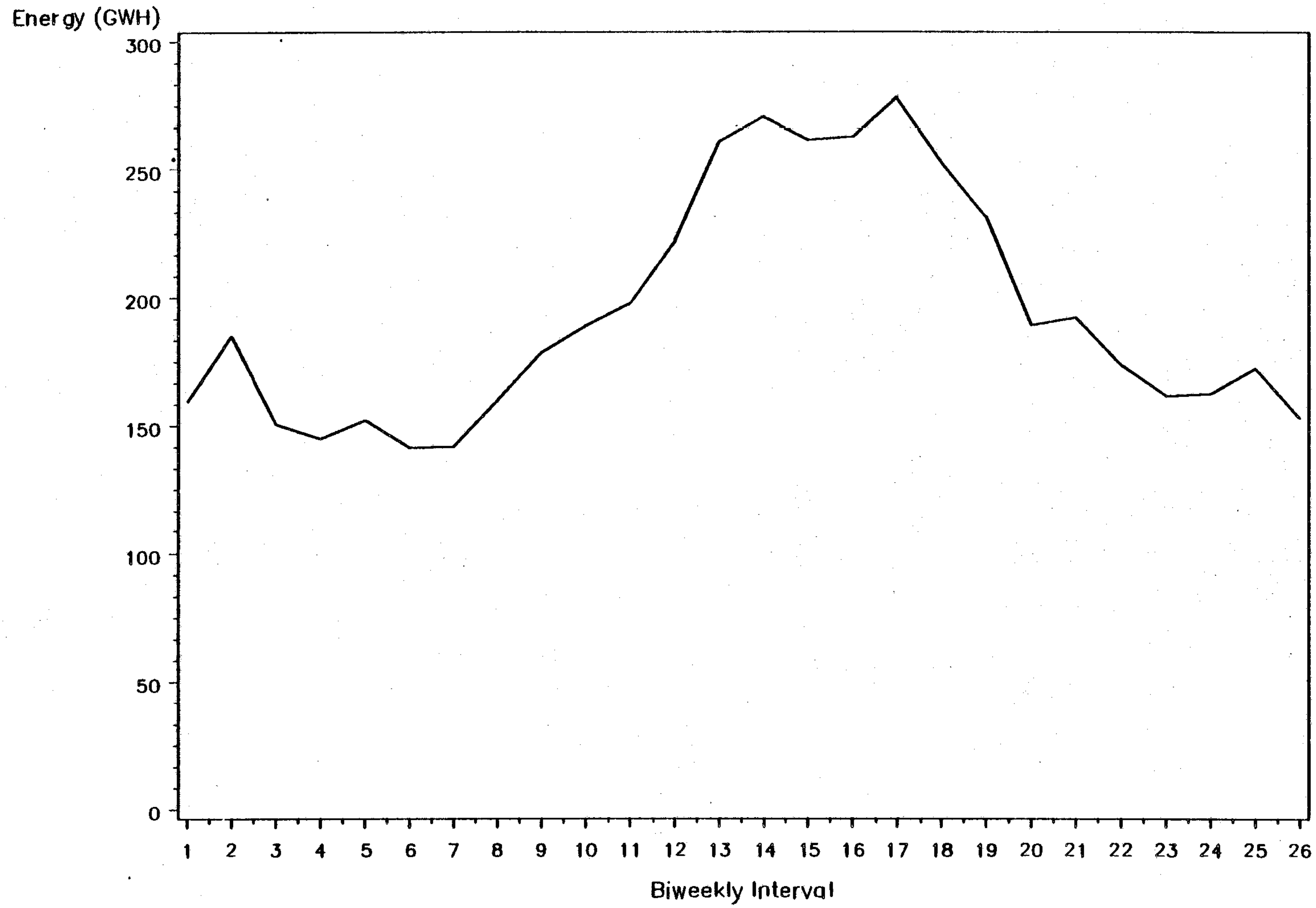


Figure 4.1-1 1990 Generation Requirements by Biweekly Interval: COA

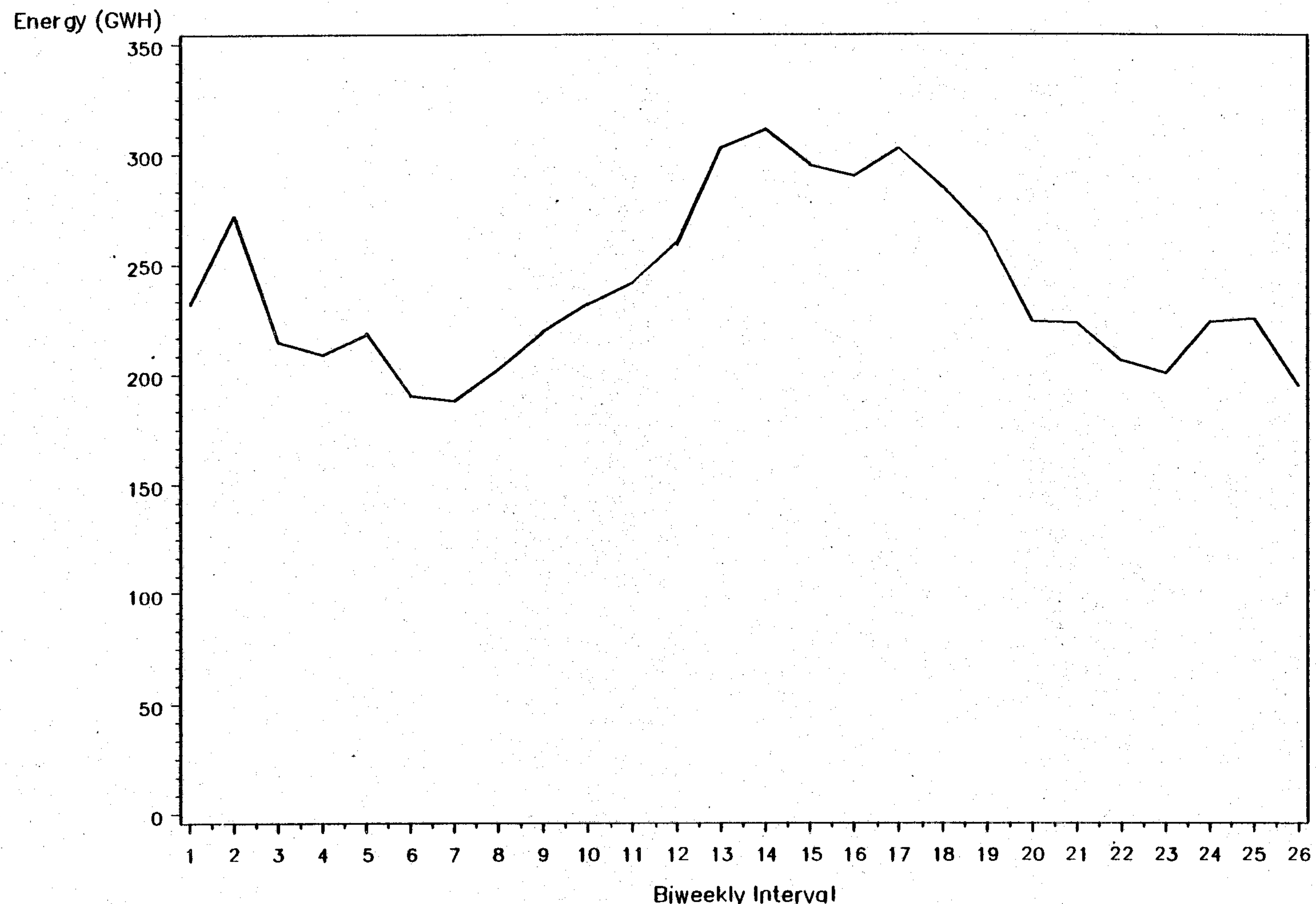


Figure 4.1-2 1990 Generation Requirements by Biweekly Interval: LCRA

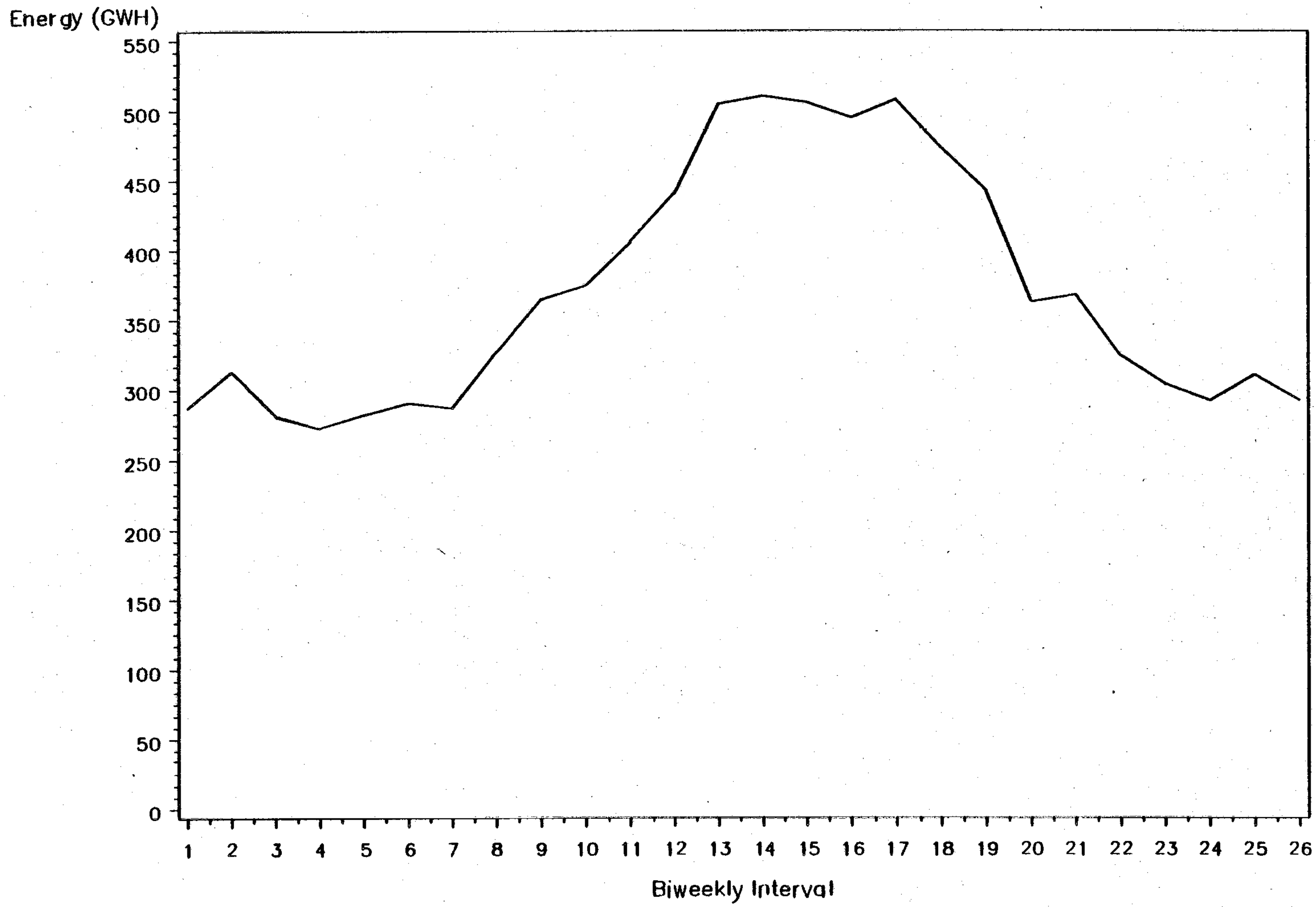


Figure 4.1-3 1990 Generation Requirements by Biweekly Interval: CPSB

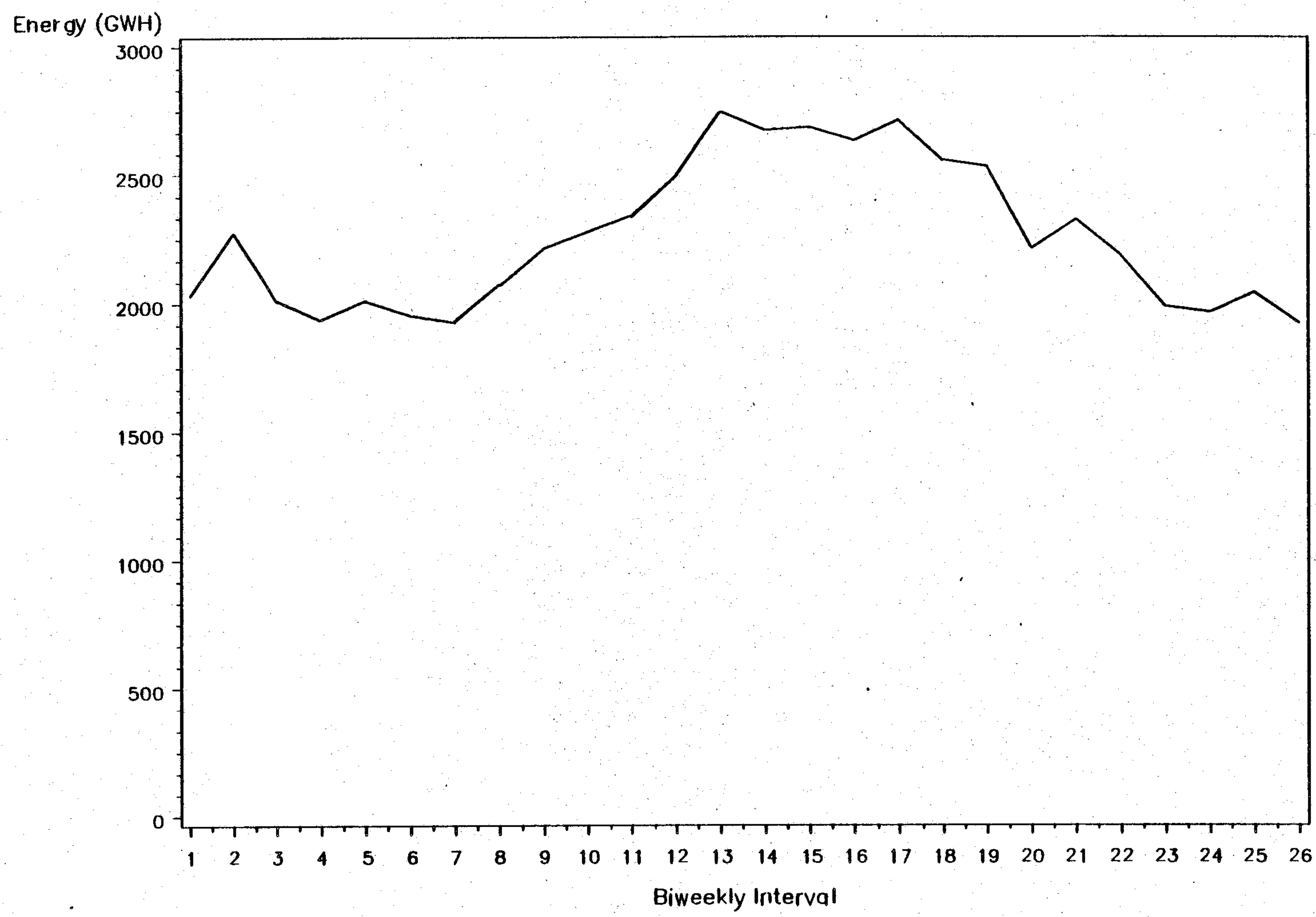


Figure 4.1-4 1990 Generation Requirements by Biweekly Interval: HL&P

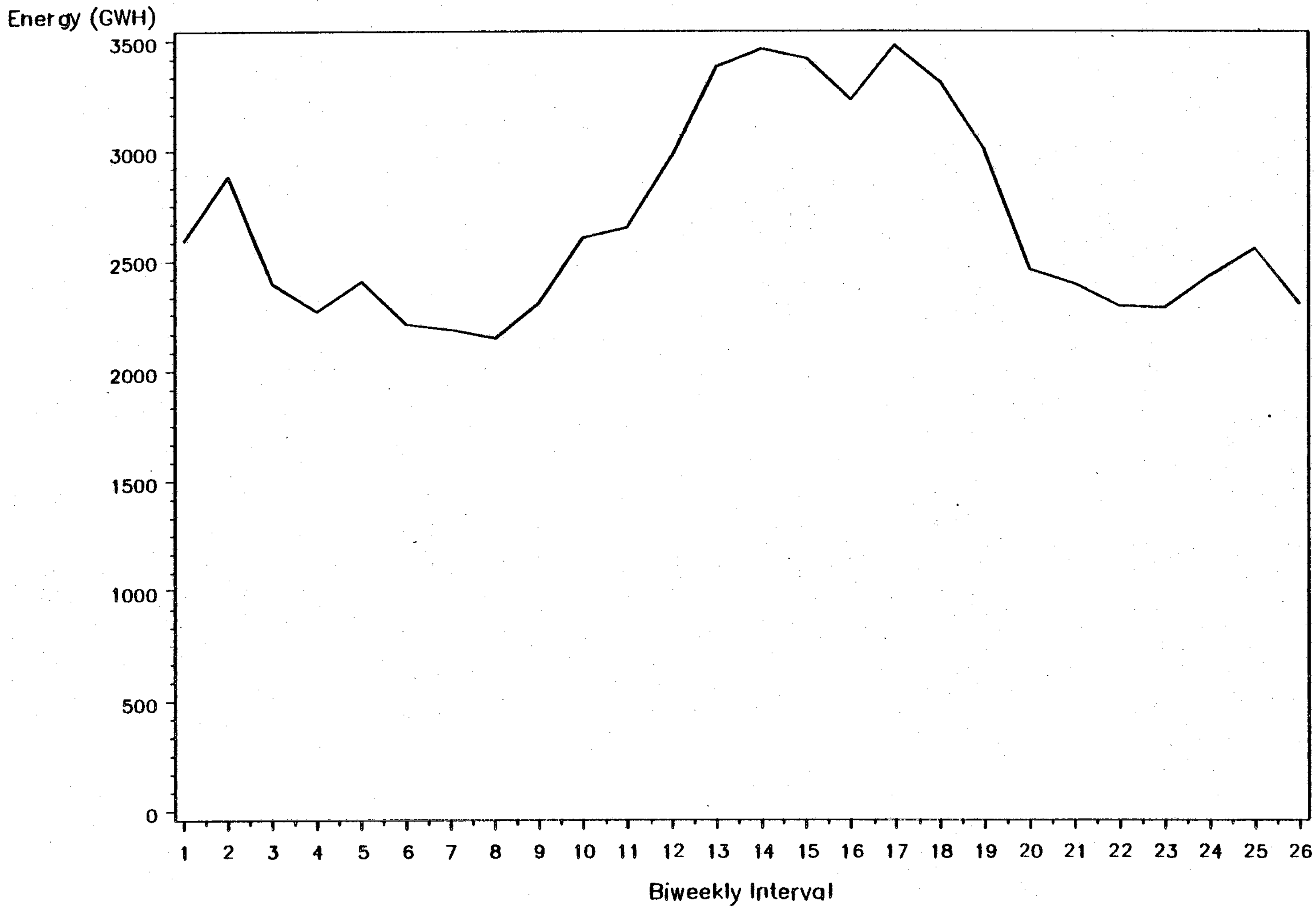


Figure 4.1-5 1990 Generation Requirements by Biweekly Interval: TUEC

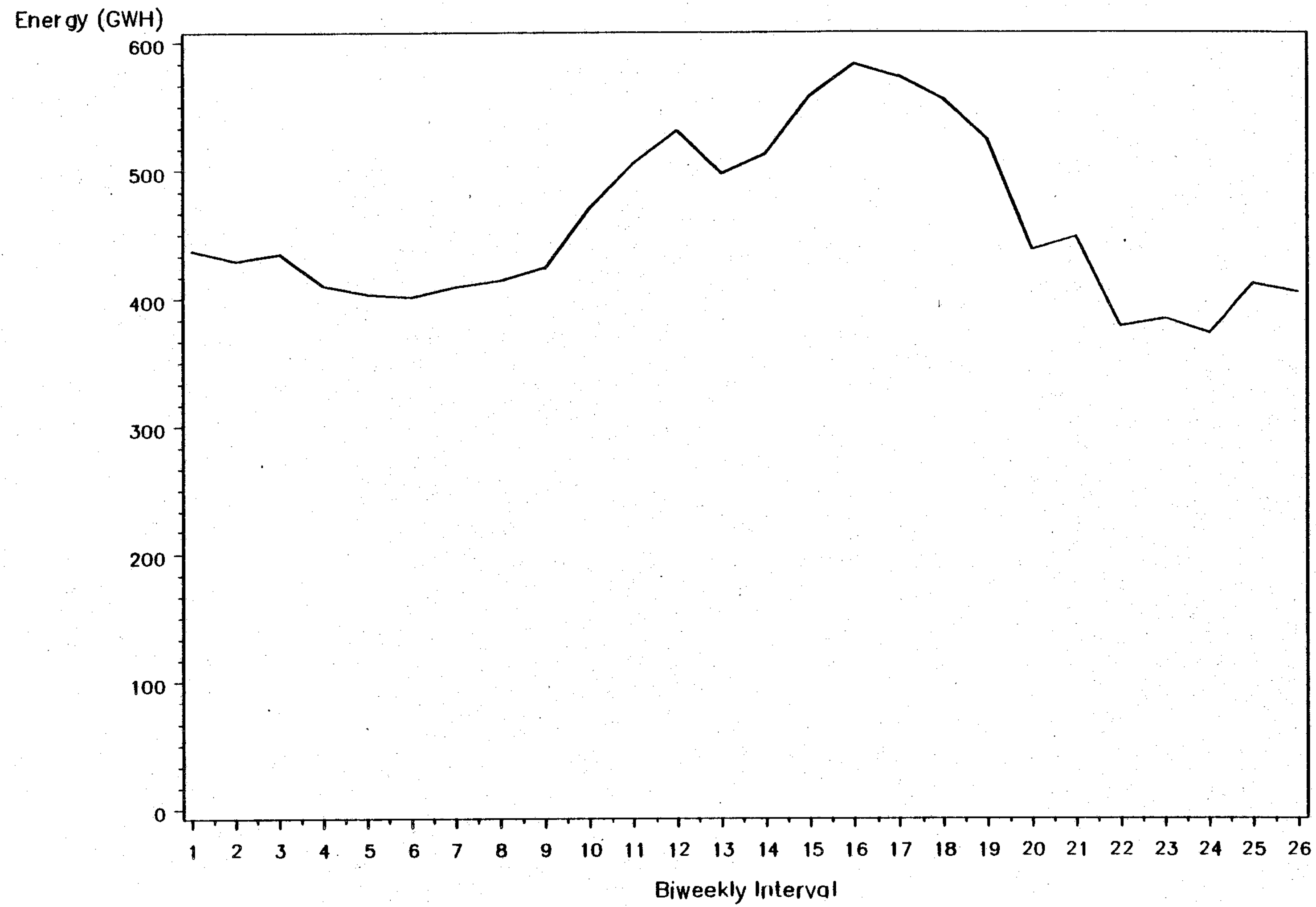


Figure 4.1-6 1990 Generation Requirements by Biweekly Interval: CP&L

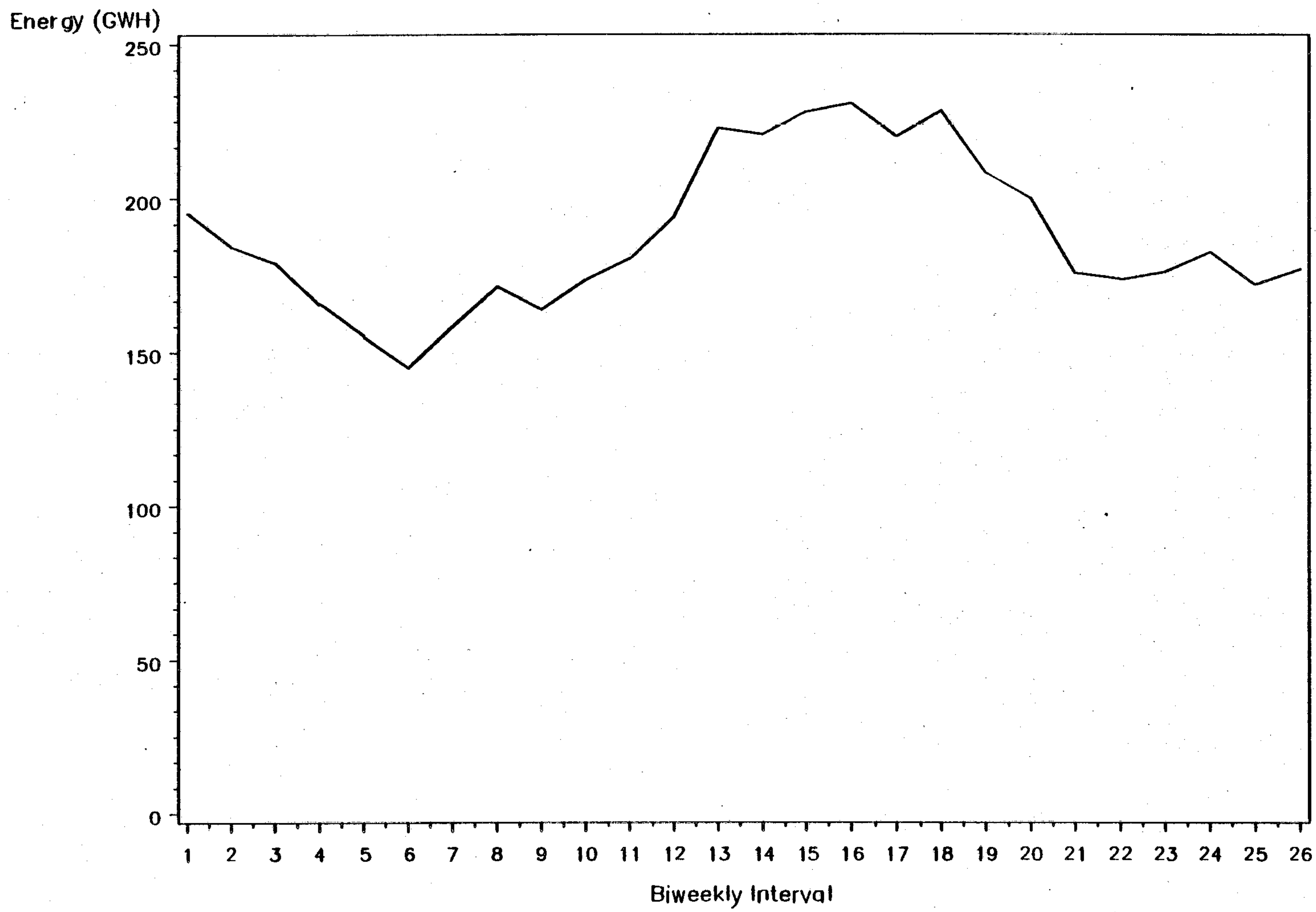


Figure 4.1-7 1990 Generation Requirements by Biweekly Interval: WTU

The general shapes of the graphs are similar. The generation requirements of all utilities peak during the summer between intervals 13 through 19. The exact interval in which the annual peak occurs varies from company to company but the demand stays approximately the same during these intervals. Low demand occurs during the spring between intervals 5 through 8 and during the fall between intervals 22 through 24.

Figures 4.1-8 through 4.1-14 show the biweekly peak and valley megawatt loads for the seven utilities. These figures are derived from the same historical data as Figures 4.1-1 through 4.1-7. While Figures 4.1-1 through 4.1-7 show the amount of energy that needs to be delivered, Figures 4.1-8 through 4.1-14 show the capacity resources needed to produce that energy.

The peak load is the highest load in the interval, and the valley load is the lowest load in the interval. The interval peak usually occurs in the weekday afternoon while the interval valley usually occurs during the weekend night. The valley load represents that part of demand that is less weather sensitive, such as lighting and some industrial activities. The peak load is associated with weather and residential and commercial activities. The difference between peak and valley load indicates the swing in load during the biweekly period. Seasonally, both peak and valley load reach the highest point during summer and are the lowest during spring and fall. This characteristic is typical in Texas and other sunbelt states where air conditioning systems are needed to control the indoor climate. The winter load falls somewhere between the summer and spring/fall load although LCRA is an exception. The peak load for LCRA during the winter is approximately the same as peak load during summer. Although the valley load is also higher during the summer and winter than during the spring and fall, it does not fluctuate as much as the peak load.

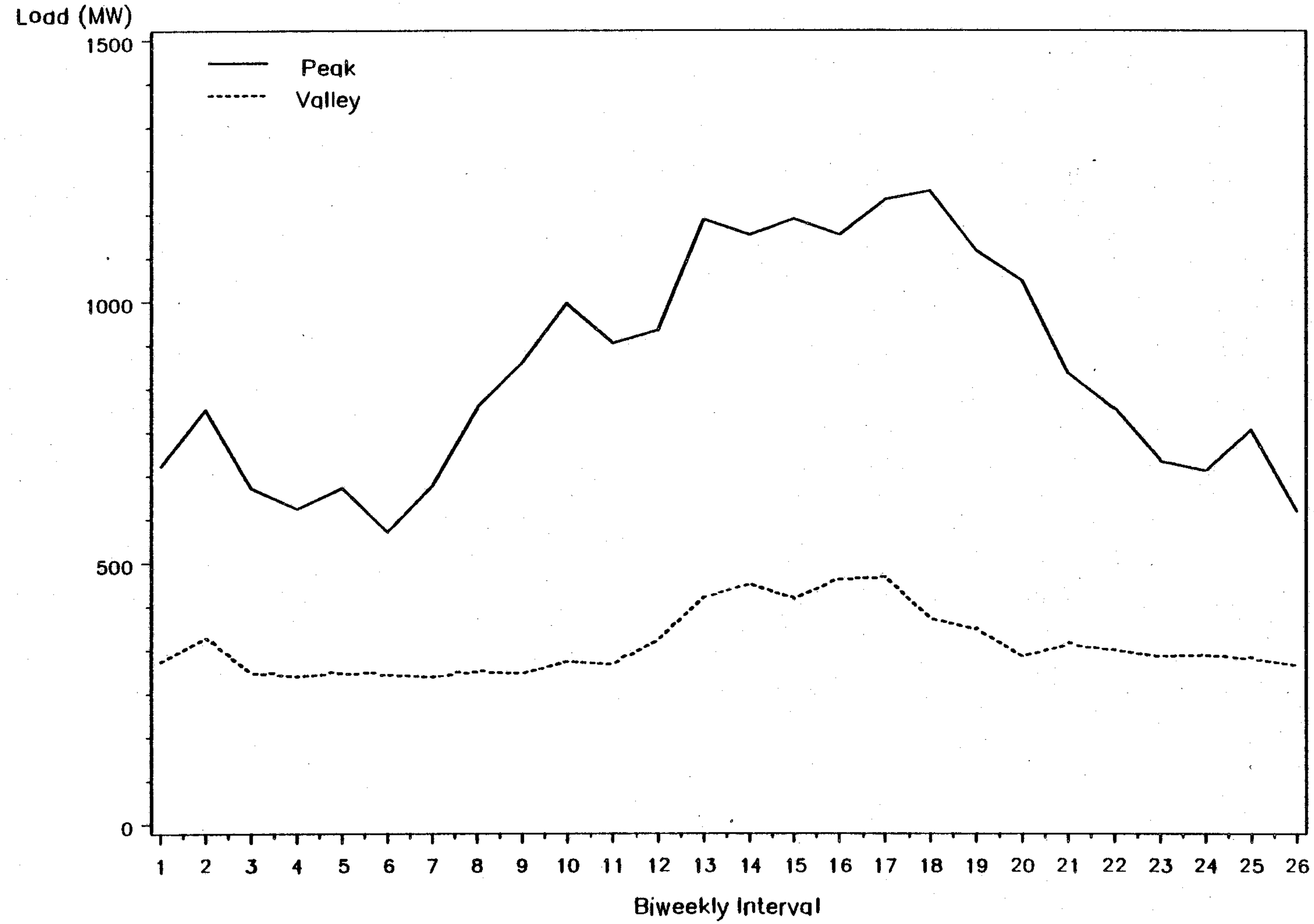


Figure 4.1-8 1990 Peak and Valley Load by Biweekly Inverval: COA

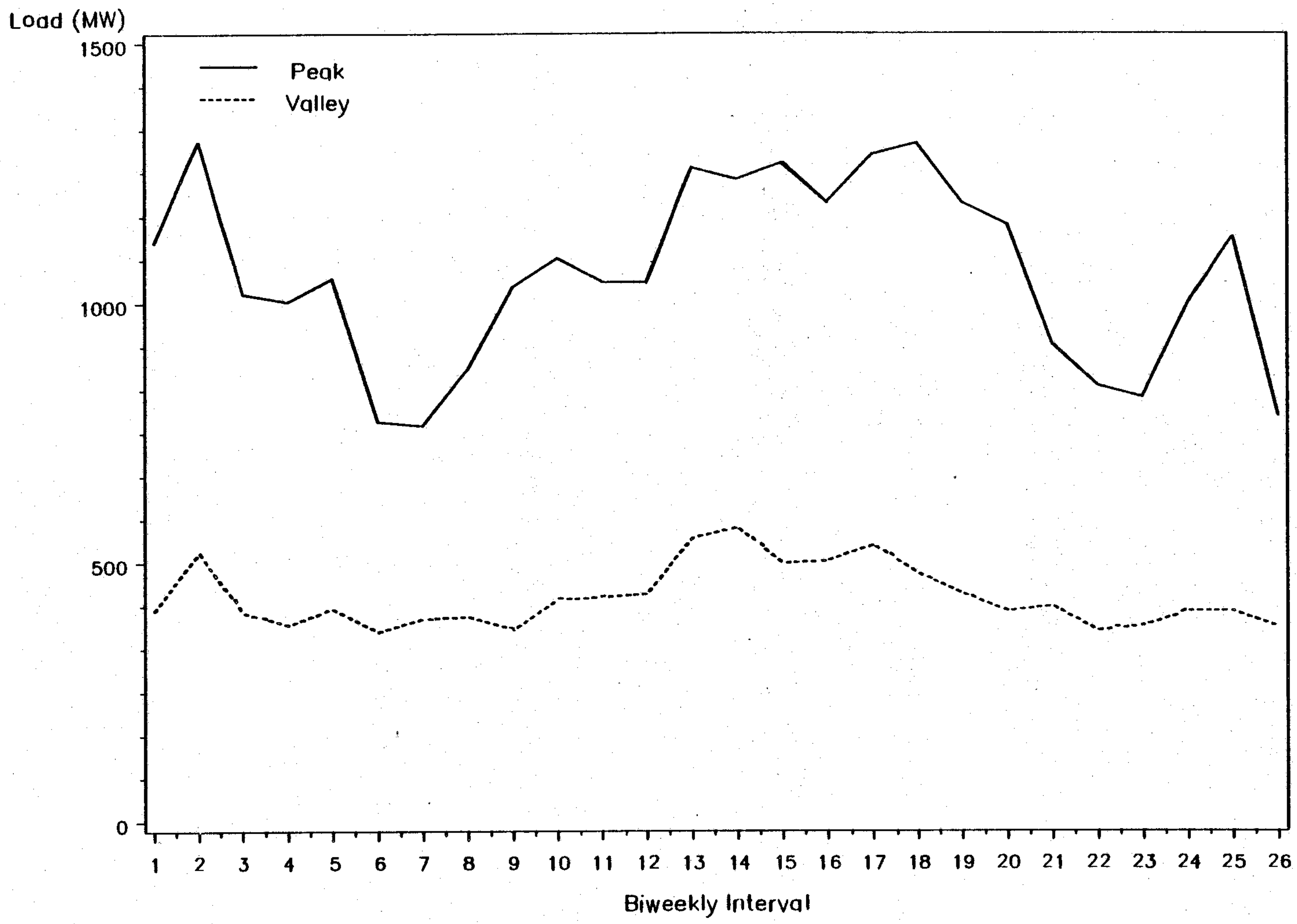


Figure 4.1-9 1990 Peak and Valley Load by Biweekly Inverval: LCRA

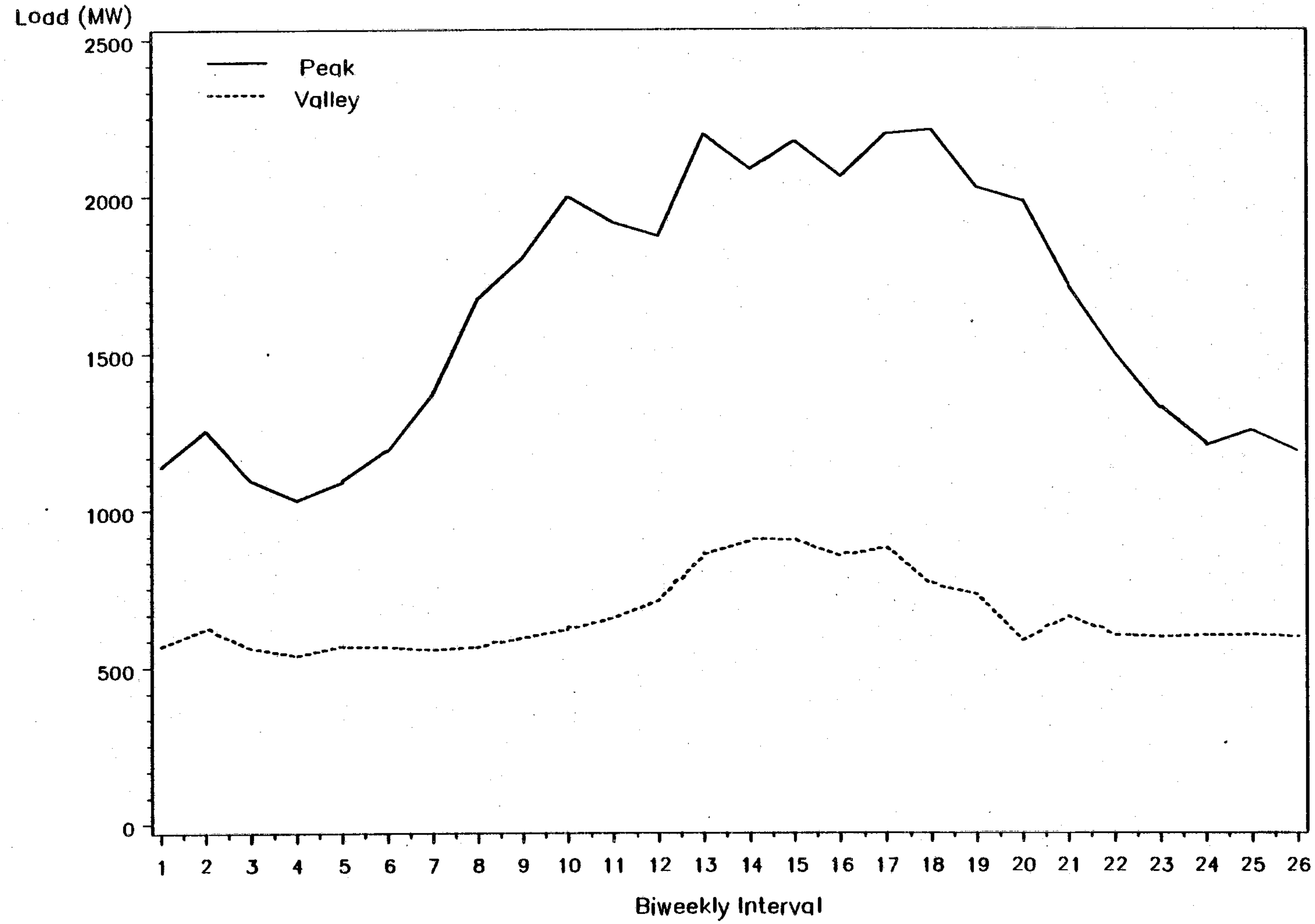


Figure 4.1-10 1990 Peak and Valley Load by Biweekly Inverval: CPSB

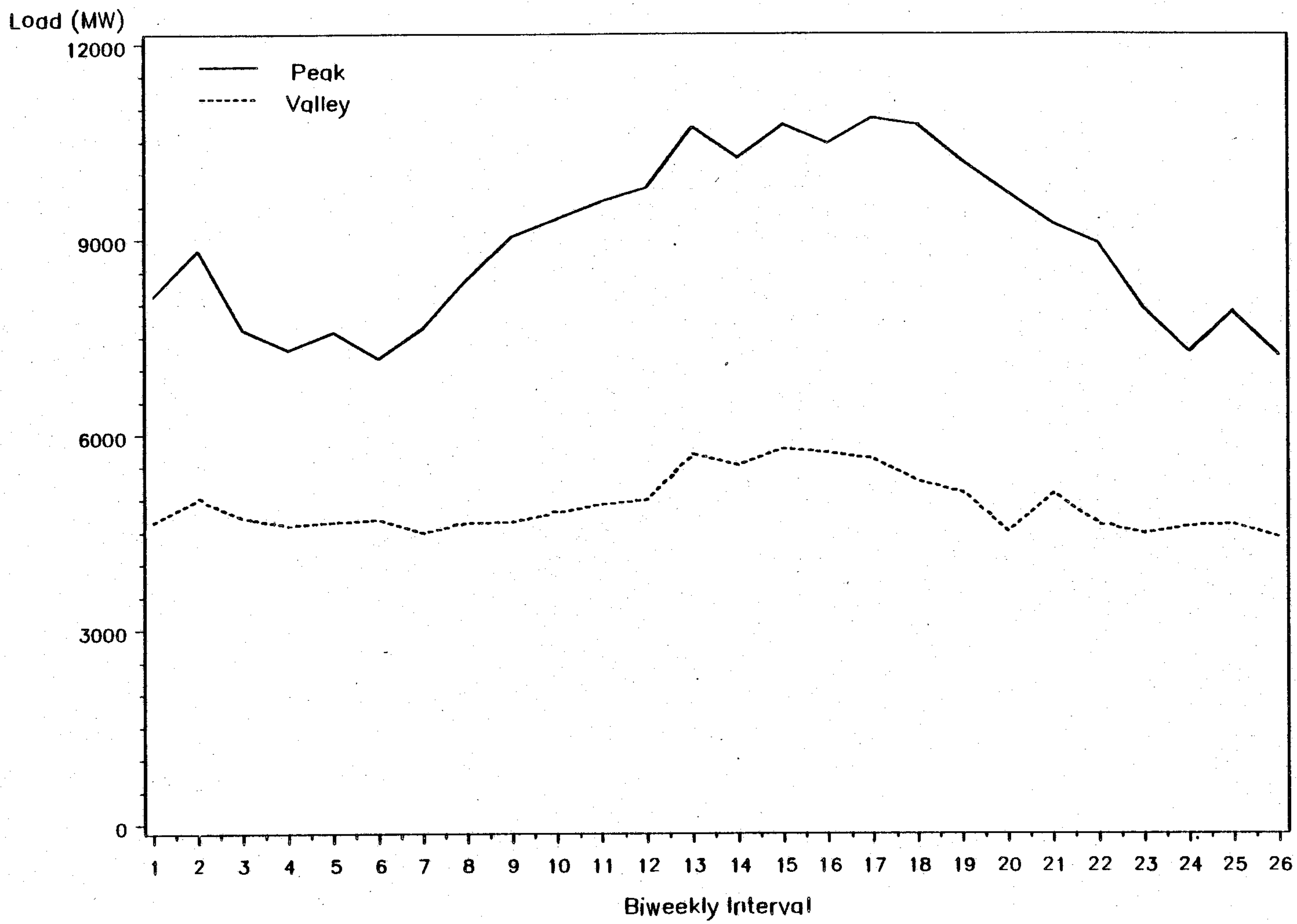


Figure 4.1-11 1990 Peak and Valley Load by Biweekly Inverval: HL&P

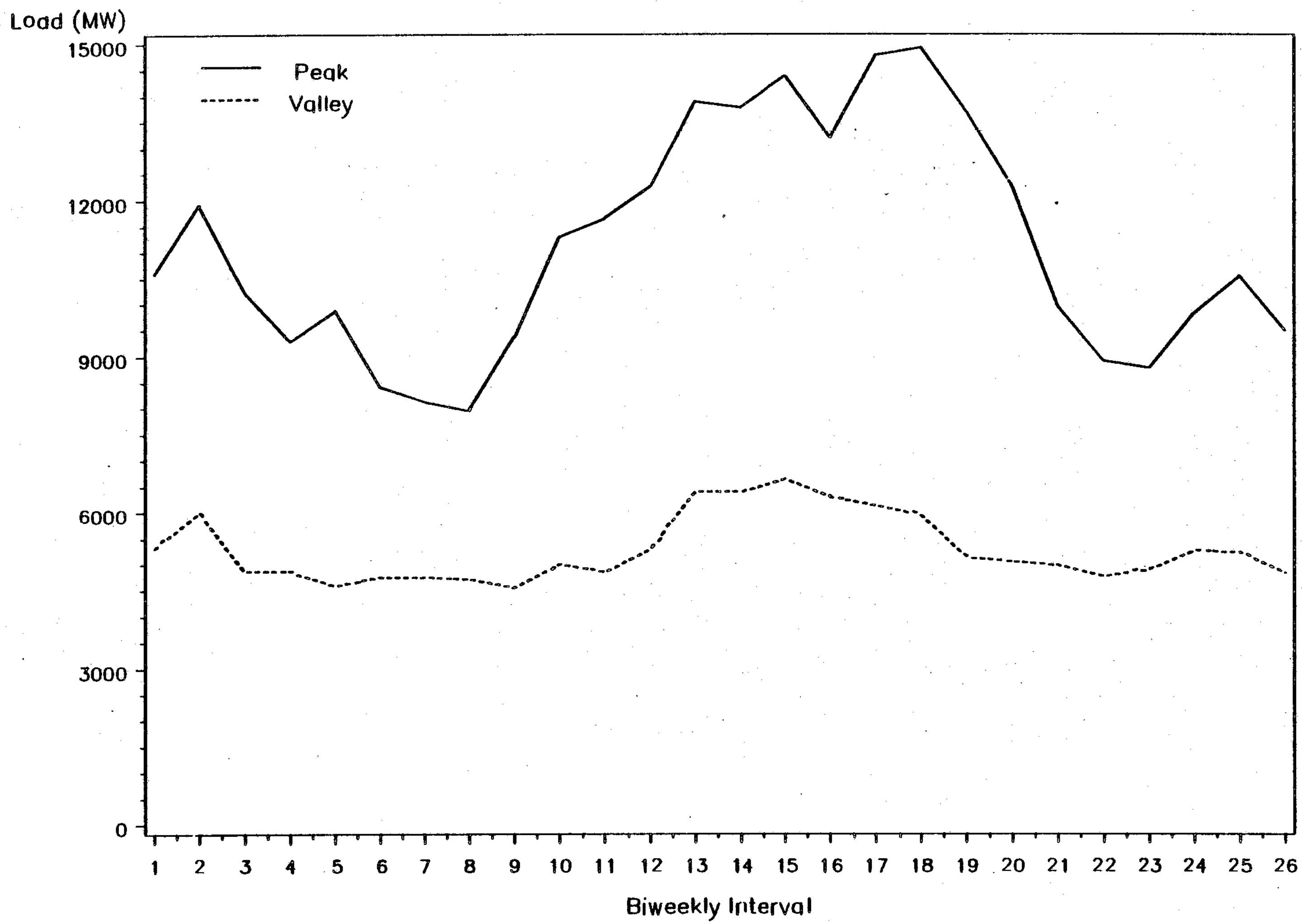


Figure 4.1-12 1990 Peak and Valley Load by Biweekly Inverval: TUEC

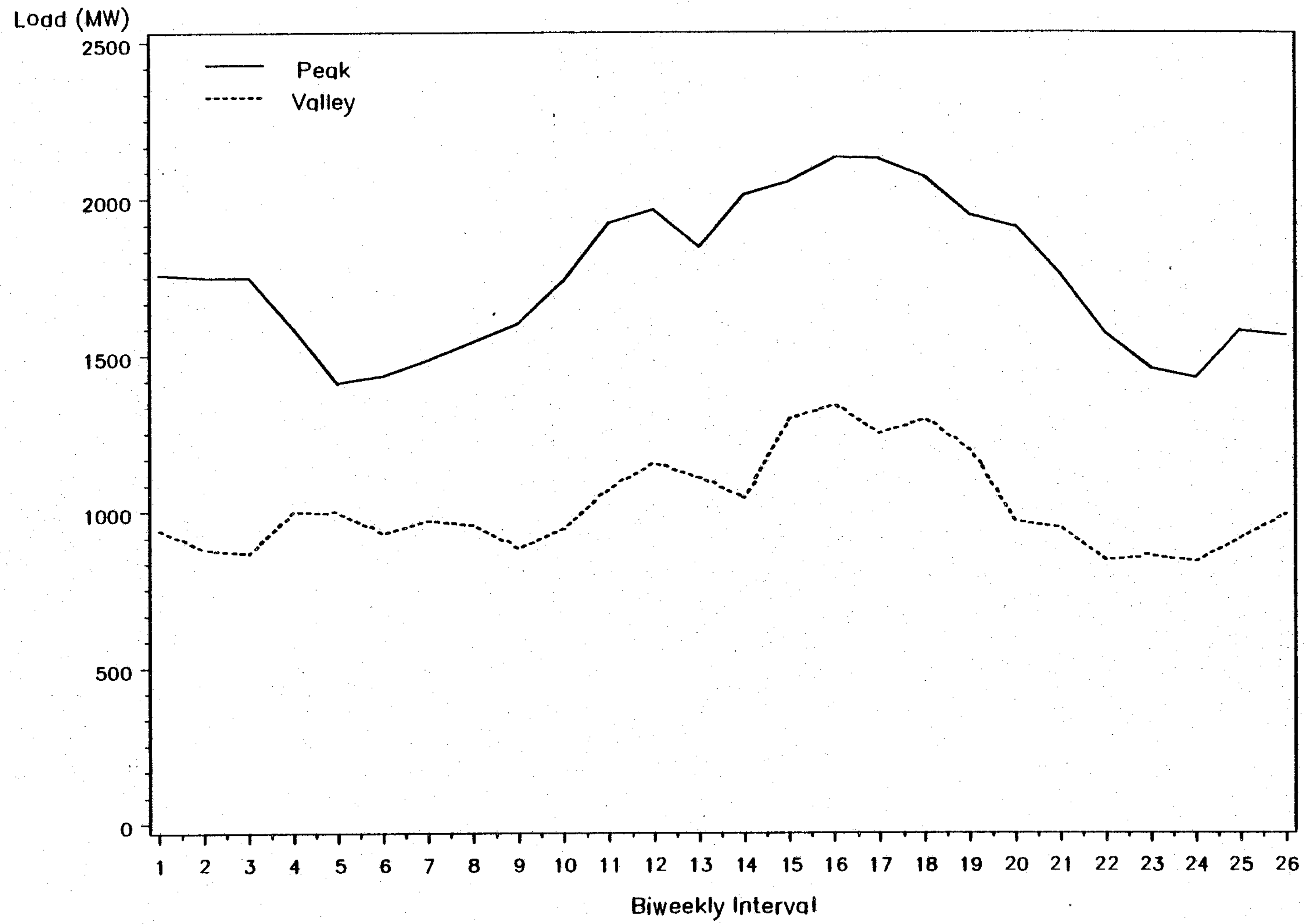


Figure 4.1-13 1990 Peak and Valley Load by Biweekly Inverval: CP&L

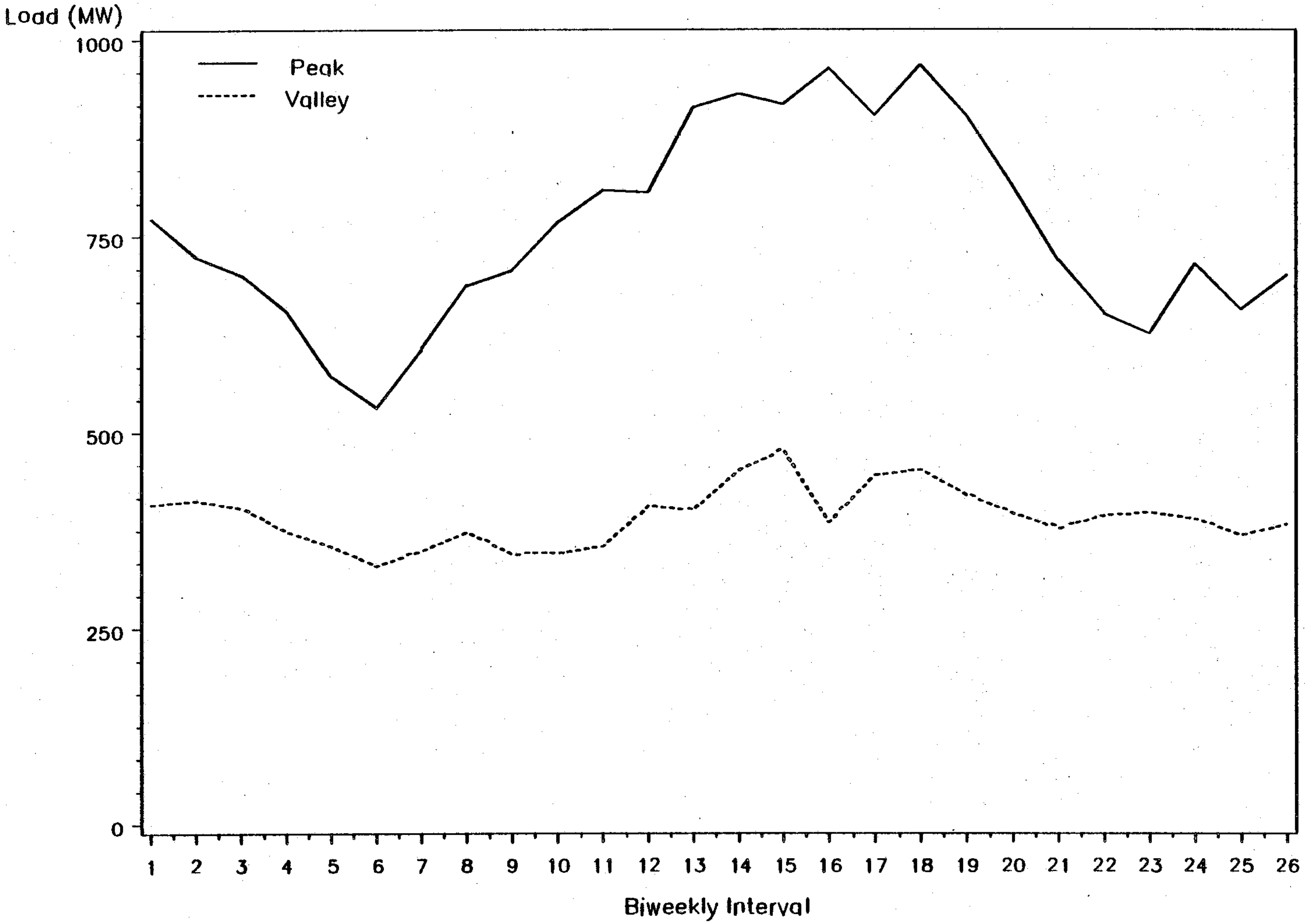


Figure 4.1-14 1990 Peak and Valley Load by Biweekly Inverval: WTU

Both generation requirements graphs in Figures 4.1-1 through 4.1-7 and peak and valley load demand graphs in Figures 4.1-8 through 4.1-14 show that even though the demand follows the same trend for all the utilities, the interval-to-interval fluctuations differ among utilities. For example, between intervals 6 and 8, the peak load of TUEC is decreasing while the peak load of HL&P is increasing. Although not shown in the figures, similar situations also occur on a daily or even hourly basis. The load variations make it impossible for all the utilities to operate at the same efficiency at all times although they can average about the same annually. At any instant, some utilities will have higher while others will have lower than average marginal costs for the entire system.

4.1.9 Capacity Reserves

Tables 4.1-4 through 4.1-15 (six tables for each forecast study year) show the capacity reserves by interval for the seven utilities during 1990 and 1995 as calculated by the MAPS/MWFLOW software. WTU and CPL are reported as a single company under C&SW which is the name of their holding company.

The tables show installed capacities and system reserves versus modified peaks for each biweekly interval. Modified peaks are peak loads which are reduced by subtracting the generation from pondage units which have prescheduled output. The installed capacities shown in the tables reflect only thermal units over which operators are assumed to have full control during economic dispatch.

The peak load column provides some indications of the characteristics of demand. Except for LCRA, all of the systems' annual peak demands are summer peaks. In LCRA, winter and summer peaks are about equal and occur in intervals 2 and 18, respectively. LCRA has been experiencing high peak demand during winter and is

TABLE 4.1-4

1990 Peak Demand and Reserve Capacity by Biweekly Interval:
City of Austin

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	911.6	2541.0	147.0	162.6	218.0	138.7
2	1071.0	2541.0	146.9	123.5	400.0	86.2
3	849.6	2541.0	510.0	139.0	11.1	137.7
4	792.0	2541.0	709.8	131.2	3.6	130.7
5	851.1	2541.0	800.0	104.6	19.4	102.3
6	725.6	2541.0	1181.8	87.3	205.0	59.1
7	857.0	2541.0	946.7	86.0	414.0	37.7
8	1074.0	2541.0	364.9	102.6	513.4	54.8
9	1199.4	2541.0	0.0	111.9	198.0	95.3
10	1369.2	2541.0	0.0	85.6	98.0	78.4
11	1260.0	2541.0	0.0	101.7	485.0	63.2
12	1296.9	2541.0	0.0	95.9	19.4	94.4
13	1609.8	2541.0	0.0	57.8	280.0	40.5
14	1565.5	2541.0	0.0	62.3	234.2	47.4
15	1611.2	2541.0	0.0	57.7	0.0	57.7
16	1565.5	2541.0	0.0	62.3	0.0	62.3
17	1662.9	2541.0	0.0	52.8	97.0	47.0
18	1688.0	2541.0	0.0	50.5	282.2	33.8
19	1521.2	2541.0	0.0	67.0	181.0	55.1
20	1435.6	2541.0	0.0	77.0	21.0	75.5
21	1174.3	2541.0	0.0	116.4	3.6	16.1
22	1074.0	2541.0	32.0	133.6	532.0	84.1
23	926.4	2541.0	519.0	118.3	0.0	118.3
24	899.8	2541.0	486.7	128.3	295.0	95.5
25	1012.0	2541.0	239.0	127.5	218.0	105.9
26	784.7	2541.0	217.9	196.1	285.0	159.7

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-5

1990 Peak Demand and Reserve Capacity by Biweekly Interval:
Lower Colorado River Authority

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	1103.1	2012.0	0.0	82.4	425.0	43.9
2	1329.0	2012.0	0.0	51.4	0.0	51.4
3	991.3	2012.0	425.0	60.1	0.0	60.1
4	972.9	2012.0	425.0	63.1	0.0	63.1
5	1024.7	2012.0	425.0	54.9	0.0	54.9
6	760.1	2012.0	845.0	53.5	330.0	10.1
7	717.6	2012.0	844.8	62.7	0.0	62.7
8	823.0	2012.0	560.0	76.4	182.4	54.3
9	995.6	2012.0	552.3	46.6	0.0	46.6
10	1044.7	2012.0	551.7	39.8	66.0	33.5
11	998.2	2012.0	135.0	88.0	420.0	46.0
12	1075.6	2012.0	0.1	87.0	417.0	48.3
13	1303.2	2012.0	0.0	54.4	417.0	22.4
14	1369.1	2012.0	0.0	47.0	135.0	37.1
15	1340.5	2012.0	0.0	50.1	415.0	19.1
16	1240.1	2012.0	0.0	62.3	0.0	62.3
17	1310.2	2012.0	0.0	53.6	0.0	53.6
18	1320.9	2012.0	0.0	52.3	182.4	38.5
19	1191.8	2012.0	0.0	68.8	54.0	64.3
20	1143.4	2012.0	465.0	35.3	0.0	35.3
21	877.2	2012.0	465.0	76.4	0.0	76.4
22	806.3	2012.0	465.0	91.9	285.0	56.5
23	812.7	2012.0	750.0	55.3	0.0	55.3
24	970.6	2012.0	749.8	30.0	420.0	-13.2
25	1116.9	2012.0	465.0	38.5	266.9	14.6
26	830.6	2012.0	0.4	142.2	845.0	40.5

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-6

1990 Peak Demand and Reserve Capacity by Biweekly Interval:
City Public Service Board of San Antonio

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	1530.1	3900.0	360.0	131.4	350.0	108.5
2	1687.5	3900.0	420.4	106.2	350.0	85.5
3	1469.5	3900.0	890.1	104.8	0.0	104.8
4	1387.4	3936.0	1245.1	93.9	189.0	80.3
5	1465.5	3936.0	1320.1	78.5	36.0	76.0
6	1596.0	3936.0	1122.6	76.3	0.0	76.3
7	1842.3	3936.0	810.0	69.7	516.0	41.7
8	2252.7	3936.0	349.9	59.2	676.0	29.2
9	2425.0	3936.0	0.0	62.3	811.5	28.8
10	2687.4	3936.0	0.0	46.5	0.0	46.5
11	2577.0	3936.0	0.0	52.7	371.6	38.3
12	2519.2	3936.0	0.0	56.2	91.1	52.6
13	2952.5	3936.0	0.0	33.3	350.0	21.5
14	2807.1	3936.0	0.0	40.2	458.3	23.9
15	2925.6	3936.0	0.0	34.5	39.8	33.2
16	2774.8	3936.0	0.0	41.8	160.0	36.1
17	2955.2	3936.0	0.0	33.2	0.0	33.2
18	2974.0	3936.0	0.0	32.3	96.0	29.1
19	2725.0	3936.0	0.0	44.4	91.1	41.1
20	2667.2	3936.0	0.0	47.6	184.2	40.7
21	2305.2	3936.0	0.0	70.7	405.0	53.2
22	2019.9	3936.0	0.0	94.9	462.7	72.0
23	1780.4	3936.0	400.0	98.6	0.0	98.6
24	1621.6	3936.0	232.5	128.4	0.0	128.4
25	1686.2	3936.0	505.0	103.5	816.7	55.0
26	1597.3	3936.0	235.1	131.7	160.0	121.7

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-7

1990 Peak Demand and Reserve Capacity by Biweekly Interval:
Houston Lighting & Power

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	7637.4	14815.0	2058.0	67.0	2430.1	35.2
2	8300.1	14815.0	2057.8	53.7	3146.5	15.8
3	7153.9	14815.0	2915.0	66.3	1079.2	51.3
4	6874.0	14815.0	4017.9	57.1	1111.2	40.9
5	7129.3	14815.0	3325.0	61.2	2122.3	31.4
6	6797.8	14815.0	3876.1	60.9	1678.8	36.2
7	7172.0	14815.0	3875.1	52.5	1088.5	37.4
8	7885.5	14815.0	2214.7	59.8	383.4	54.9
9	8496.6	14815.0	1510.3	56.6	892.2	46.1
10	9156.6	14815.0	959.0	51.3	2821.1	20.5
11	9001.4	14815.0	750.0	56.3	1536.6	39.2
12	9197.9	14815.0	590.5	54.6	2802.1	24.2
13	10070.3	14815.0	0.0	47.1	1213.5	35.1
14	9629.4	14815.0	0.0	53.9	1133.9	42.1
15	10101.3	14815.0	0.0	46.7	23.5	46.4
16	9836.2	14815.0	0.0	50.6	1234.1	38.1
17	10201.0	14815.0	0.0	45.2	1035.4	35.1
18	10104.2	14815.0	0.0	46.6	1402.9	32.7
19	9579.6	14815.0	406.0	50.4	1686.2	32.8
20	9123.6	14815.0	406.0	57.9	1981.5	36.2
21	8674.3	14815.0	1316.0	55.6	1242.7	41.3
22	8390.4	14815.0	1315.5	60.9	2860.4	26.8
23	7444.6	14815.0	3131.0	56.9	1711.8	34.0
24	6857.0	14815.0	2424.5	80.7	812.0	68.9
25	7392.0	14815.0	3412.0	54.3	2815.3	16.2
26	6826.5	14815.0	2455.1	81.1	295.3	76.7

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-8

1990 Peak Demand and Reserve Capacity by Biweekly Interval:
Texas Utilities Electric Company

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	12751.5	21047.0	1303.0	54.8	3093.6	30.6
2	14340.8	21047.0	1303.0	37.7	1587.6	26.6
3	12315.0	21047.0	2973.0	46.8	2093.3	29.8
4	11196.0	21047.0	3170.2	59.7	3349.1	29.8
5	11907.4	21437.0	3655.0	49.3	2996.1	24.2
6	10143.3	21437.0	5185.4	60.2	2363.0	36.9
7	9797.2	21437.0	5430.2	63.4	1142.3	51.7
8	9580.2	21437.0	5994.8	61.2	3036.8	29.5
9	11272.0	21437.0	3548.8	58.7	3389.5	28.6
10	13624.5	21437.0	2327.4	40.3	2904.7	18.9
11	14039.3	21437.0	1350.9	43.1	3023.5	21.5
12	14759.2	21437.0	317.1	43.1	3744.4	17.7
13	16742.7	21437.0	0.0	28.0	1106.1	21.4
14	16612.5	21437.0	0.0	29.0	2118.8	16.3
15	17346.9	21437.0	0.0	23.6	1271.6	16.2
16	15905.9	21437.0	0.0	34.8	2431.6	19.5
17	17815.9	21437.0	0.0	20.3	2100.7	8.5
18	17998.0	21437.0	0.0	19.1	2663.0	4.3
19	16506.4	21437.0	0.0	29.9	3163.1	10.7
20	14778.5	21437.0	925.0	38.8	2682.1	20.6
21	11995.5	21437.0	3945.0	45.8	1512.4	33.2
22	10737.8	21437.0	3668.4	65.5	471.3	61.1
23	10576.2	21437.0	5358.2	52.0	2045.0	32.7
24	11854.4	21437.0	3762.0	49.1	2164.5	30.8
25	12711.7	21437.0	4498.0	33.3	3681.4	4.3
26	11443.2	21198.0	1709.2	70.3	2520.7	48.3

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-9

1990 Peak Demand and Reserve Capacity by Biweekly Interval:
Central & Southwest Company

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	3503.3	6063.0	865.0	48.4	824.1	24.9
2	3228.0	6063.0	1205.0	50.5	315.0	40.7
3	3322.7	6063.0	1520.0	36.7	74.4	34.5
4	2948.1	6063.0	2472.8	21.8	0.0	21.8
5	2921.1	6063.0	2214.5	31.7	938.8	-0.4
6	2809.2	6063.0	2495.0	27.0	40.6	25.6
7	2899.4	6063.0	2053.4	38.3	127.6	33.9
8	3461.3	6063.0	1398.2	34.8	98.3	31.9
9	3304.5	6063.0	1082.9	50.7	312.2	41.3
10	3796.8	6063.0	969.9	34.1	27.2	33.4
11	4153.3	6063.0	312.7	38.5	1693.7	-2.3
12	4355.1	6063.0	230.0	33.9	225.5	28.8
13	4461.0	6063.0	75.1	34.2	469.3	23.7
14	4367.5	6063.0	75.0	37.1	311.9	30.0
15	4425.1	6063.0	74.9	35.3	63.2	33.9
16	4930.6	6063.0	0.0	23.0	549.5	11.8
17	4917.5	6063.0	0.0	23.3	300.7	17.2
18	4688.1	6063.0	0.0	29.3	505.2	18.6
19	4525.4	6063.0	0.0	34.0	785.8	16.6
20	4019.6	6063.0	543.0	37.3	79.3	35.4
21	3565.4	6063.0	543.0	54.8	583.4	38.5
22	3113.5	6063.0	1718.0	39.6	336.3	28.8
23	2939.3	6063.0	2060.0	36.2	127.4	31.9
24	2882.9	6063.0	2060.0	38.9	141.0	34.0
25	2990.6	6063.0	1657.3	47.3	315.0	36.8
26	3243.5	6063.0	563.1	69.6	176.7	64.1

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-10

1995 Peak Demand and Reserve Capacity by Biweekly Interval:
City of Austin

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	1191.4	2705.0	165.0	113.2	508.0	70.6
2	1395.0	2705.0	164.9	82.1	447.2	50.0
3	1112.2	2705.0	607.0	88.6	0.0	88.6
4	1038.7	2705.0	806.8	82.7	289.2	54.9
5	1114.1	2705.0	800.0	71.0	23.6	68.9
6	953.9	2705.0	1265.8	50.9	0.0	50.9
7	1121.7	2677.0	962.7	52.8	200.0	35.0
8	1398.8	2677.0	296.9	70.2	200.0	55.9
9	1559.0	2677.0	0.0	71.7	200.0	58.9
10	1775.8	2677.0	0.0	50.7	0.0	50.7
11	1636.3	2677.0	0.0	63.6	0.0	63.6
12	1683.4	2677.0	0.0	59.0	203.4	46.9
13	2083.1	2677.0	0.0	28.5	97.0	23.9
14	2026.5	2677.0	0.0	32.1	144.1	25.0
15	2085.0	2677.0	0.0	28.4	200.0	18.8
16	2026.5	2677.0	0.0	32.1	381.0	13.3
17	2151.0	2677.0	0.0	24.5	591.0	-3.0
18	2183.0	2677.0	0.0	22.6	116.2	17.3
19	1970.0	2677.0	0.0	35.9	19.4	34.9
20	1860.6	2677.0	0.0	43.9	62.0	40.5
21	1527.0	2677.0	0.0	75.3	440.0	46.5
22	1398.8	2677.0	0.0	91.4	165.0	79.6
23	1210.3	2677.0	506.0	79.4	33.0	76.7
24	1176.3	2677.0	505.7	84.6	380.4	52.2
25	1319.6	2677.0	257.0	83.4	285.0	61.8
26	1029.3	2677.0	235.9	137.2	200.0	117.7

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-11

1995 Peak Demand and Reserve Capacity by Biweekly Interval:
Lower Colorado River Authority

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	1434.8	2012.0	0.0	40.2	27.0	38.3
2	1719.0	2012.0	0.0	17.1	0.0	17.0
3	1294.1	2012.0	330.0	30.0	0.0	30.0
4	1270.9	2012.0	330.0	32.3	285.0	9.9
5	1336.2	2012.0	330.0	25.9	0.0	25.9
6	995.1	2012.0	750.0	26.8	417.0	-15.1
7	948.8	2012.0	749.8	33.0	0.0	33.0
8	1082.4	2012.0	465.0	42.9	401.9	5.8
9	1302.3	2012.0	135.3	44.1	417.0	12.1
10	1367.7	2012.0	135.0	37.2	0.0	37.2
11	1307.9	2012.0	135.0	43.5	0.0	43.5
12	1395.7	2012.0	0.1	44.2	512.4	7.4
13	1689.7	2012.0	0.0	19.1	85.0	14.0
14	1757.2	2412.0	0.0	37.3	427.0	13.0
15	1725.0	2412.0	0.0	39.8	560.0	7.4
16	1608.9	2412.0	0.0	49.9	425.0	23.5
17	1703.2	2412.0	0.0	41.6	1035.0	-19.2
18	1708.8	2412.0	135.0	33.2	380.0	11.0
19	1546.4	2412.0	135.0	47.2	135.0	38.5
20	1485.5	2412.0	560.0	24.7	0.0	24.7
21	1153.0	2412.0	560.0	60.6	0.0	60.6
22	1059.9	2412.0	560.0	74.7	0.0	74.7
23	1059.7	2412.0	845.0	47.9	66.0	41.6
24	1268.0	2412.0	709.9	34.2	182.4	19.8
25	1452.2	2412.0	842.0	8.1	285.0	-11.5
26	1071.9	2412.0	417.1	86.1	0.0	86.1

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-12

1995 Peak Demand and Reserve Capacity By Biweekly Interval:
City Public Service Board of San Antonio

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	1897.9	4932.0	441.0	136.6	602.5	104.9
2	2093.2	4932.0	700.6	102.1	0.0	102.1
3	1822.8	4932.0	1047.7	113.1	498.0	85.8
4	1721.0	4932.0	1598.2	93.7	210.7	81.5
5	1817.8	4932.0	1397.8	94.4	557.6	63.8
6	1979.7	4932.0	1365.0	80.2	534.0	53.2
7	2285.2	4932.0	902.8	76.3	36.0	74.7
8	2794.3	4932.0	349.9	64.0	1004.0	28.0
9	3008.0	4932.0	0.0	64.0	570.0	45.0
10	3333.5	4932.0	0.0	48.0	682.2	27.5
11	3196.6	4932.0	0.0	54.3	36.0	53.2
12	3124.8	4932.0	0.0	57.8	537.9	40.6
13	3662.3	4932.0	0.0	34.7	251.1	27.8
14	3482.0	4932.0	0.0	41.6	39.8	40.5
15	3628.9	4932.0	0.0	35.9	410.0	24.6
16	3442.0	4932.0	0.0	43.3	350.0	33.1
17	3665.6	4932.0	0.0	34.5	189.0	29.4
18	3689.0	4932.0	0.0	33.7	492.0	20.4
19	3380.2	4932.0	0.0	45.9	0.0	45.9
20	3308.4	4932.0	0.0	49.1	498.0	34.0
21	2859.4	4932.0	0.0	72.5	770.0	45.6
22	2505.5	4932.0	0.0	96.8	0.0	96.8
23	2208.4	4932.0	640.0	94.4	942.8	51.7
24	2011.4	4932.0	352.6	127.7	880.5	83.9
25	2091.5	4932.0	760.0	99.5	251.1	87.5
26	1981.4	4932.0	362.7	130.6	350.0	112.9

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-13

1995 Peak Demand and Reserve Capacity by Biweekly Interval:
Houston Lighting & Power

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	8386.0	15290.0	2087.0	57.4	2632.9	26.0
2	9113.8	15290.0	2087.0	44.9	1496.4	28.4
3	7857.3	15290.0	3222.0	53.6	1785.5	30.9
4	7555.1	15290.0	4104.6	48.1	1715.1	25.4
5	7832.0	15290.0	3891.0	45.5	471.5	39.5
6	7473.3	15290.0	4442.1	45.2	1711.0	22.3
7	7875.1	15290.0	3691.5	47.3	139.9	45.5
8	8658.6	15290.0	2720.5	45.2	1215.1	31.1
9	9329.5	15290.0	1549.3	47.3	3063.5	14.4
10	10054.2	15290.0	998.0	42.2	775.5	34.4
11	9883.8	15290.0	1173.2	42.8	1567.2	27.0
12	10099.6	15290.0	549.0	46.0	1933.6	26.8
13	11057.5	15290.0	0.0	38.3	4069.5	1.5
14	10573.4	15290.0	0.0	44.6	2674.6	19.3
15	11091.6	15290.0	0.0	37.9	2645.1	14.0
16	10800.5	15290.0	0.0	41.6	2273.4	20.5
17	11201.0	15290.0	0.0	36.5	1451.4	23.5
18	11094.7	15290.0	0.0	37.8	1331.7	25.8
19	10518.7	15290.0	681.0	38.9	903.6	30.3
20	10018.0	15290.0	680.8	45.8	2379.2	22.1
21	9524.6	15290.0	1813.0	41.5	1710.5	23.5
22	9212.9	15290.0	1438.2	50.3	1255.0	36.7
23	8174.4	15290.0	3512.0	44.1	1870.4	21.2
24	7536.1	15290.0	2924.6	64.1	1022.5	50.5
25	8116.6	15290.0	3653.0	43.4	610.8	35.8
26	7503.7	15290.0	2956.2	64.4	1288.6	47.2

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-14

1995 Peak Demand and Reserve Capacity by Biweekly Interval:
Texas Utilities Electric Company

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	14775.0	24324.0	1970.0	51.3	3264.5	29.2
2	16616.4	24324.0	1970.0	34.5	1692.1	24.3
3	14269.2	24324.0	3855.0	43.4	2075.0	28.9
4	12972.6	24324.0	3503.4	60.5	3844.0	30.9
5	13796.9	24324.0	4320.1	45.0	1759.0	32.2
6	11779.9	24324.0	5829.6	57.0	353.9	54.0
7	11458.3	24324.0	5978.5	60.1	2295.1	40.1
8	11403.1	24324.0	6465.8	56.6	1729.9	41.4
9	13060.6	24324.0	3584.1	58.8	2511.6	39.6
10	15786.5	24324.0	2297.8	39.5	3103.2	19.9
11	16267.1	24324.0	1203.9	42.1	4603.0	13.8
12	17101.2	24324.0	0.4	42.2	3351.5	22.6
13	19399.6	24324.0	0.0	25.4	2404.6	13.0
14	19248.7	24324.0	0.0	26.4	3932.3	5.9
15	20099.5	24324.0	0.0	21.0	2978.9	6.2
16	18429.9	24324.0	0.0	32.0	3725.9	11.8
17	20643.0	24324.0	0.0	17.8	3434.2	1.2
18	20854.0	24324.0	0.0	16.6	3140.5	1.6
19	19125.7	24324.0	0.0	27.2	4658.2	2.8
20	17123.6	24324.0	875.0	36.9	2184.6	24.2
21	13898.9	24324.0	4490.0	42.7	1744.9	30.1
22	12446.4	24324.0	3858.7	64.4	830.0	57.8
23	12271.9	24324.0	5994.9	49.4	1330.5	38.5
24	13735.5	24324.0	4366.9	45.3	4047.9	15.8
25	14728.9	24324.0	5435.0	28.2	1750.0	16.4
26	13259.0	24129.0	1026.7	74.2	1547.6	62.6

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

TABLE 4.1-15

1995 Peak Demand and Reserve Capacity by Biweekly Interval:
Central & Southwest Company

Biweekly Interval	Peak Load* (MW)	Installed Capacity* (MW)	Scheduled Outage (MW)	Operating Reserve (%)	Expected Forced Outage (MW)	Expected Reserve (%)
1	4382.6	5989.0	372.0	28.2	658.9	13.1
2	4082.5	5989.0	304.3	39.2	99.2	36.8
3	4006.7	5989.0	993.1	24.7	281.6	17.7
4	3497.9	5989.0	1836.0	18.7	258.4	11.3
5	3560.2	5989.0	1809.7	17.4	576.7	1.2
6	3510.5	5989.0	1612.6	24.7	0.0	24.7
7	3594.2	5989.0	1581.8	22.6	416.0	11.0
8	4102.8	5989.0	1013.9	21.3	464.0	10.0
9	3877.6	5989.0	421.7	43.6	315.0	35.5
10	4673.9	5989.0	108.0	25.8	500.6	15.1
11	4843.7	5989.0	0.0	23.6	809.0	6.9
12	4858.9	5989.0	0.0	23.3	141.9	20.3
13	4828.7	5989.0	0.0	24.0	162.7	20.7
14	4652.1	5989.0	0.0	28.7	406.3	20.0
15	4810.7	5989.0	0.0	24.5	1127.7	1.1
16	5478.4	5989.0	0.0	9.3	1229.2	-13.1
17	5269.8	5989.0	0.0	13.6	157.8	10.7
18	4972.5	5989.0	0.0	20.4	247.0	15.5
19	4975.7	5989.0	0.0	20.4	225.2	15.8
20	4570.2	5989.0	357.0	23.2	97.8	21.1
21	3988.6	5989.0	565.0	36.0	443.6	24.9
22	3685.9	5989.0	779.6	41.3	95.6	38.7
23	3614.7	5989.0	1014.8	37.6	690.8	18.5
24	3497.9	5989.0	1023.9	41.9	329.8	32.5
25	3609.9	5989.0	1261.8	31.0	89.1	28.5
26	3749.8	5989.0	550.4	45.0	556.0	30.2

*Both peak demand and installed capacity have been modified to exclude hydroelectric generation

projecting that its system will become winter peaking. COA has the largest differential between its lowest peak, in interval 6, and highest peak in interval 18. CPSB is another system which shows a large differential between low and high peaks. These large differences indicate that the two utilities have low annual load factors. As shown, the reference case demand forecast predicts only a 47.5 percent annual load factor for City of Austin in the year 1990. The utility with lowest differential between low and high peak is HL&P, which also happens to be the system with the largest annual load factor, 60 percent.

Low annual load factors usually indicate that the major constituents of demand are residential and commercial loads, which are sensitive to seasonal weather variations. High annual load factors usually indicate that a sizable portion of demand is industrial load, which tends to stay relatively constant throughout the entire year. This observation is confirmed by demand forecasts made by both the utilities and the PUCT staff. The official forecast released in 1986 by the PUCT staff shows that over 96 percent of the total sales in the City of Austin in 1990 will be to residential and commercial customers. In contrast, in the same year the sales to residential and commercial customers are projected to comprise only 45 percent of total sales for HL&P.

The "reserves" columns are indicators of system reliability under own-load operations. They are also indicators of excess capacity within the systems. Although a system is expected to have certain capacity set aside for system reserve, high reserves indicate that the system has available resources for exporting power.

For each of the study years, COA has extremely high levels of excess capacity, particularly during winter. During the winter of 1990 the excess capacity of COA is 138 percent of expected load. San Antonio also shows relatively high levels of excess capacity during the winter period. In contrast, LCRA is projected to have negative reserves. These negative numbers indicate potential supply shortages that LCRA is likely to encounter during the year under own-load operation. HL&P and C&SW show comfortable reserve capacities while TUEC shows a tight reserve capacity during the summer period.

The "Operating Reserve" and "Expected Reserve" shown in Tables 4.1-4 through 4.1-15 are not calculated in the same manner as "Reserve Margin" shown in Table 3.2-2. The common definition of "Reserve Margin" used by ERCOT members reflects the reliability of each utility's system under normal operating conditions. In contrast, the MAPS/MWFLOW model applies a slightly different formula to calculate operating reserve and expected reserve for each biweekly interval for each utility's system. These formulas which adjust for planned and random outages are as follows:

$$R = \frac{(C - O_s - P)}{P} 100$$

and

$$R_e = \frac{(C - O_s - O_f - P)}{P} 100$$

where

R = Operating reserve (percent)

R_e = Expected reserve (percent)

C = Installed capacity (MW)

O_s = Scheduled outage (MW)

O_f = Expected forced outage (MW)

P = Peak load (MW)

4.1.10 Transmission line monitoring

The significance of monitoring transmission lines is discussed in Appendix A. Because of the limitations of the MAPS/MWFLOW model and computer resources, it is not possible to monitor all of the nearly 3,000 transmission lines in the ERCOT network. MAPS/MWFLOW allows fewer than 300 lines to be monitored.

Since transmission limitation is one of the major issues regarding the amount of power that can be shipped over the network, substantial effort was expended in the analyses of line monitoring during the development of the earlier base cases. In one analysis, lines that appeared to carry heavy load as indicated in the ERCOT loadflow results were added to the list of monitored lines. From these analyses, the earlier set of 96 lines was obtained and used in the model.

However, at the December review meetings, ERCOT utility representatives strongly expressed their doubts about the number and selection of the monitored lines; and two of them (COA and LCRA) subsequently worked together with the study staff to run a set of 2,158 loadlow cases for the 1990 base case. The results of this process indicated that for approximately 18% of the cases, even under the assumption of no contingencies, one or more transmission lines were loaded beyond their limits. This provided a clear indication that the original set of 96 monitored lines had to be enlarged.

Monitored lines are those for which the MAPS/MWFLOW model include constraints in order to assure that they are not overloaded. In the reference cases for 1986, 1990 and 1995, this constraint set has been enlarged to contain between 250 and 290 lines. The new set of monitored lines includes: (1) the original 96 lines identified by the study staff, (2) all of the lines identified in the LCRA/COA loadflow analysis, (3) all the lines that appear in ERCOT's 1986 and 1987 transfer limit study, and (4) other components of the network identified by the staff from the original ERCOT loadflows that might overload if constraints were not enforced. A complete list of monitored lines for 1990 is shown in Tables 4.2-15 and 4.2-16, along with the calculated line loadings and limits which will be discussed in Section 4.2.5 on Transmission Limitations.

According to the developer of the model, if selected critical lines are monitored and do not exceed their limit, it is unlikely that other less critical lines will be overloaded. However, because of the size of the ERCOT network, it cannot be guaranteed that no critical elements have been overlooked. Identifying critical elements in the network under a given state of generation and load is a major study in itself. As more information about critical elements becomes available, further tests should be made to measure the sensitivities and impacts of these critical elements on the overall results.

4.1.11 Calculation of Savings Allocation

The method of savings allocation used in the discussion is just one of several possible methods. This method, as discussed in Appendix A, uses a 50/50 split of the savings between sellers and buyers. It is used only to demonstrate that it is possible for every pool member to benefit from the pool operation; hence the discussion about the savings individual utilities receive should not be interpreted as a policy recommendation of this study.

The savings allocation can take into account the use of transmission lines that belong to other members. However, regardless of the method of savings allocation used, the overall savings remain unchanged. The main fact is that if the savings are allocated more to one company, the remaining share for others will be reduced; but the overall savings resulting from the transactions do not change.

4.2 Reference Case Results

Wherever possible, the reference case results for each of the relevant topics are discussed simultaneously for the years 1986, 1990 and 1995. Comparisons are made to show the similarity and/or contrast in overall savings and system operations. Input data and output files for the reference cases appear in Appendices B and C. For the years 1990 and 1995 the utilities' demand forecast is designated as the reference case to be consistent with the capacity projections provided by the utilities for that year.

The discussion of results in this chapter and the next chapter often involves comparisons between "own-load" and "pool" operations. The own-load operation reflects an assumption that the utilities do not engage in exchanging power for economic purposes. The pool operation represents an assumption that the utilities will closely coordinate operations in order to globally minimize production costs. The two assumptions represent opposite extremes and thus produce boundary conditions. While the current ERCOT system operation represents neither of the two extremes, in the past it has been very similar to the own-load operation. However, the expected additional use of the ERCOT brokerage system will likely move the operation closer to the other boundary. The comparison between these two extremes represents the upper bound of the potential transactions and savings, which can also be used as a comparison of the success of the ERCOT brokerage system.

4.2.1 Overall Savings

Tables 4.2-1 through 4.2-4 summarize the annual savings between pool and own-load operation for the years 1990 and 1995. During these two years, the model reports the total variable costs for own-load operation (assuming diverging fuel prices) to be \$4,398.0 billion and \$7,547.0 billion, respectively; or (assuming converging fuel prices)

TABLE 4.2-1

Summary of Annual Generation and Total Savings in 1990:
Reference Case - Diverging Gas Prices

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,024	8,444	452	1,872	1,420	127.7	160.7	9.1	118.6
LCRA	7,858	10,872	246	3,259	3,013	170.9	238.8	15.5	155.4
CPSB	13,227	11,156	2,387	316	-2,071	279.4	207.0	14.0	265.4
HL&P	56,165	76,957	58	20,850	20,792	1,256.4	1,716.0	94.9	1,161.5
TUEC	94,338	71,552	23,140	354	-22,786	2,013.6	1,279.9	107.7	1,905.9
C&SW	24,052	23,684	1,723	1,355	-368	540.0	548.4	6.0	544.0
Total	202,664	202,664	28,005	28,005		4,398.0	4,150.8	247.2	4,150.8

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 4.2-2

Summary of Annual Generation and Total Savings in 1990:
Reference Case - Converging Gas Prices

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,024	7,016	775	767	-8	126.1	120.8	3.8	122.2
LCRA	7,858	9,812	324	2,278	1,954	174.2	219.2	5.0	169.2
CPSB	13,227	16,706	144	3,623	3,479	251.5	331.6	6.6	244.9
HL&P	56,165	60,825	671	5,330	4,659	1,331.9	1,429.0	13.2	1,318.7
TUEC	94,338	83,995	10,907	564	-10,343	1,737.9	1,456.9	22.3	1,715.6
C&SW	24,052	24,311	1,536	1,795	259	527.8	536.1	4.8	523.0
Total	202,664	202,664	14,357	14,357		4,149.4	4,093.6	55.8	4,093.6

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 4.2-3

Summary of Annual Generation and Total Savings in 1995: Reference Case - Diverging Gas Prices

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	9,210	9,595	799	1,184	385	253.9	265.0	12.3	241.6
LCRA	10,209	12,116	426	2,333	1,907	320.2	384.7	20.0	300.1
CPSB	16,953	18,629	586	2,262	1,676	481.8	524.2	23.0	458.7
HL&P	61,780	77,195	685	16,099	15,414	1,868.5	2,421.3	119.7	1,748.9
TUEC	114,333	96,502	19,359	1,528	-17,831	3,631.5	2,663.2	156.6	3,474.9
C&SW	28,705	27,153	2,885	1,334	-1,551	991.1	933.9	23.1	968.1
Total	241,190	241,190	24,741	24,741		7,547.0	7,192.3	354.7	7,192.3

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 4.2-4

**Summary of Annual Generation and Total Savings in 1995:
Reference Case - Converging Gas Prices**

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	9,210	8,681	1,141	612	-529	241.2	214.5	6.6	234.6
LCRA	10,209	10,809	753	1,352	599	319.7	334.6	8.7	311.0
CPSB	16,953	23,082	129	6,258	6,129	452.6	661.8	20.1	432.5
HL&P	61,780	64,166	2,196	4,583	2,387	1,932.9	2,010.3	21.2	1,911.7
TUEC	114,333	107,529	8,877	2,073	-6,804	3,122.1	2,802.7	38.0	3,084.0
C&SW	28,705	26,923	2,907	1,125	-1,782	922.3	858.7	13.4	908.9
Total	241,190	241,190	16,003	16,003		6,990.8	6,882.8	108.1	6,882.8

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

to be $4,149.4 billion and $6,990.8 billion. Comparable costs for pool operation (assuming diverging fuel prices) are $4,150.8 billion and $7,192.3 billion, respectively; or (assuming converging fuel prices) $4,093.6 and $6,882.8 billion. The cost increase from 1990 to 1995 is due mainly to the increase in fuel price projections.

The amounts of energy exchanged among the utilities for these two years (assuming diverging fuel prices) are 28.0 billion and 24.7 billion KWH which translate respectively to 13.8 and 10.3 percent of total ERCOT generation; or (assuming converging fuel prices) 14.4 billion and 16.0 billion KWH which translate respectively to 7.1 and 6.6 percent of total ERCOT generation.

Although the total costs and the level of transactions (assuming diverging fuel prices) are roughly comparable to earlier base case results, the savings levels are reduced to $247.2 million in 1990 and to $354.7 million in 1995. These savings translate into 5.6 and 4.7 percent, respectively, of total variable operating costs under own-load operation. The reference case results (assuming converging fuel prices) are, as expected, substantially lower with 1990 savings equal to $55.8 million or 1.3% and 1995 savings equal to $108.1 million or 1.6%.

The large differential between the converging and diverging fuel price scenarios is further supported by analysis of the 1986 reference cases. Although the version of MAPS/MWFLOW used in the study is not currently configured to handle multiple fuels for each generating unit -- a more accurate reflection of the actual historical conditions -- upper and lower limits can be established by using actual average gas prices to represent the diverging conditions and the actual incremental fuel prices to represent the converging conditions. As shown in Tables 4.2-15 and 4.2-16, the average gas price case indicates an upper limit on transactions of 30.7 billion KWH (16.8% of total system energy) and calculated annual savings of $239.6 million (6.4% of costs). Clearly, the provisions of then-existing contracts with take-or-pay obligations coupled with the existence of low priced gas in the short-term spot market indicate that such levels would have been unattainable. For example, the model shows TUEC to be a net purchaser of 24.0 billion KWH; however, calculations made by TUEC and supplied to the study staff indicate that the maximum amount of energy which could have been "backed down" from its gas-fired units is 5.9 billion KWH.

In order to address such discrepancies, the alternative reference case uses each utility's reported incremental natural gas prices in the analysis. This assumption results in a potential transactions level of only 14.7 billion KWH (8.0% of system energy) and reduces the potential savings level to only $51.2 million (1.7% of total cost). Although this result is biased downward as a result of assuming that each utility can acquire all of its gas requirements at its incremental cost, it is the best estimate of the actual potential, given the gas market conditions and the limitations of the model. It is also consistent with and lends support to the magnitude of the range shown between the forecast reference cases using diverging (i.e. average) and converging (i.e. incremental) gas prices. Finally, for example, the TUEC net purchase of 1.9 billion KWH is well within the backdown limit of 5.9 billion KWH described above while HL&P, as expected, is shown to be the largest exporter with potential sales of 8.8 billion KWH. As a basis of comparison, actual ERCOT transactions in 1986 were only 2.3 billion KWH, approximately 15% of the estimated potential. In 1987, these ERCOT transactions increased to 3.5 billion KWH.

It should be noted that the incremental increase in line losses is not taken into consideration in the savings calculation. However, the results from staff analysis of selected loadflow cases indicate that the increase in line losses as a result of increased levels of bulk power transactions will not significantly reduce the overall savings.

Although the version of MAPS/MWFLOW used in the study cannot calculate incremental line losses, it can generate a data file for loadflow analysis. When a loadflow analysis is made for the summer peak hour in 1990 using the MAPS/MWFLOW data file that represents coordinated operation, the results show that transmission line losses are increased by only 25 percent from the ERCOT summer peak loadflow. In addition, the results from the loadflow analysis indicate that the total line losses at the transmission level (69 KV and above) is only about 1.6 percent of generation requirements. This indicates that the majority of line losses occur at the distribution level which is not affected by changes in the operation of the bulk power system.

The breakdown of energy import/export during the study years is shown in Figures 4.2-1 and 4.2-2. During the two study years, TUEC is consistently the largest net importer, while HL&P is consistently the largest net exporter. As discussed earlier, for a transaction to occur, there must be available capacity, price differentials, and available transmission. In these study cases, HL&P has both high excess capacity available for export and low cost supplies from cogeneration and low gas prices. On the other hand, the demand/supply projections for TUEC used in this study indicate a need to purchase power since it has both tight supply and higher natural gas prices.

During the study years (assuming diverging gas prices), TUEC's net imports are 22,786 million and 17,831 million KWH while HL&P's net exports are 20,792 million and 15,414 million KWH, respectively; or (assuming converging gas prices), TUEC's net imports are 10,343 million and 6,804 million KWH while HL&P's net exports are 4,659 million and 2,387 million KWH, respectively. Although the TUEC service area is expected to experience an economic slowdown, the degree is expected to be less severe than that in Houston. Given the current demand and supply projections, TUEC will have a much tighter supply than HL&P.

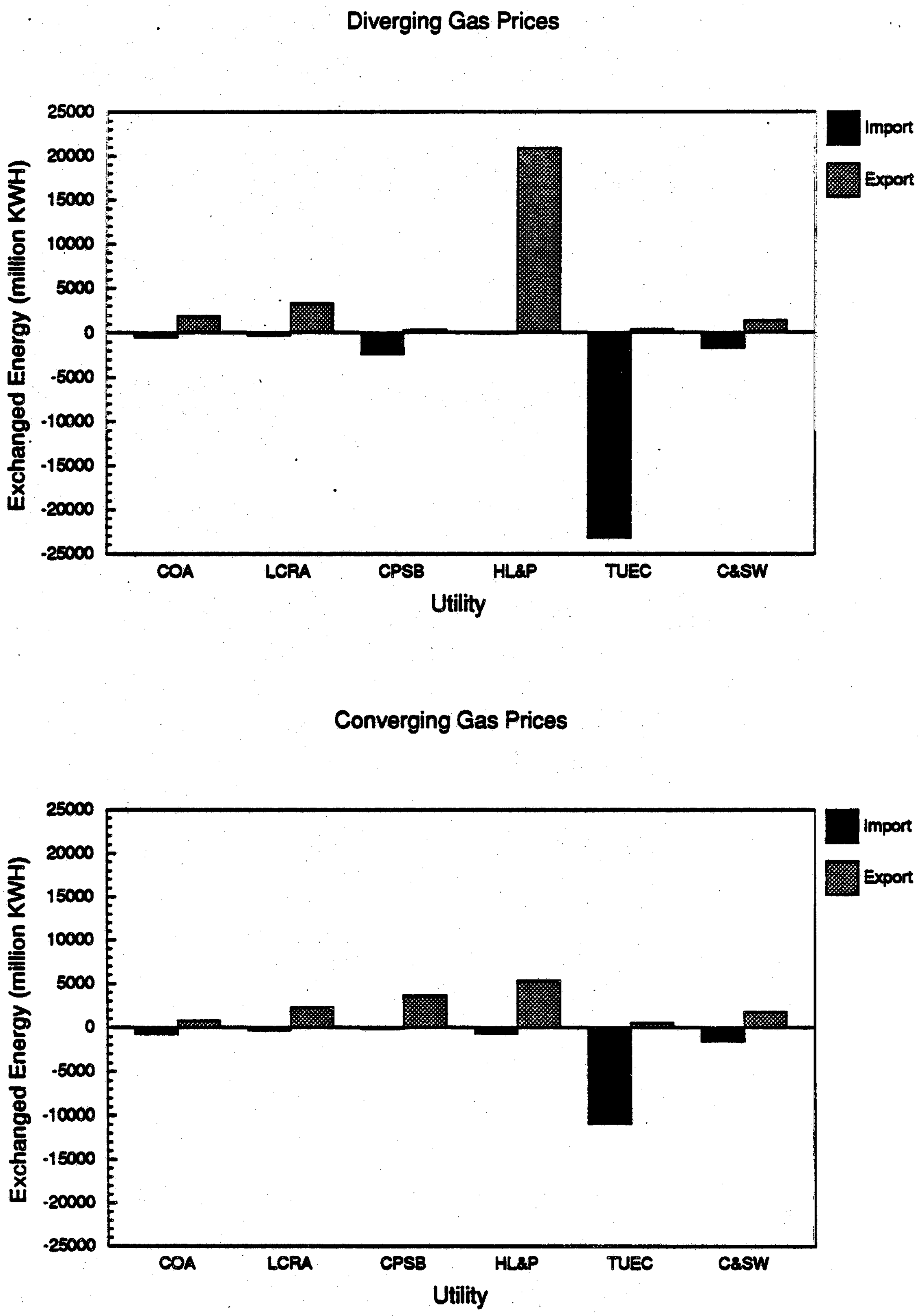
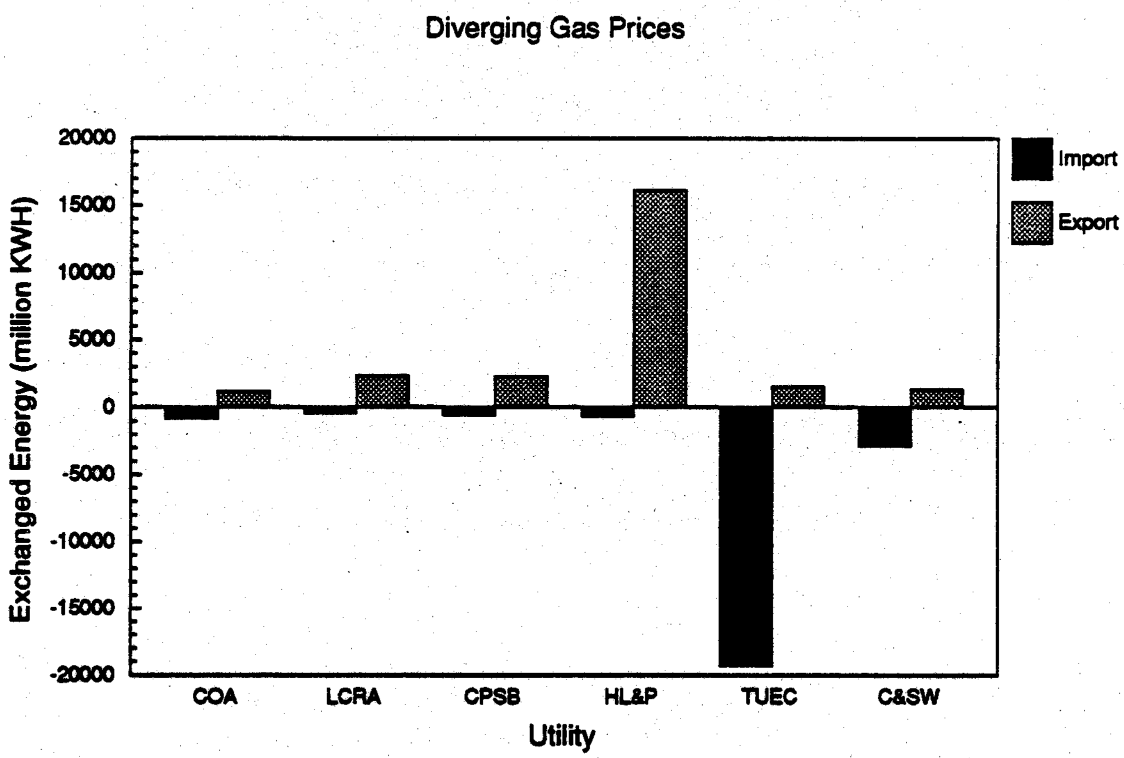


Figure 4.2-1 Energy Import and Export in 1990



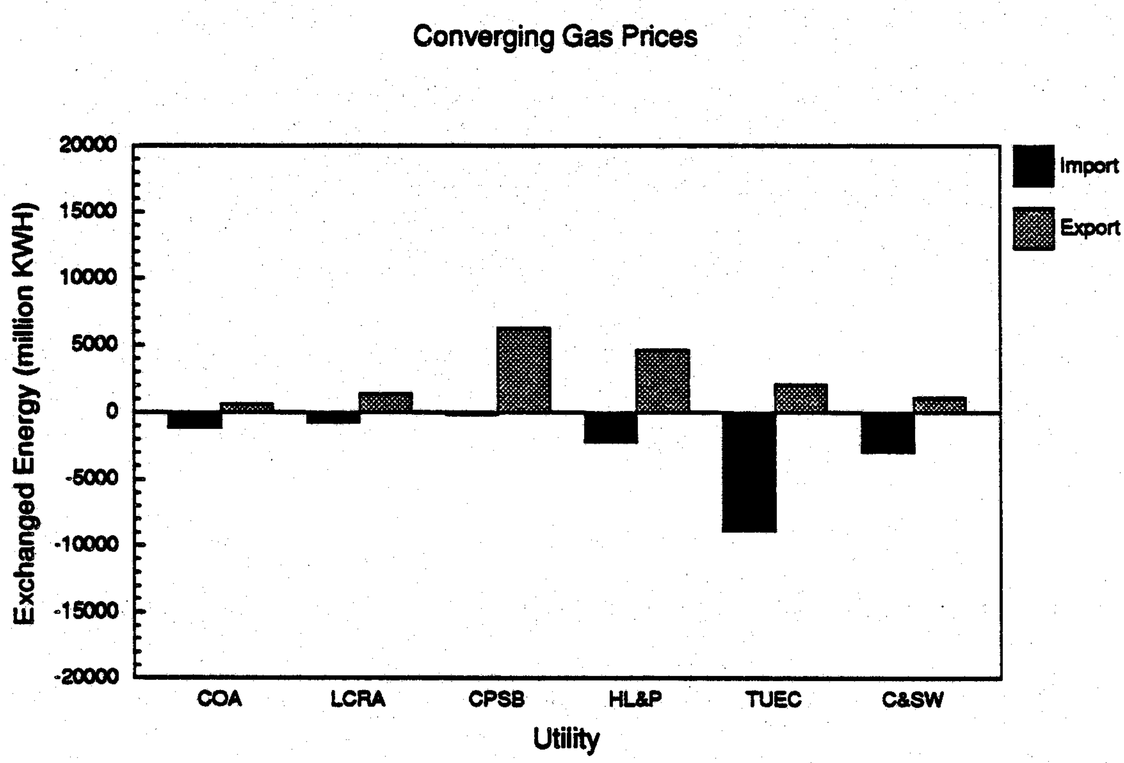


Figure 4.2-2 Energy Import and Export in 1995

Like HL&P, LCRA also exports more energy than it imports due to its low average gas price. In 1990 and 1995 (assuming diverging gas prices), its net exports are 3,013 and 1,907 million KWH, respectively; or (assuming converging gas prices), its net exports are 1,954 and 599 million KWH. The decrease in energy export is related to the lower projected reserve margin for 1995. LCRA's relatively small energy purchases, while exceeded by its sales, reflects its increasing winter capacity and energy needs.

With the assumption of diverging gas prices, another net exporter in the system is COA. The amount of net energy export from COA is 1,420 million KWH in 1990 and 385 million KWH in 1995. However, with converging gas prices, COA imports 8 million KWH in 1990 and 529 million KWH in 1995.

Although it has moderately high reserve capacity, CPSB's transaction position is quite sensitive to gas price assumptions. Assuming diverging fuel prices, the results show that CPSB imports 2,071 million KWH in 1990, then exports 1,676 million KWH in 1995. As indicated by the 1990 results, a utility with available capacity to export, can itself be a net importer if its available supply is not economical enough to compete in the bulk power market. However, assuming converging fuel prices, the results show that CPSB exports 3,479 million KWH in 1990, then becomes the largest exporter with 6,129 million KWH in 1995. This shift indicates that with similar gas prices, there is a high potential for competition among utilities that have exporting capability, and utilities that can supply at lower costs will tend to export more into the pool.

The import/export trend in C&SW also shows some mixed results. With diverging fuel prices, C&SW is a net importer in both of the study years, but the amounts are very small in relationship to its total energy. With converging fuel prices, however, C&SW is a small net exporter in 1990, but becomes a small net importer in 1995. While the situation earlier described for CPSB demonstrates the impact of fuel prices, the situation for

C&SW demonstrates the impact of reserve capacity. While their fuel prices, particularly natural gas, are competitive during the two study years, the average expected reserve margin drops from 28.5% in 1990 to only 18 percent in 1995. The tight reserve in 1995 removes the ability to export energy from C&SW and causes it to become a net importer.

Although some utilities are net exporters while others are net importers, all utilities engage in both types of transactions. This means that under pool operation, utilities can take advantage of seasonal fluctuations in supply and demand to move power, resulting in lower overall operating costs.

If the method of split savings discussed in Appendix A were used, TUEC would receive the largest benefit from engaging in the bulk power market with savings of $108 million and $157 million (assuming diverging gas prices), but only $22.3 million and $38.0 million (assuming converging gas prices) during the study years. The second largest beneficiary would be HL&P with savings of $95 million and $120 million (assuming diverging gas prices), but only $13.2 million and $21.2 million (assuming converging gas prices) during the study years. While TUEC benefits mainly from buying, HL&P benefits mainly from selling. It is reasonable to expect that HL&P and TUEC would be the two largest beneficiaries from engaging in bulk power transactions, since they are also the two largest utilities in the state.

It should be noted that the cost allocation method is merely an example which illustrates that all of the involved parties can benefit from exchanging power. Because the model used in the study is designed to optimize operating costs globally without paying attention to the transaction mechanism, it does not keep track of explicit transactions. This makes it impossible to calculate wheeling costs if they are charged (in some power pools, they are not). For example, when it reports that LCRA buys 246 million and sells 3,259 million KWH in 1990, the model as currently configured cannot tell to whom

LCRA sells and from whom it buys. When the emphasis is on overall savings, lack of this information is not especially critical; but does point out the need for further analysis and research using a model which permits identification of specific transactions.

Compared to the ERCOT brokerage system, these savings are equivalent to the savings before wheeling payments to the affected systems. Therefore, when wheeling charges are assessed, the savings split will change. If, for example, it is assumed that buyers are reponsible for wheeling charge payments, TUEC's savings will be less than reported by the model while savings of companies affected by TUEC's transactions, such as LCRA's, will be higher. This means that wheeling charges only affect the savings allocation, not the overall savings. The model is designed to dispatch the system to yield global optimization of operating costs without paying any attention to the transaction mechanisms or arrangements. While there may be infinite varieties of transaction arrangements which affect wheeling calculations, there can be only one optimum solution for a given problem formulation and set of constraints.

Whether the level of energy exchanged during the study years declines slightly in 1995 (assuming diverging gas prices), or increases slightly in 1995 (assuming converging gas prices), the amount of savings increases markedly in 1995. This provides one clear indication that the amount of savings is very sensitive to the fuel price assumptions. Another clear indication of this sensitivity is demonstrated by the much greater relative change in the level of savings than in the level of transactions in a given study year when the assumption is changed from diverging to converging gas prices. For example, in 1990, this change in assumptions causes transactions to fall by 48.7% but savings are reduced by 77.4%. Further tests of alternative fuel price assumptions are made and reported in the next chapter.

4.2.2 Generation Patterns

Tables 4.2-5 through 4.2-8 show the comparison of generation patterns of the modeled utilities between own-load and pool operations during the study years for the reference cases. The generation is shown broken down by fuel type. The "other" category includes cogeneration and minor sources. Cogeneration is assumed to be bound by the contracts between utilities and cogenerators and does not change between own-load and pool operations. Minor sources include external purchases to make up for the generation requirements in case of shortages. Available hydro generating units are treated as pondage units (see Appendix A) with energy production determined by downstream water requirements. Hydro generation, therefore, does not appear in the tables. The impacts of varying supply from cogeneration are tested in the next chapter. COA has a refuse unit that increases its output slightly under the coordinated operation.

During the study years for all of the reference cases, TUEC reduces the use of its gas units considerably under the coordinated operation. This reduction is replaced by more economical generation from other utilities. The major source of replacement is gas generation from HL&P, although in 1995 with converging fuel prices CPSB is projected to contribute somewhat more gas-fired energy than HL&P does. Other sources include coal, lignite and nuclear generation from other utilities. Figures 4.2-3 and 4.2-4 show changes in generation by fuel type during the study years. These figures also show a slight reduction of gas generation by CPSB in 1990, and C&SW in 1995 (assuming diverging gas prices), as well as an increase in coal and lignite use by HL&P in 1990. The relatively small changes in the use of the other fuel types indicate that the base load units are being utilized efficiently under the different operating arrangements, and that little inter-fuel substitution takes place.

TABLE 4.2-5

Electricity Generation by Fuel Type in 1990:
Reference Case - Diverging Gas Prices
(million KWH)

	Gas	Coal	Lignite	Oil	Nuclear	Others	Total
<u>Own-Load Operation</u>							
COA	1,275	3,355	0	0	2,257	137	7,024
LCRA	2,267	5,574	0	0	0	17	7,858
CPSB	3,716	5,415	0	0	3,880	216	13,227
HL&P	25,418	7,747	8,408	0	4,324	10,269	56,165
TUEC	39,387	0	36,527	0	11,538	6,886	94,338
C&SW	12,130	8,321	0	0	3,600	1	24,052
Total	84,193	30,412	44,935	0	25,598	17,526	202,664
<u>Pool Operation</u>							
COA	2,248	3,773	0	0	2,286	138	8,444
LCRA	4,525	6,347	0	0	0	0	10,872
CPSB	1,373	5,560	0	0	4,001	223	11,156
HL&P	41,568	11,883	8,806	0	4,401	10,299	76,957
TUEC	16,137	0	36,990	0	11,539	6,886	71,552
C&SW	12,206	7,877	0	0	3,600	0	23,684
Total	78,057	35,440	45,796	0	25,826	17,546	202,664

TABLE 4.2-6

Electricity Generation by Fuel Type in 1990:
Reference Case - Converging Gas Prices
(million KWH)

	Gas	Coal	Lignite	Oil	Nuclear	Others	Total
Own-Load Operation							
COA	1,323	3,308	0	0	2,257	137	7,024
LCRA	2,024	5,817	0	0	0	17	7,858
CPSB	4,050	5,081	0	0	3,880	216	13,227
HL&P	22,947	10,218	8,408	0	4,324	10,269	56,165
TUEC	39,386	0	36,528	0	11,538	6,886	94,338
C&SW	12,194	8,257	0	0	3,600	1	24,052
Total	81,922	32,681	44,937	0	25,598	17,526	202,66
Pool Operation							
COA	751	3,841	0	0	2,286	138	7,016
LCRA	3,360	6,451	0	0	0	0	9,812
CPSB	6,685	5,799	0	0	4,000	223	16,706
HL&P	26,179	11,172	8,774	0	4,400	10,299	60,825
TUEC	28,640	0	36,931	0	11,537	6,886	83,995
C&SW	12,643	8,068	0	0	3,600	0	24,311
Total	78,260	35,331	45,705	0	25,823	17,546	202,664

TABLE 4.2-7

Electricity Generation by Fuel Type in 1995:
Reference Case - Diverging Gas Prices
(million KWH)

	Gas	Coal	Lignite	Oil	Nuclear	Others	Total
<u>Own-Load Operation</u>							
COA	3,032	3,756	0	0	2,284	139	9,210
LCRA	2,275	7,825	0	0	0	109	10,209
CPSB	2,586	10,180	0	0	3,949	239	16,953
HL&P	24,647	12,604	16,592	0	4,401	3,536	61,780
TUEC	34,817	3,407	49,437	0	11,450	15,222	114,333
C&SW	15,457	9,625	0	1	3,601	21	28,705
Total	82,813	47,398	66,029	1	25,685	19,264	241,190
<u>Pool Operation</u>							
COA	3,313	3,855	0	0	2,286	138	9,593
LCRA	4,146	7,968	0	0	0	0	12,114
CPSB	2,500	11,884	0	0	4,001	242	18,626
HL&P	38,917	13,879	16,462	0	4,401	3,535	77,195
TUEC	16,434	2,128	51,183	0	11,529	15,225	96,499
C&SW	14,357	9,180	0	0	3,601	0	27,138
Total	79,668	48,894	67,645	0	25,817	19,140	241,165

TABLE 4.2-8

Electricity Generation by Fuel Type in 1995:
Reference Case - Converging Gas Prices
(million KWH)

	Gas	Coal	Lignite	Oil	Nuclear	Others	Total
Own-Load Operation							
COA	3,032	3,756	0	0	2,284	139	9,210
LCRA	2,275	7,825	0	0	0	109	10,209
CPSB	2,586	10,180	0	0	3,949	239	16,953
HL&P	24,040	13,211	16,592	0	4,401	3,536	61,780
TUEC	36,858	1,204	49,577	0	11,471	15,224	114,333
C&SW	15,456	9,627	0	1	3,601	21	28,705
Total	84,246	45,803	66,169	1	25,705	19,266	241,190
Pool Operation							
COA	2,415	3,842	0	0	2,286	138	8,681
LCRA	2,862	7,947	0	0	0	0	10,809
CPSB	6,942	11,897	0	0	4,001	242	23,082
HL&P	26,093	13,696	16,441	0	4,401	3,535	64,166
TUEC	29,042	512	51,220	0	11,529	15,225	107,529
C&SW	14,176	9,146	0	0	3,601	0	26,923
Total	81,531	47,039	67,662	0	25,818	19,140	241,190

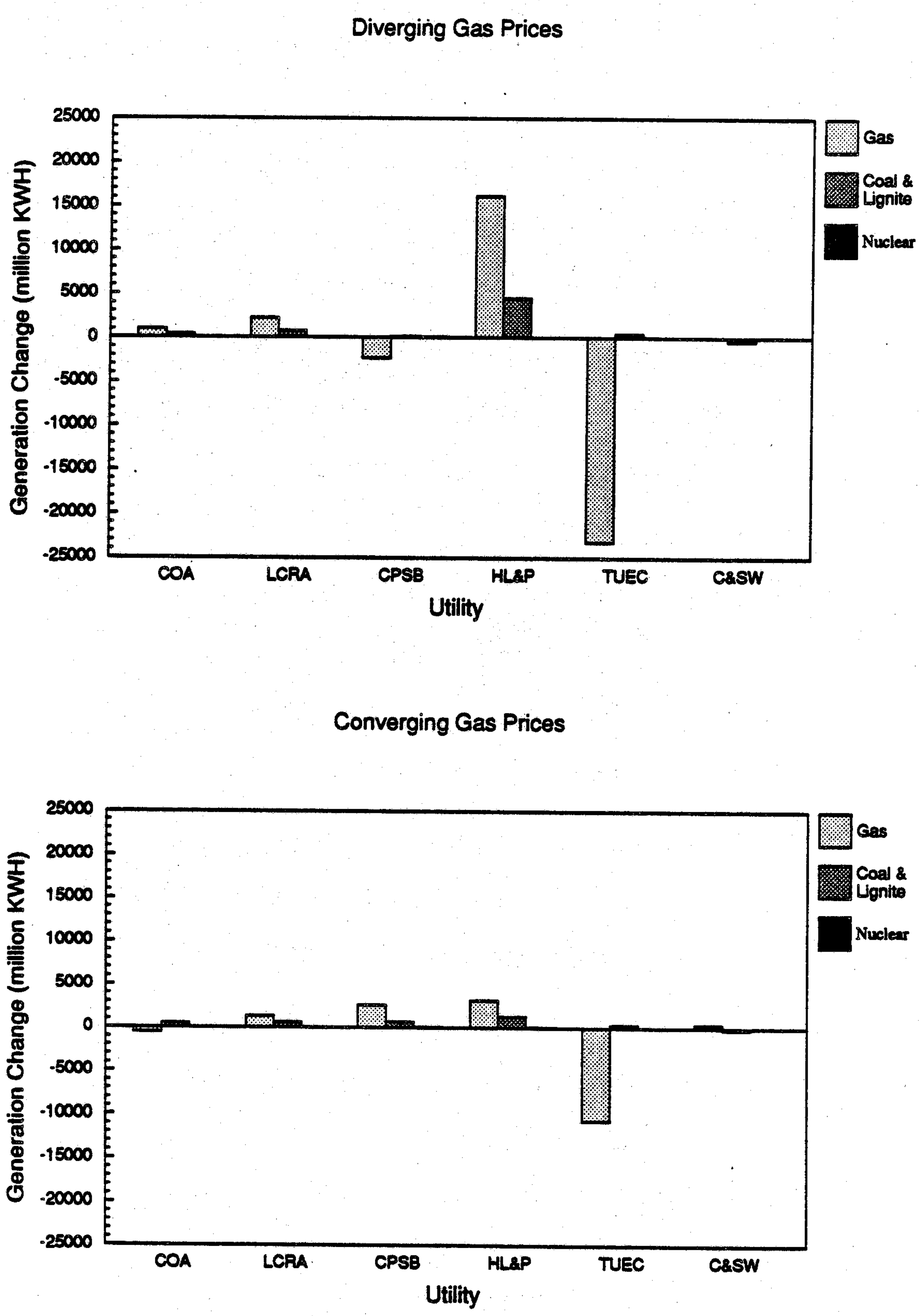
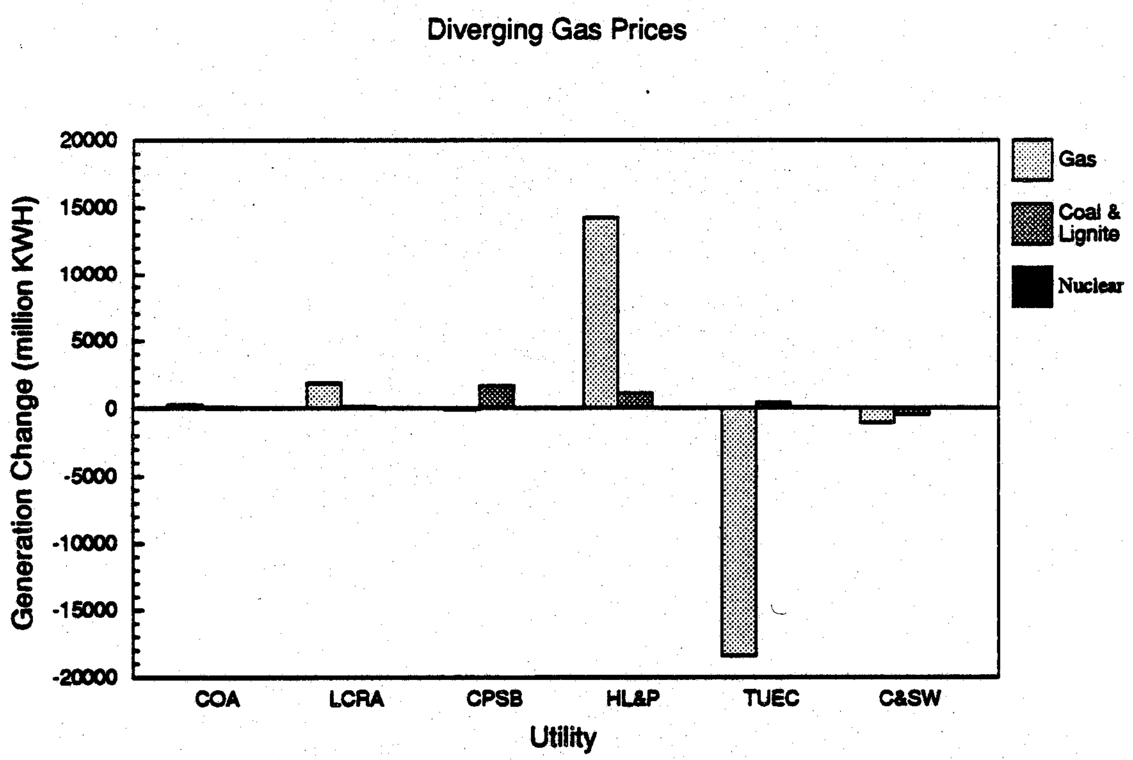


Figure 4.2-3 Change in Generation Pattern in 1990



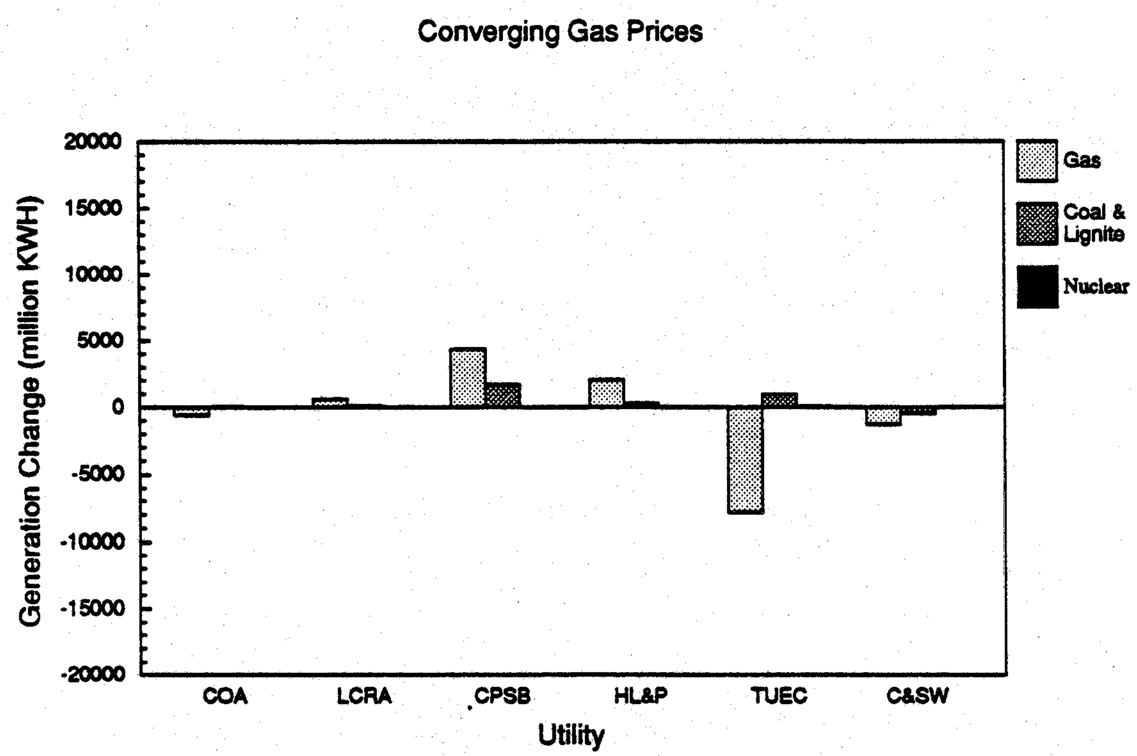


Figure 4.2-4 Change in Generation Pattern in 1995

The generation patterns (assuming diverging gas prices) show that the overall savings from bulk power transactions come from the substitution of expensive fuel by cheaper fuel. With converging fuel prices, the transactions and savings are driven by the greater relative efficiency of available capacity resources. Under either assumption, almost all of the displaced power is gas generation from TUEC. Gas generation from other utilities, particularly HL&P, makes up a large portion of the substituting fuel. For example, in 1990 (assuming converging fuel prices), TUEC decreases its gas generation by 10,746 million KWH. Other utilities altogether increase their gas generation by 7,084 million KWH. Nuclear generation is increased by 225 million KWH, and coal and lignite generation is increased by 3,418 million KWH including 403 from TUEC itself. If diverging gas prices are assumed, the effect is made more pronounced by the price differential.

In the diverging price reference case, TUEC's average gas price is projected to be the highest while HL&P's gas price is projected to be the lowest among the utilities in the study. As demonstrated by the variation in the reference cases when converging prices are used, the values of the savings are very sensitive to fuel price differentials, especially natural gas prices, among different companies. The savings decrease markedly when the differences in gas prices among utilities are eliminated, however, the level of transactions does not decrease in the same proportion as savings because there are other factors that affect the transactions. With diverging fuel prices, however, once the fuel price differential reaches a threshold level, increasing the gap only increases the savings but not the transaction level.

4.2.3 Monthly Interchange

Monthly transactions among the utilities depend on the relationship between demand and supply during each month. Relevant factors include the seasonal characteristics of demand and the maintenance scheduling of power plants. In the reference cases, no coordination in maintenance scheduling is assumed and each utility optimizes its maintenance scheduling based on its own demand. The smaller the utility the more apparent the impact of maintenance scheduling becomes.

Tables 4.2-9 and 4.2-10 show the total monthly generation for each utility during 1990. Figures 4.2-5 through 4.2-10 show the monthly exchange patterns derived from the tables. TUEC is the only utility that is a net importer during all twelve months, irrespective of the gas price assumptions. As expected, imports peak during the summer months but remain relatively high through winter and spring months.

HL&P, the major exporter in the system, also experiences its activity peak during summer months, but also has high net exports during the spring. The total export for April is almost as high that in August. Exports during the other months range between 45 and 72 percent of those in the peak month with diverging gas prices, but show more variability with converging gas prices as January and October HL&P a small net import.

Another utility that is a net exporter (assuming diverging gas prices) for almost the entire year is COA. However, the seasonal pattern differs considerably from that of HL&P. Net exports for COA peak in the winter months of December and January but return to lower levels for the rest of the year, except in October and November when COA becomes a small net importer -- apparently the result of scheduled outage of economical units for maintenance. With the assumption of converging gas prices, COA has positive net exports in the winter months of December, January, and February and a very small

TABLE 4.2-9

Electricity Generation By Month in 1990:
Reference Case - Diverging Gas Prices
(million KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Own-Load Operation												
COA	522	401	432	465	588	718	837	849	686	573	481	472
LCRA	717	539	547	520	607	755	870	834	713	595	575	586
CPSB	914	762	873	952	1175	1370	1538	1519	1272	1079	892	880
HL&P	4562	3782	4144	4213	4890	5307	5664	5640	5027	4786	4125	4025
TUEC	8163	6334	6780	6366	7695	9087	10259	10073	8582	7149	6838	7012
C&SW	1906	1633	1733	1865	2126	2347	2405	2712	2202	1794	1675	1654
Pool Operation												
COA	829	598	574	490	721	845	876	1015	779	571	425	721
LCRA	1166	955	844	810	814	952	1089	1211	982	579	593	698
CPSB	876	623	679	698	986	1043	1134	1302	1111	844	1018	843
HL&P	5941	5194	6032	6486	6689	7029	8124	8001	6709	5899	5617	5235
TUEC	5925	4643	4755	4023	5892	7310	7733	7450	6704	6223	5535	5358
C&SW	2048	1438	1624	1875	1980	2404	2617	2648	2198	1680	1398	1775

TABLE 4.2-10

Electricity Generation By Month in 1990:
Reference Case - Converging Gas Prices
(million KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Own-Load Operation												
COA	522	401	432	465	588	718	837	849	686	573	481	472
LCRA	717	539	547	520	607	755	870	834	713	595	575	586
CPSB	914	762	873	952	1175	1370	1538	1519	1272	1079	892	880
HL&P	4562	3782	4144	4213	4890	5307	5664	5640	5027	4786	4125	4025
TUEC	8163	6334	6780	6366	7695	9087	10259	10073	8582	7149	6838	7012
C&SW	1906	1633	1733	1865	2126	2347	2405	2712	2202	1794	1675	1654
Pool Operation												
COA	1016	473	406	403	584	707	754	840	697	567	387	625
LCRA	1278	906	833	758	682	834	1010	1089	865	688	503	626
CPSB	4545	925	1296	1102	1459	1635	1666	1837	1550	1276	1536	1145
HL&P	ERR	3995	4234	5073	5358	5615	6527	6594	5451	4771	4351	4312
TUEC	7414	5777	6180	5049	6954	8178	8821	8527	7622	7034	6317	6121
C&SW	1958	1375	1560	1996	2044	2614	2795	2740	2298	1639	1492	1800

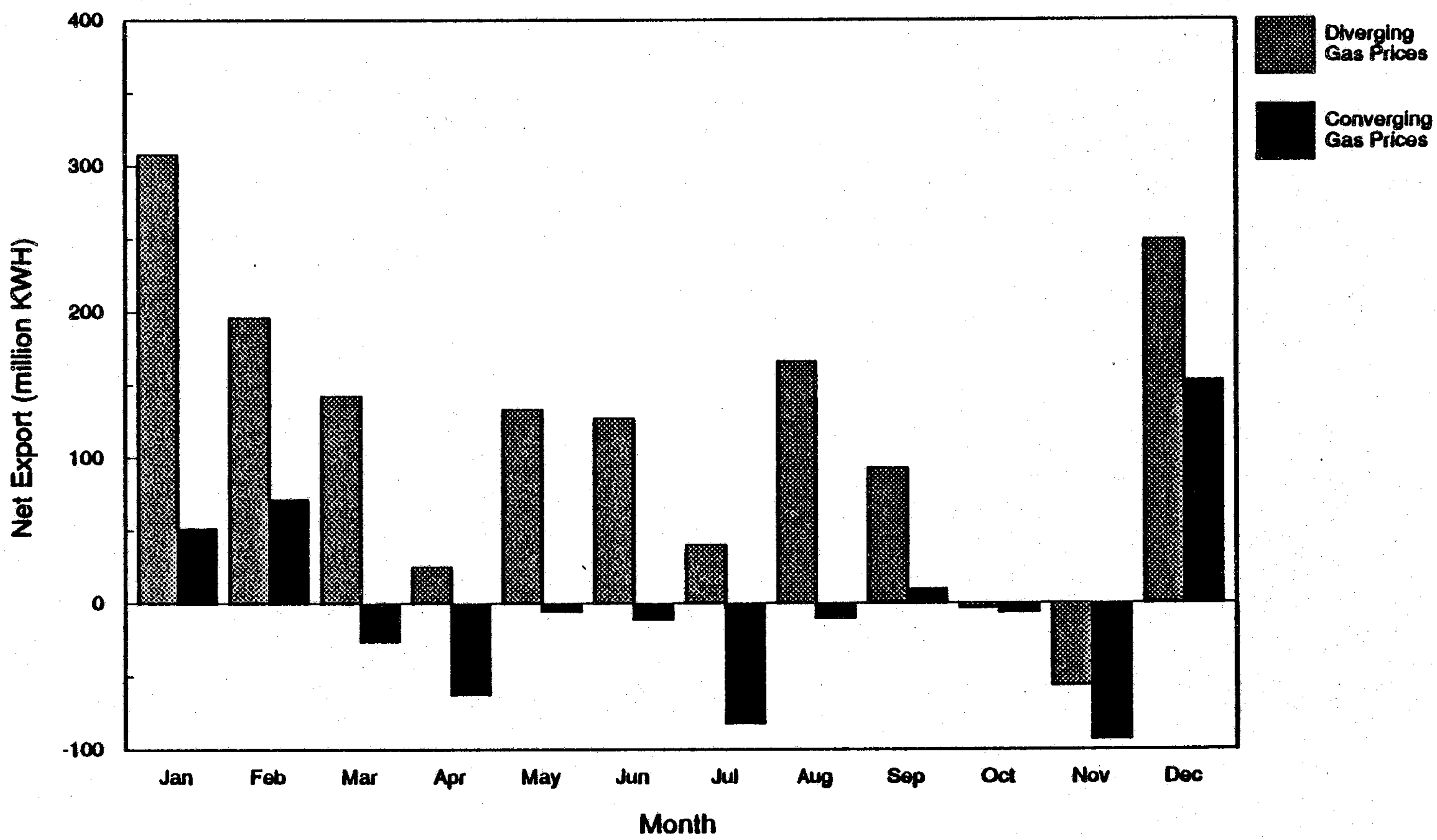


Figure 4.2-5 1990 Net Monthly Interchange :
City of Austin

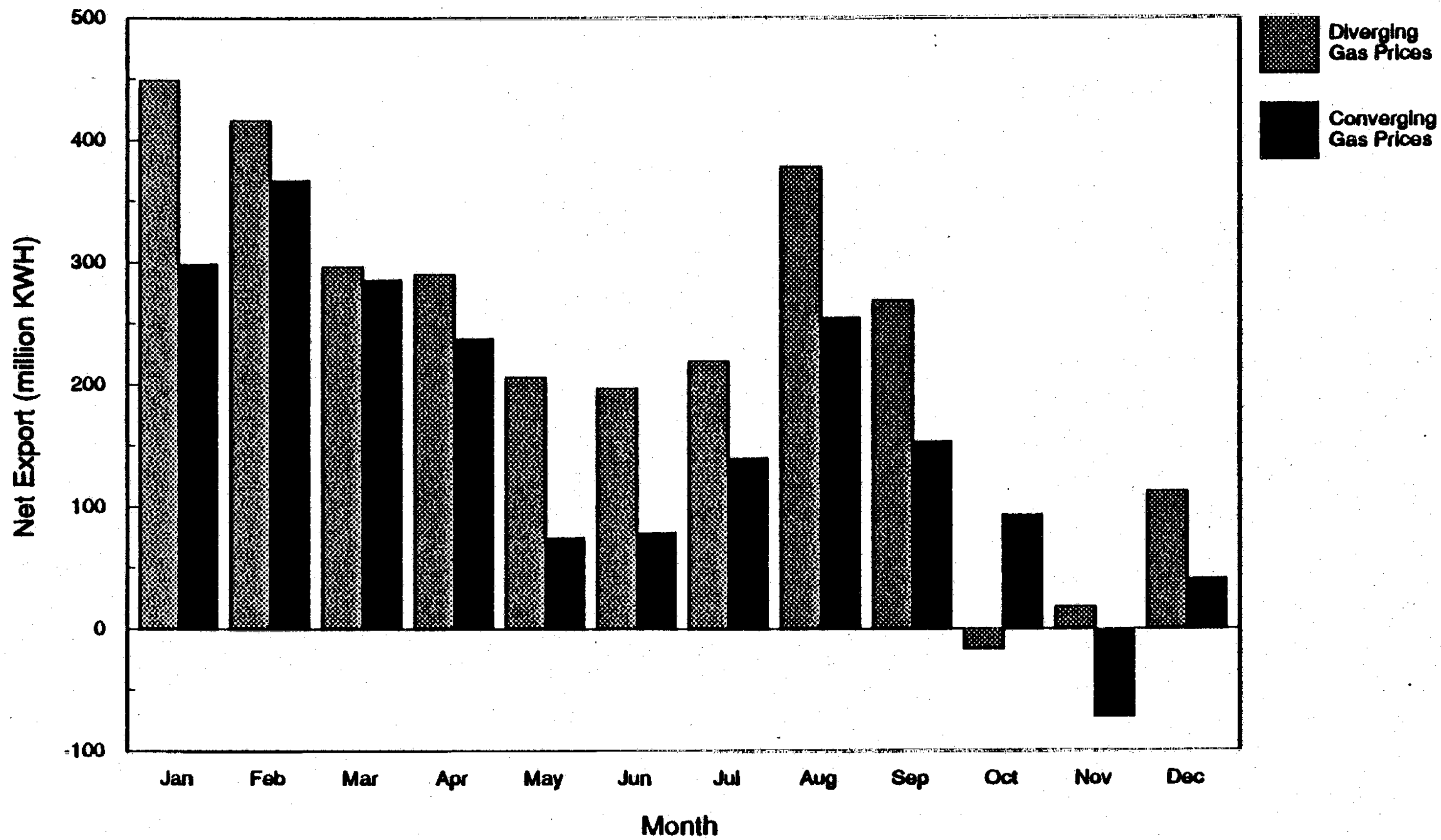


Figure 4.2-6 1990 Net Monthly Interchange : Lower Colorado River Authority

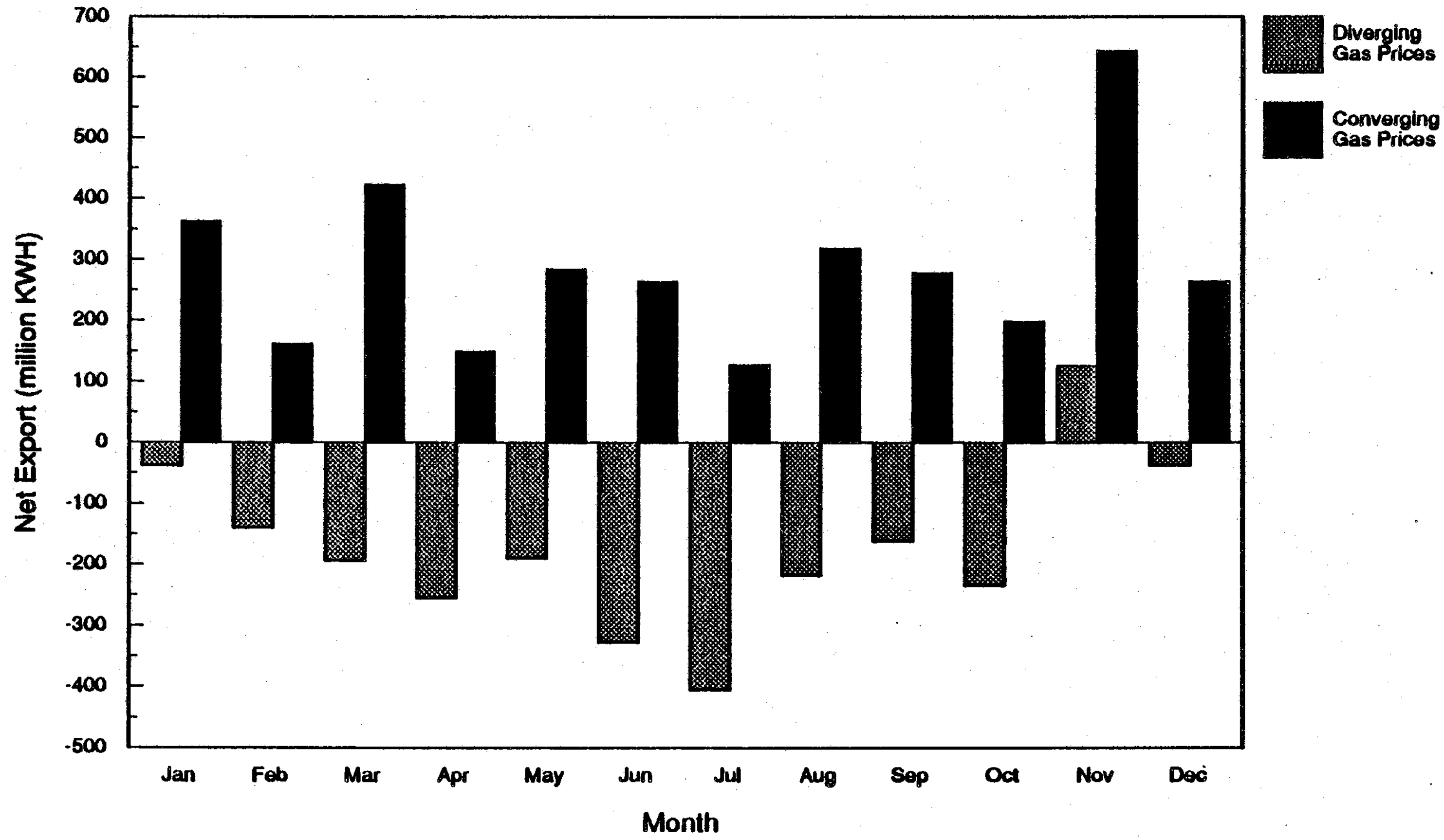


Figure 4.2-7 1990 Net Monthly Interchange :
City of San Antonio

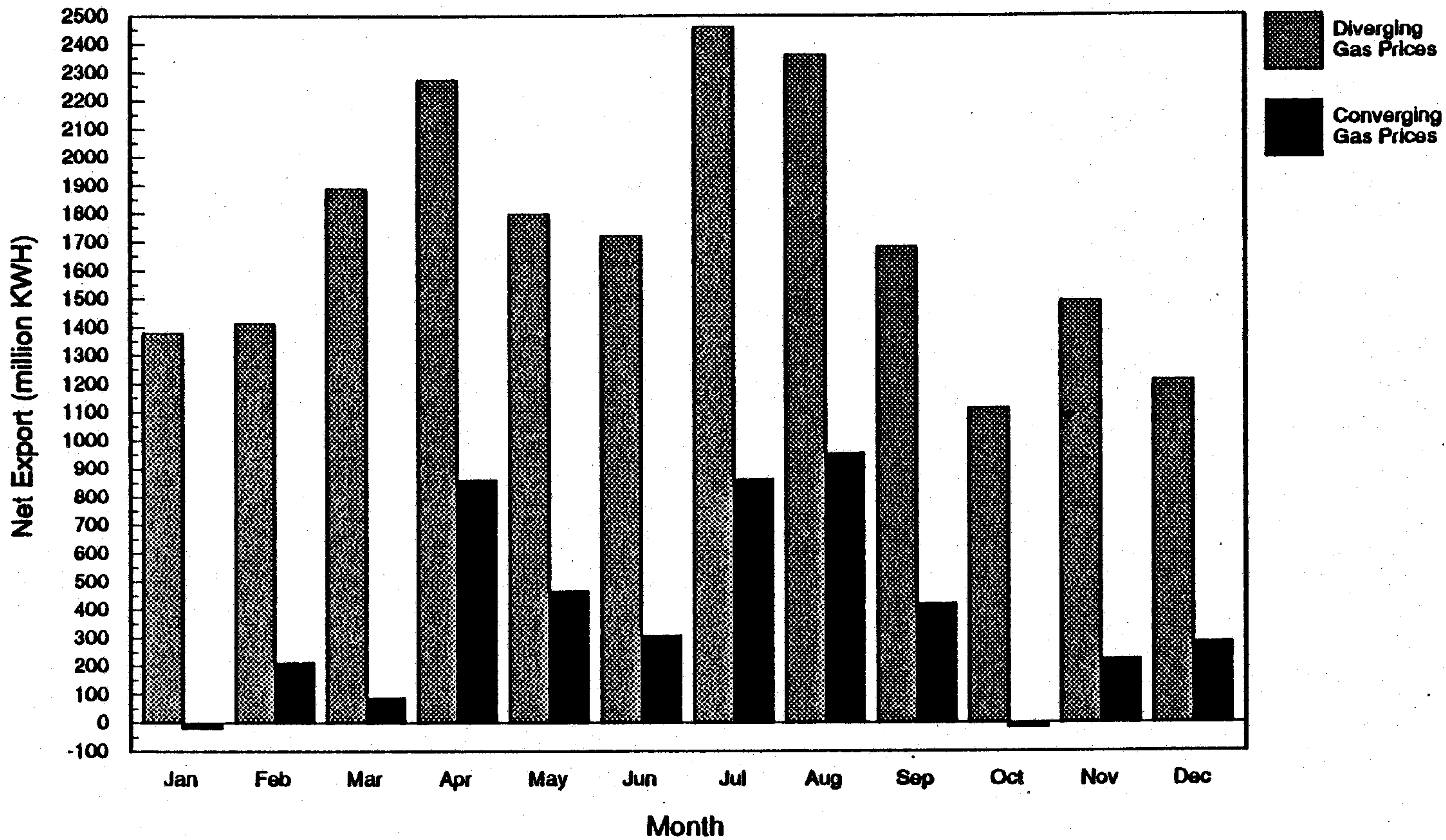


Figure 4.2-8 1990 Net Monthly Interchange :
Houst on Lighting and Power

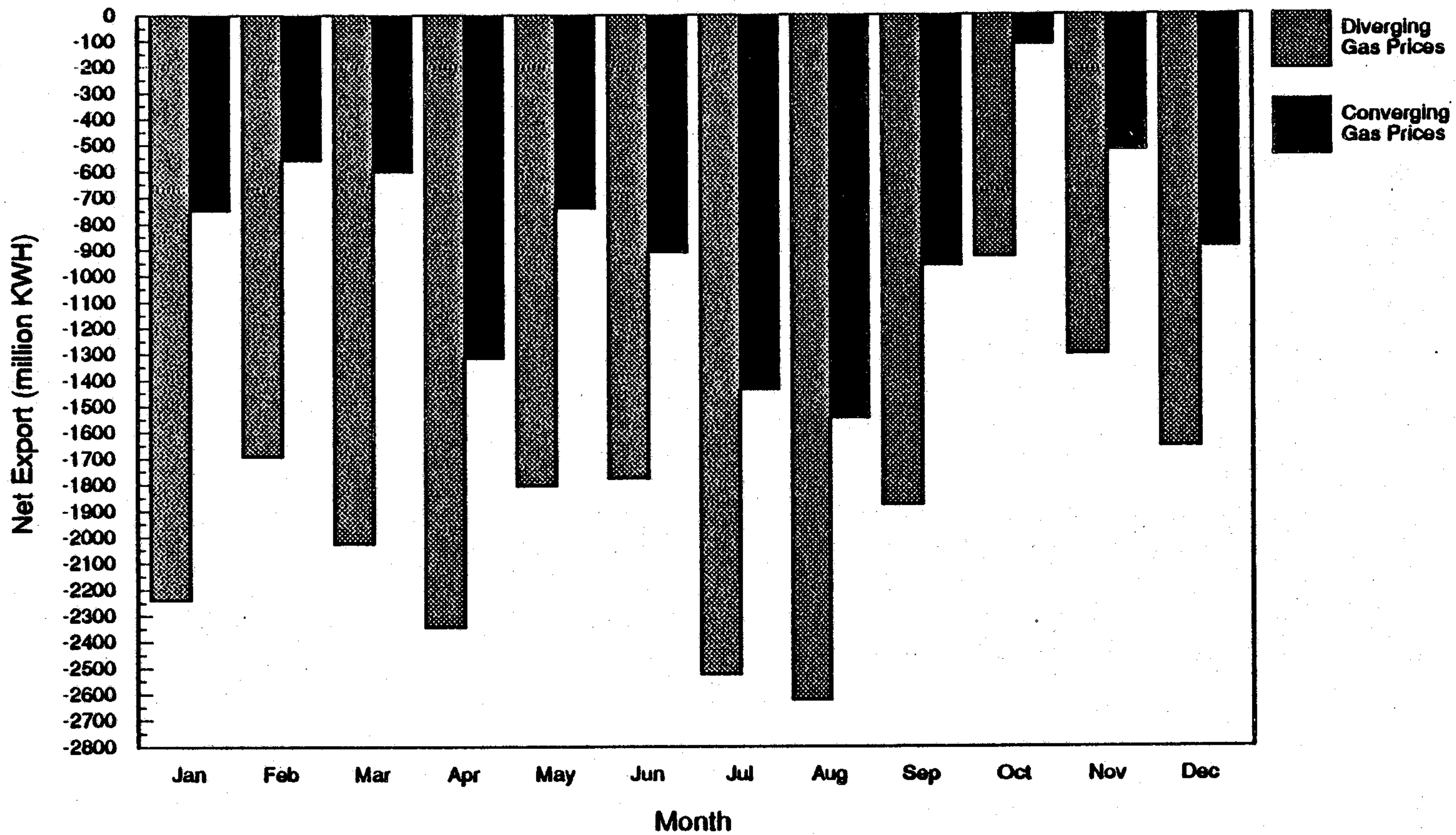


Figure 4.2-9 1990 Net Monthly Interchange :
Texas Utilities Electric Company

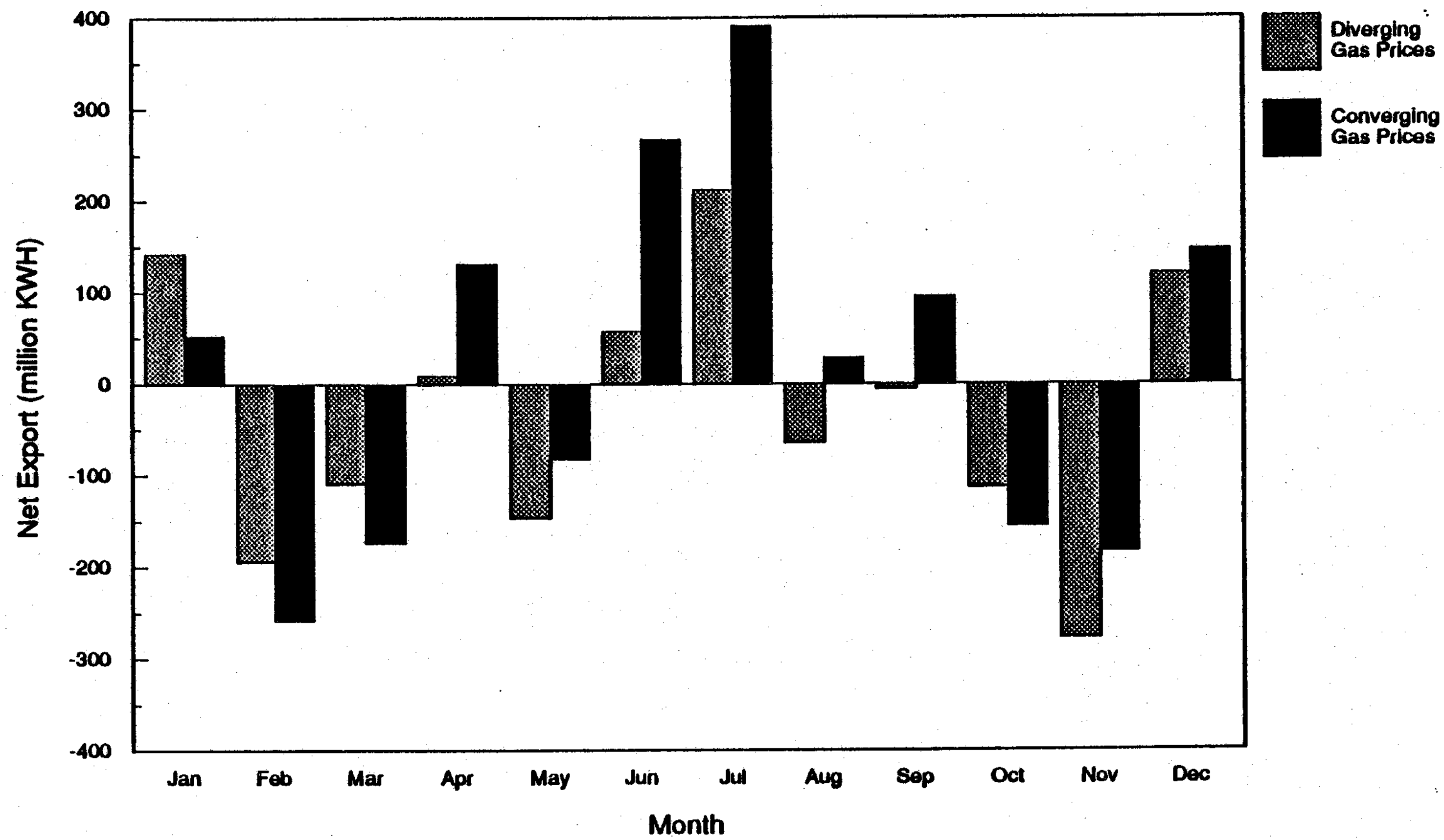


Figure 4.2-10 1990 Net Monthly Interchange :
Central & South West Company

amount in the shoulder month of September. Its net imports reach a peak during July and November. COA's ability to export during the winter months reflects it relatively low heating load and system load factor.

LCRA, under either gas price scenario, has both a low gas price and available capacity reserves and is a net exporter from January to September and in December. In October, LCRA is a small net importer assuming diverging fuel prices, but switches to a net exporter. In November, the situation is reversed. The monthly average of LCRA's net export from January through September is approximately 50% higher than the average net export of COA, a utility of similar size and location but with much different load patterns.

Under either gas price scenario, C&SW shows a mixed pattern of imports and exports. In general, the model results show net exports in the summer and winter peak months, but net imports in the spring and fall. This is apparently the result of the maintenance scheduling done by the model. In actuality, each of the four operating companies, only two of which are in ERCOT, prepare their own maintenance schedules which are reviewed by C&SW to insure that there is adequate capacity at all times for the centralized operation of the system. On an annual basis, however, the level of net imports/exports is low compared to C&SW's total load.

The monthly results for CPSB, depending on which gas price scenario is chosen, show consistenct within each scenario but divergence between them. Under the assumption of diverging gas prices, CPSB's relatively high gas price and moderate capacity reserves cause it to import relatively constant quantities of energy in every month except November. However, when converging natural gas prices are assumed, the availability of relatively efficient capacity dominates and it exports in every month of the year. This is also demonstrated in the alternative fuel price scenarios in Chapter 5, where CPSB is a net exporter in some cases and a net importer in others.

4.2.4 Fuel Savings

One of the reasons to engage in bulk power transactions is to utilize fuel more efficiently by displacing less economical generation with more economical generation. Small isolated systems are less flexible in the choice of generating units. For example, as shown in Appendix C assuming diverging gas prices, the coal units of COA are used at only a 67 percent capacity factor under own-load operation in 1990 and a 76 percent capacity factor under pool operation. For the same year, assuming converging fuel prices, these units are used at only a 66 percent capacity factor under own-load operation in 1990 and a 78 percent capacity factor under pool operation.

The comparison of fuel consumption between own-load and pool operations for 1990 and 1995 are presented in Tables 4.2-11 through 4.2-14. For either of the gas price assumptions, the coordinated operation does not result in any significant change in the total amount of fuel consumption. However, the direction of the small changes as shown in these tables for both study years form a consistent pattern with slight increases in total BTU for diverging gas prices and slight decreases in total BTU for converging fuel prices. The reason for this difference is the result of differing combinations of inter-fuel and intra-fuel substitution based on price differentials and the efficiency of different types of generating units. In general, natural gas units have lower heat rates than units with coal or lignite as their primary fuel so inter-fuel substitution from gas fired to solid fuel units produces an increase in total BTU requirements to produce the same amount of electricity. In the case of diverging fuel prices, intra-fuel substitution from an exporting utility's gas units for an importing utility's gas units can occur economically even if the

TABLE 4.2-11

Fuel Consumption in 1990:
Reference Case - Diverging Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
<u>Own-Load Operation</u>						
COA	15,128	33,813	0	0	23,529	72,470
LCRA	22,109	56,048	0	0	0	78,157
CPSB	39,132	57,023	0	0	40,532	136,687
HL&P	257,518	89,610	92,720	0	45,116	484,965
TUEC	405,933	0	409,681	226	128,464	944,304
C&SW	123,024	80,343	0	12	37,503	240,882
Total	862,845	316,837	502,401	238	275,145	1,957,466
<u>Pool Operation</u>						
COA	25,476	37,810	0	0	23,801	87,087
LCRA	43,987	64,273	0	0	0	108,260
CPSB	15,233	58,511	0	0	41,652	115,395
HL&P	422,581	126,990	96,751	0	45,817	692,139
TUEC	174,770	0	414,941	226	128,477	718,414
C&SW	123,995	76,330	0	8	37,487	237,820
Total	806,042	363,914	511,692	233	277,234	1,959,115

TABLE 4.2-12

Fuel Consumption in 1990:
Reference Case - Converging Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
Own-Load Operation						
COA	15,524	33,311	0	0	23,529	72,365
LCRA	19,924	58,556	0	0	0	78,481
CPSB	41,858	53,624	0	0	40,532	136,014
HL&P	234,993	111,618	92,720	0	45,116	484,447
TUEC	406,196	0	409,701	226	128,464	944,588
C&SW	121,855	79,737	0	12	37,499	239,102
Total	840,350	336,846	502,421	238	275,140	1,954,996
Pool Operation						
COA	9,068	38,525	0	0	23,798	71,391
LCRA	32,628	65,363	0	0	0	97,991
CPSB	67,409	60,913	0	0	41,647	169,969
HL&P	262,829	118,981	96,437	0	45,812	524,059
TUEC	291,925	0	414,275	226	128,455	834,881
C&SW	126,515	78,034	0	8	37,482	242,039
Total	790,374	361,817	510,712	233	277,195	1,940,330

TABLE 4.2-13

Fuel Consumption in 1995:
Reference Case - Diverging Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
Own-Load Operation						
COA	30,682	37,623	0	0	23,791	92,096
LCRA	22,884	79,466	0	0	0	102,349
CPSB	28,195	106,971	0	0	41,178	176,343
HL&P	252,502	134,375	182,058	0	45,843	614,778
TUEC	361,203	38,155	554,156	348	127,508	1,081,370
C&SW	156,682	92,585	0	39	37,507	286,813
Total	852,147	489,175	736,214	387	275,826	2,353,750
Pool Operation						
COA	33,443	38,703	0	0	23,803	95,949
LCRA	40,721	81,215	0	0	0	121,935
CPSB	27,089	123,970	0	0	41,655	192,714
HL&P	397,997	147,201	180,820	0	45,820	771,838
TUEC	179,912	23,835	573,905	386	128,382	906,420
C&SW	145,812	88,556	0	8	37,489	271,865
Total	824,974	503,480	754,725	393	277,149	2,360,722

TABLE 4.2-14

Fuel Consumption in 1995:
Reference Case - Converging Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
Own-Load Operation						
COA	30,683	37,623	0	0	23,791	92,097
LCRA	22,882	79,466	0	0	0	102,348
CPSB	28,195	106,971	0	0	41,178	176,343
HL&P	246,909	140,900	182,058	0	45,843	615,710
TUEC	381,454	13,486	555,735	388	127,734	1,078,797
C&SW	154,845	92,597	0	39	37,507	284,987
Total	864,968	471,042	737,793	427	276,051	2,350,282
Pool Operation						
COA	23,117	38,581	0	0	23,803	85,500
LCRA	28,043	81,014	0	0	0	109,057
CPSB	70,316	124,133	0	0	41,655	236,104
HL&P	263,447	145,204	180,611	0	45,820	635,081
TUEC	299,038	5,729	574,328	366	128,387	1,007,849
C&SW	142,234	88,239	0	8	37,489	267,970
Total	826,195	482,899	754,939	373	277,155	2,341,562

heat rate of the exporting utility's units is greater than the heat rate of the importing utility's units, provided that the exporting utility's gas price is sufficiently lower than the importing utility's gas price. In such a situation, the total BTU requirement can also increase. However, in the converging gas price case (every utility has the same gas price), intra-fuel substitution will only occur when the exporting utility's gas units have heat rates which are absolutely lower than the importing utility's gas units. In that situation, the gas BTU requirement must fall, and when that decrease exceeds the increase attributable to inter-fuel substitution, the total BTU requirement will also decrease. Obviously, the presence of inter-fuel substitution is a complicating factor, but the 1990 and 1995 results are consistent with the program logic.

As mentioned earlier, coal, lignite, and nuclear units are usually less technically efficient than gas units and need more heat to generate the same amount of electricity. However, these units typically use less scarce fuels which are more than proportionally cheaper than natural gas. In the long run, the supply of natural gas is expected to be more limited than coal, lignite, and nuclear fuels, and the displacement of natural gas with more abundant and less expensive fuels is a logical and economical choice. Figures 4.2-11 through 4.2-14 show a reduction in gas consumption by the utilities as a result of coordinated operation during the study years for both reference cases. These figures only show the shift from natural gas to coal, lignite, and nuclear fuels. Cogeneration and hydroelectric generation each have constant output under both own-load and coordinated operation and, therefore, are omitted from the figures.

It should be noted that the natural gas savings discussed here do not take into consideration the potential use of cogeneration as a substitute for conventional generation. As mentioned in chapter 3, the fuel chargeable to power associated with a typical cogeneration facility implies an effective electric heat rate of 7,645 BTU/KWH.

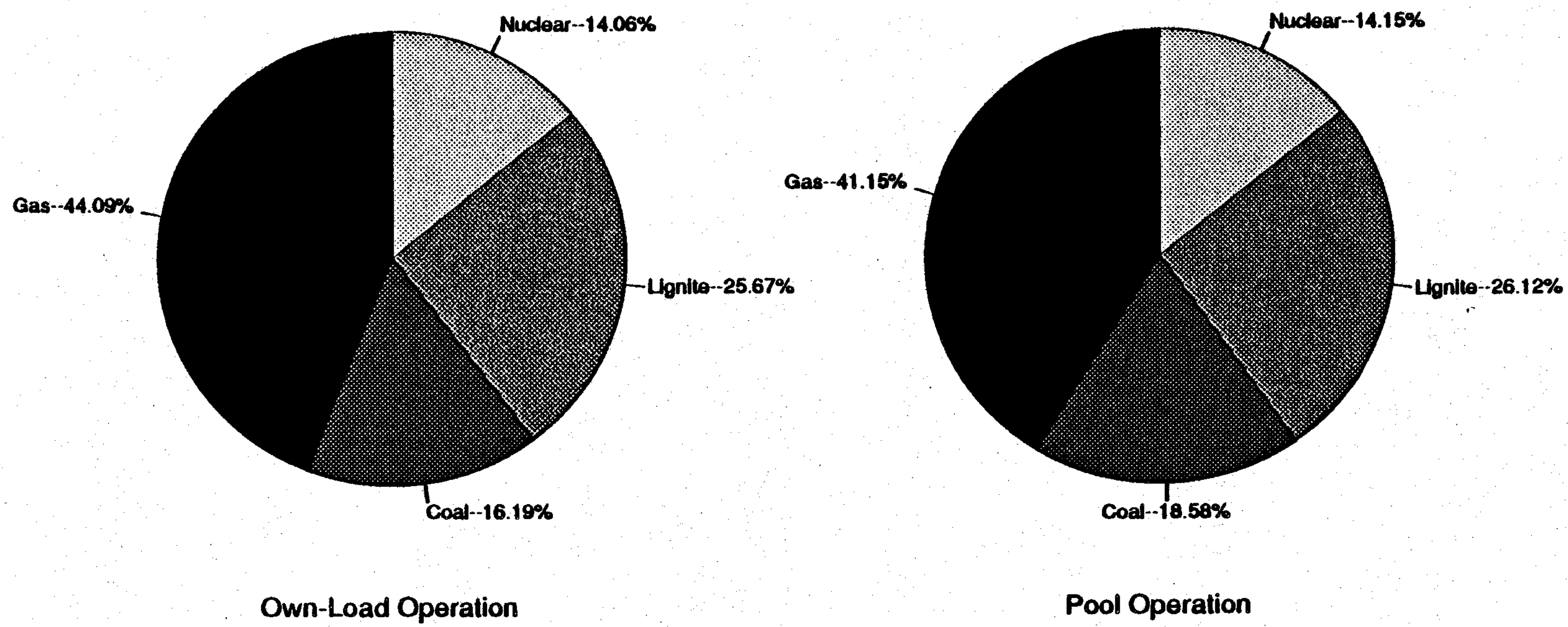


Figure 4.2-11 1990 Fuel Consumption Pattern :
Reference Case - Diverging Gas Prices

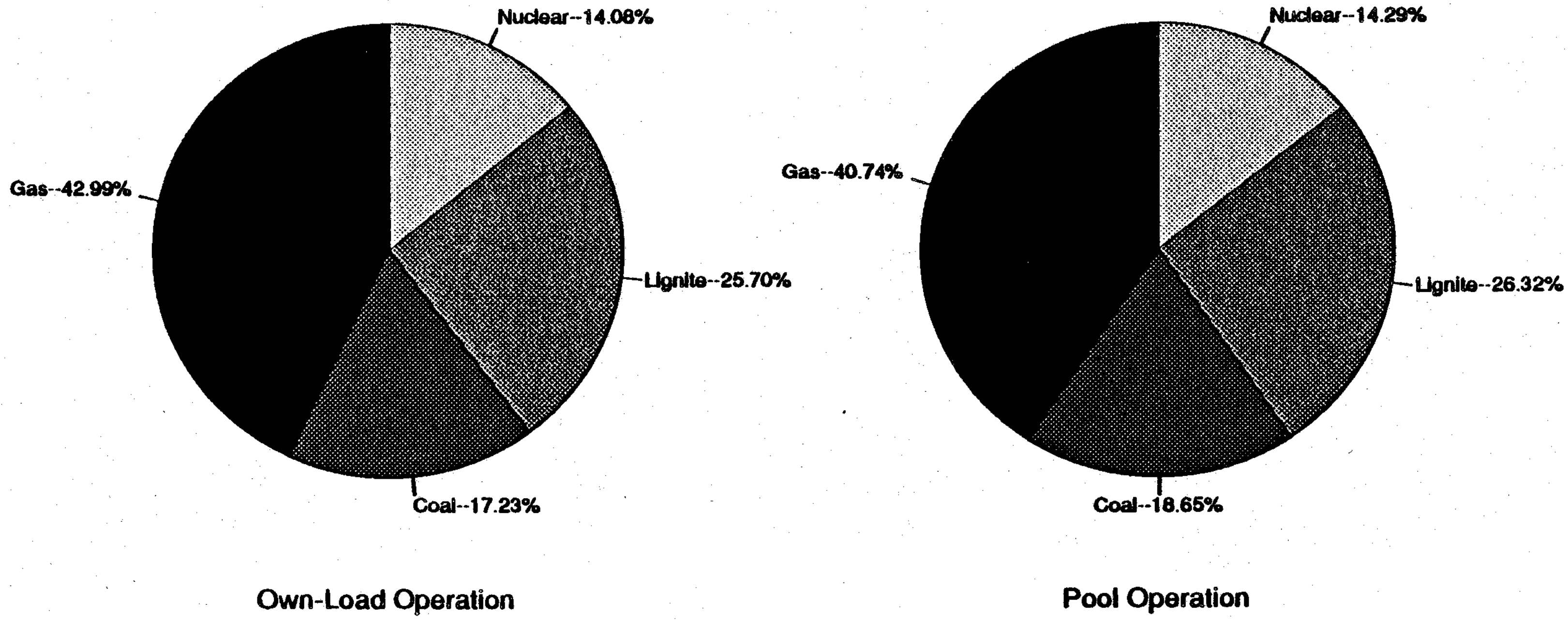


Figure 4.2-12 1990 Fuel Consumption Pattern :
Reference Case - Converging Gas Prices

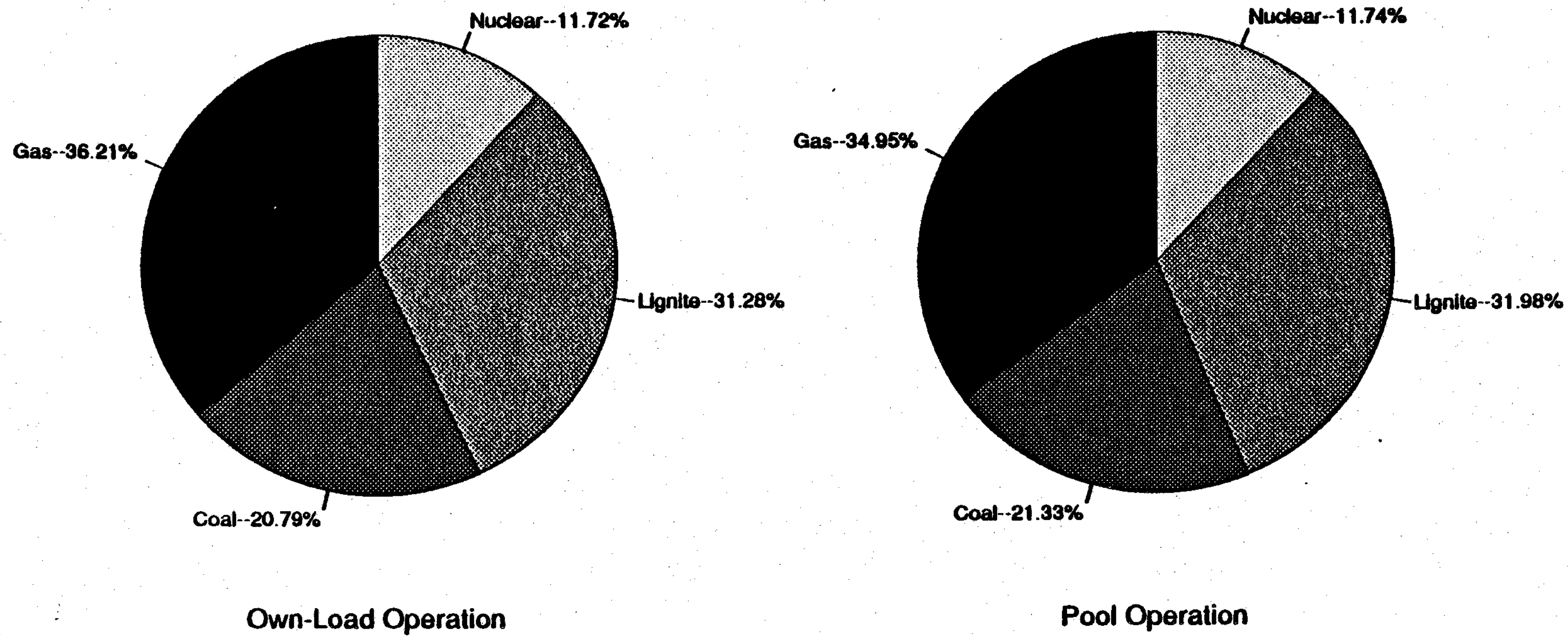


Figure 4.2-13 1995 Fuel Consumption Pattern :
Reference Case - Diverging Gas Prices

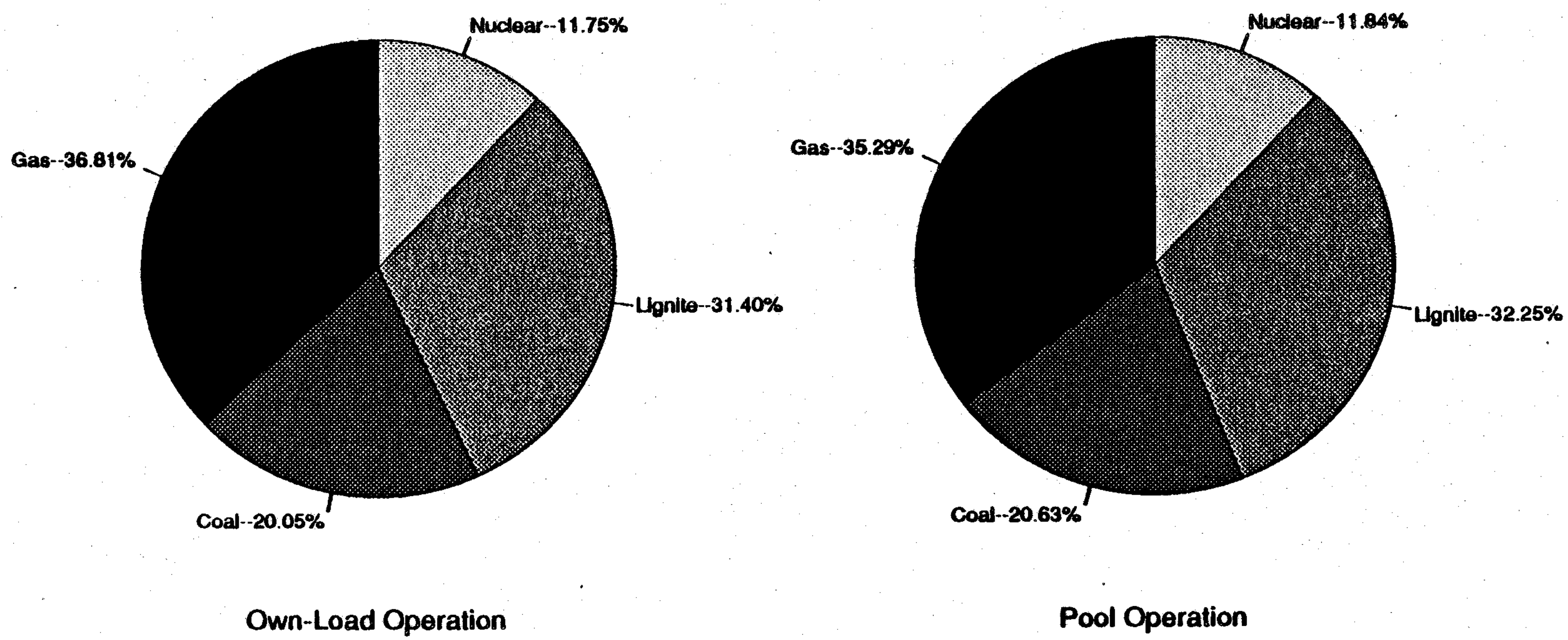


Figure 4.2-14 1995 Fuel Consumption Pattern :
Reference Case - Converging Gas Prices

The electrical energy produced by cogenerators at this effective heat rate is given in Tables 4.2-5&6 and 4.2-7&8 for 1990 and 1995, respectively. The energy listed in the column labeled "Other" for HL&P and TUEC in these tables identify cogenerated energy. These data indicate that 17,526 million KWH and 19,264 million KWH are produced by cogenerators in the years 1990 and 1995, respectively. Assuming this cogeneration displaces utility generation which operates at 10,000 BTU/KWH, the fuel savings due to cogeneration are $(10.0\text{-}7.645)\times17{,}526 = 41{,}274$ billion BTU in 1990 and $(10.0\text{-}7.645)\times19{,}264 = 45{,}367$ billion BTU in 1995. These fuel savings amount to 4.8% of the gas burned in 1990 and 5.3% of the gas burned in 1995 under diverging fuel prices; or 4.9% and 5.5%, respectively, under converging fuel prices.

4.2.5 Transmission limitations

Under normal operating conditions, the model results indicate that the transmission system is marginally adequate for ERCOT to take full advantage of opportunities for the higher levels of exchange of power associated with the reference cases assuming diverging fuel prices. However, transactions may exceed the practical limits of the system due to inadequate reserved capacity to maintain the reliability and stability of the system. One of ERCOT's fundamental concerns is that the capacity of the current and planned transmission system is designed to maintain the reliability of the ERCOT pool and, therefore, its ability to handle transactions for economic purposes is limited. The transmission capacity which appears to be available for transactions is reflected in the ERCOT loadflow reports that show very few lines loaded near their full capacities under projected normal conditions or at the lower transactions levels projected under converging fuel price assumptions. In contrast, the MAPS/MWFLOW model attempts to ship all available economical power which results in the loading of some lines to their full thermal capacities for a prolonged period, as indicated by the COA/LCRA loadflow analysis of the earlier base case for 1990. As discussed elsewhere, another limitation of the model is that it only deals with real, and not reactive, power. In effect, this assumes that there are cost free technical solutions for any reactive problems associated with higher line loading.

Tables 4.2-15 and 4.2-16 shows the list of monitored lines and their capacity limits used in the 1990 reference cases. The model compares these limits with the calculated loads during the year and calculates the percentage of time that certain load levels are attained. The last five columns of the table shows the cumulative percentage time that the monitored lines carry the load levels during the year. Under normal operating conditions, as expected in the reference cases, no lines appear to be overloaded. Actually, the majority of the monitored lines carry no more than 50 percent of their rating most of the time. However, there are some lines, such as Gideon 138/Austrop 138, which are utilized at full capacity for as long as 37 percent of the time. These lines may become critical elements and require reinforcement or upgrading to maintain the reliability of the network.

Under ERCOT's reliability criteria which consider the loading of the transmission system under contingency conditions, high levels of bulk power transactions (such as those associated with the diverging gas prices) on the transmission system may not leave enough transmission capacity reserve margin in the event of an emergency. The philosophy of having reserve capacity for a transmission system is similar to that of a generation system. Not having adequate reserves could cause serious consequences for the system. For example, if all the lines linking TUEC and HL&P were loaded at or near their full capacities, a sudden outage of a large generating unit in the TUEC service area would instantaneously cause power to be drawn from the ERCOT grid to compensate for the loss. At this instant, operators do not have immediate control over the system

TABLE 4.2-15

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

	Loadflow Data						Line	Line Loading				
	From Bus		To Bus				Rating	Under				Over
Line No.	No.	Name	No.	Name	Company		(MW)	20%	50%	80%	100%	100%
7	29	BONVIL 9	39	HEARNE 9	TMPP - TMPP		31	4.0	62.2	33.7	0.1	0.0
13	33	WTSN C 8	3392	JEWETT 138	TMPP - TMPP		81	18.9	31.6	49.5	0.0	0.0
14	39	HEARNE 9	35	HEARNE 8	TMPP - TMPP		40	0.0	0.0	37.5	62.5	0.0
17	65	SILCTY 9	39	HEARNE 9	TMPP - TMPP		36	0.1	35.5	62.7	1.7	0.0
48	126	POAGE 9	134	SEATON 9	TMPP - TMPP		35	0.0	30.4	68.7	0.9	0.0
155	523	DICY S 9	545	RENO 9	TMPP - TMPP		31	0.0	16.6	83.4	0.0	0.0
243	816	OLINGR D	818	OLINGR C	TMPP - TMPP		100	0.0	0.0	100.0	0.0	0.0
242	826	CASTLE D	814	NEWMAN D	TMPP - TMPP		60	0.0	0.0	100.0	0.0	0.0
320	1010	PERBASIN 138	1019	MOSS 138	TUEC - TUEC		143	85.5	14.2	0.3	0.0	0.0
324	1010	PERBASIN 138	1103	SANDHL T 138	TUEC - TUEC		143	89.7	10.4	0.0	0.0	0.0
326	1010	PERBASIN 138	1141	HOLT SS 138	TUEC - TUEC		143	74.6	24.5	0.9	0.0	0.0
341	1023	MID EAST 138	1116	WINDWOOD 138	TUEC - TUEC		96	0.0	39.4	57.6	3.0	0.0
351	1027	OD EHV 138	1121	GLENHAVN 138	TUEC - TUEC		143	26.5	68.5	5.0	0.0	0.0
360	1032	MRGN CRK 138	1033	MRGN CRK 69	TUEC - TUEC		60	66.9	33.1	0.0	0.0	0.0
362	1032	MRGN CRK 138	1318	CHINAGRV 138	TUEC - TUEC		143	64.0	36.0	0.0	0.0	0.0
363	1032	MRGN CRK 138	1318	CHINAGRV 138	TUEC - TUEC		143	63.5	36.5	0.0	0.0	0.0
384	1074	WINK SS 138	1159	N ANDREW 138	TUEC - TUEC		96	73.7	25.4	0.9	0.0	0.0
385	1075	WINK SS 69	1254	ODBAS SS 69	TUEC - TUEC		24	90.3	9.7	0.0	0.0	0.0
405	1122	ODESSA N 138	1123	ODESSA N 69	TUEC - TUEC		75	0.0	58.9	40.7	0.4	0.0
433	1210	MIDKIFF 138	1211	MIDKIFF 69	TUEC - TUEC		45	9.3	90.7	0.0	0.0	0.0
438	1305	SNYDER 138	1306	SNYDER 69	TUEC - TUEC		50	0.4	96.4	3.3	0.0	0.0
451	1322	BIG SPG 138	1332	COSDEN 138	TUEC - TUEC		155	71.8	13.0	15.1	0.0	0.0
357	1430	GRAHAM P 345	1030	MRGN CRK 345	TUEC - TUEC		717	76.6	23.4	0.0	0.0	0.0
358	1430	GRAHAM P 345	1030	MRGN CRK 345	TUEC - TUEC		526	47.7	52.3	0.0	0.0	0.0
494	1430	GRAHAM P 345	1436	PARKER 345	TUEC - TUEC		717	52.8	47.2	0.0	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
495	1430	GRAHAM P 345	1436	PARKER 345	TUEC - TUEC	717	52.8	47.2	0.0	0.0	0.0
503	1436	PARKER 345	1900	COM PEAK 345	TUEC - TUEC	717	20.7	18.2	49.4	11.8	0.0
551	1576	MINWL S 138	1571	ORAN 138	TUEC - TUEC	124	0.0	0.3	99.7	0.0	0.0
573	1636	DUBLIN 138	1637	DUBLIN 69	TUEC - TUEC	25	0.5	41.4	58.1	0.0	0.0
577	1640	LNGLVL M 138	1641	STPHVIL 138	TUEC - TUEC	84	3.2	22.2	74.6	0.0	0.0
568	1640	LNGLVL M 138	1624	LEON 138	TUEC - TUEC	84	7.1	31.7	61.1	0.0	0.0
592	1691	VALLEY 138	1758	PAYNE 138	TUEC - TUEC	214	2.6	90.7	6.8	0.0	0.0
642	1860	EAGLE MT 138	1957	SAGINAW 138	TUEC - TUEC	143	75.7	24.3	0.0	0.0	0.0
643	1860	EAGLE MT 138	1957	SAGINAW 138	TUEC - TUEC	105	9.3	74.5	16.0	0.2	0.0
649	1873	BENBRK 345	1890	DECORDVA 345	TUEC - TUEC	717	22.2	54.6	23.3	0.0	0.0
651	1874	BENBRK A 138	1955	CALMONT 138	TUEC - TUEC	210	0.1	33.5	55.3	11.1	0.0
654	1875	BENBRK B 138	2164	HEMPHILL 138	TUEC - TUEC	143	2.0	45.0	45.7	7.3	0.0
834	2385	N LAKE 138	2380	CLT NW 138	TUEC - TUEC	224	96.2	3.8	0.1	0.0	0.0
835	2385	N LAKE 138	2380	CLT NW 138	TUEC - TUEC	214	95.3	4.4	0.3	0.0	0.0
861	2406	NORWD 345	2407	NORWDDPL 138	TUEC - TUEC	450	0.2	35.3	55.5	9.0	0.0
934	2461	ROYSE 345	2462	ROYSE 138	TUEC - TUEC	450	0.3	89.1	10.6	0.0	0.0
943	2466	ALLEN SS 345	2467	ALLEN SS 138	TUEC - TUEC	450	0.0	78.1	21.9	0.0	0.0
949	2468	RENER 345	2470	RENERTPL 138	TUEC - TUEC	450	0.0	75.0	25.0	0.0	0.0
1004	2756	MSQT E 138	2754	MSQT W 138	TUEC - TUEC	326	1.7	98.3	0.0	0.0	0.0
1053	3118	LUFKINSS 138	3340	LUFKIN 138	TUEC - TUEC	48	5.4	19.5	32.7	42.4	0.0
1062	3125	TDAD TR	3126	TDAD 6 G	TUEC - TUEC	265	98.4	1.0	0.5	0.1	0.0
1063	3125	TDAD TR	3127	TRINIDAD 138	TUEC - TUEC	265	0.2	51.7	46.5	1.6	0.0
1104	3354	CROCKETT 138	3392	JEWETT 138	TUEC - TUEC	84	19.2	41.2	36.6	3.0	0.0
1107	3380	BIGBRN 345	3390	JEWETT S 345	TUEC - TUEC	956	33.5	57.8	8.6	0.0	0.0
1108	3380	BIGBRN 345	3391	JEWETT N 345	TUEC - TUEC	956	20.8	50.8	28.4	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line No.	From Bus No.	From Bus Name	To Bus No.	To Bus Name	Company	Rating (MW)	Under 20%	50%	80%	100%	Over 100%
1142	3410	LAKE CRK 138	3436	WACO W 138	TUEC - TUEC	210	3.7	87.0	9.2	0.0	0.0
1143	3410	LAKE CRK 138	3438	WACO E 138	TUEC - TUEC	210	2.5	85.9	11.6	0.0	0.0
1140	3414	TEMP SS 345	3409	LAKE CRK 345	TUEC - TUEC	956	91.0	9.0	0.0	0.0	0.0
1131	3414	TEMP SS 345	3405	T HOUSE 345	TUEC - TUEC	956	90.0	10.0	0.0	0.0	0.0
1158	3429	SANDOW 345	3430	SANDOW 138	TUEC - TUEC	450	22.6	15.9	61.4	0.0	0.0
1162	3430	SANDOW 138	3650	ELGIN SS 138	TUEC - TUEC	84	15.2	35.5	33.7	15.6	0.0
1192	3627	KILLFH T 138	3629	KILL FHW 138	TUEC - TUEC	124	54.6	45.2	0.2	0.0	0.0
1209	3669	RNDRK WH 138	3668	RNDRK 138	TUEC - TUEC	124	45.2	45.7	9.1	0.0	0.0
1217	3683	MINERVA 138	3684	MINERVA 69	TUEC - TUEC	30	0.1	11.8	60.0	28.2	0.0
1230	4009	ALIEF 8 138	4487	W A P 8 138	HLP - HLP	337	12.2	46.1	35.9	5.7	0.0
1258	4039	BAMMEL 8 138	4467	N BELT 8 138	HLP - HLP	337	100.0	0.0	0.0	0.0	0.0
1303	4067	BADSCH 8 138	4714	VLASCO 8 138	HLP - HLP	168	11.8	87.0	1.2	0.0	0.0
1331	4112	CEDARP 5 345	4383	KING 5 345	HLP - HLP	872	4.2	22.0	44.5	29.4	0.0
1341	4133	H O C A9 69	4135	H O C 8 138	HLP - HLP	128	40.1	59.8	0.1	0.0	0.0
1391	4219	ELDORA 8 138	4546	P H R S8 138	HLP - HLP	337	0.0	47.4	52.6	0.0	0.0
1466	4323	HUMBLE 8 138	4685	TRSWIG 8 138	HLP - HLP	168	13.7	41.4	44.4	0.4	0.0
1492	4463	NATCYL 8 138	4487	W A P 8 138	HLP - HLP	337	21.8	54.1	24.1	0.0	0.0
1516	4675	TOMBAL 8 138	4507	PINHUR 8 138	HLP - HLP	337	100.0	0.0	0.0	0.0	0.0
1558	4675	TOMBAL 8 138	4676	TOMBAL 5 345	HLP - HLP	600	99.1	0.9	0.0	0.0	0.0
1551	4684	TEXGLF 8 138	4620	S LANE 8 138	HLP - HLP	168	13.2	65.6	21.3	0.0	0.0
1574	4740	WHITOKE8 138	4741	WHITOK 9 69	HLP - HLP	100	71.1	28.9	0.0	0.0	0.0
1656	5211	HILL CTY 345	5915	SO TEX 5 345	CPSB - CPSB	1076	32.5	67.2	0.4	0.0	0.0
1660	5225	HONDO 138	5819	HONDOCR8	CPSB - CPSB	81	90.4	9.6	0.0	0.0	0.0
1690	5371	SKYLINE 345	5370	SKYLINE 138	CPSB - CPSB	480	46.6	48.2	5.3	0.0	0.0
1691	5371	SKYLINE 345	5370	SKYLINE 138	CPSB - CPSB	480	46.6	48.2	5.3	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1692	5435	TUTTLE 138	5370	SKYLINE 138	CPSB - CPSB	478	34.2	64.8	1.0	0.0	0.0
1957	6232	ABMULCK4 138	6235	ABMULCK7 345	WTU - WTU	250	89.3	10.7	0.0	0.0	0.0
2108	7000	FERGSNGN	7126	FERGUSN8 138	LCRA - LCRA	480	55.1	10.2	3.4	31.2	0.0
2111	7006	GID GEN3	7310	GIDEON 8 138	LCRA - LCRA	380	33.8	3.8	23.3	39.1	0.0
2112	7010	FPP GEN1	7056	FPP 5 345	LCRA - LCRA	600	16.3	6.3	20.5	57.0	0.0
2114	7012	FPP GEN3	7056	FPP 5 345	LCRA - LCRA	2114	16.3	10.3	25.7	47.6	0.0
2129	7040	AUSTROP5 345	7328	AUSTROP8 138	LCRA - LCRA	2129	53.8	46.2	0.0	0.0	0.0
2127	7042	ZORN 5 345	7040	AUSTROP5 345	LCRA - LCRA	2127	99.5	0.5	0.0	0.0	0.0
2144	7064	LAMPSAS8 138	7061	COPP CV8 138	LCRA - LCRA	2144	74.9	25.0	0.1	0.0	0.0
2145	7064	LAMPSAS8 138	7070	GOLDTWT8 138	LCRA - LCRA	2145	24.1	28.3	38.5	8.1	1.0
2166	7107	WIRTZ 9 69	7110	WIRTNUT1	LCRA - LCRA	2166	47.3	20.3	32.4	0.0	0.0
2170	7119	PITSBRG9 69	7114	CASTELL9 69	LCRA - LCRA	2170	40.6	36.7	22.7	0.1	0.0
2203	7178	MARION 8 138	7176	COMAL 8 138	LCRA - LCRA	2203	5.3	92.1	2.6	0.0	0.0
2204	7178	MARION 8 138	7176	COMAL 8 138	LCRA - LCRA	64	0.6	42.3	56.2	1.0	0.0
2215	7192	SANMRCS8 138	7200	CANYON 8 138	LCRA - LCRA	101	28.2	61.9	9.9	0.0	0.0
2221	7200	CANYON 8 138	7498	BUDA 8 138	LCRA - LCRA	101	62.8	37.2	0.0	0.0	0.0
2224	7202	HICROSS8 138	7498	BUDA 8 138	LCRA - LCRA	101	70.0	27.0	3.0	0.0	0.0
2255	7264	PETERS 8 138	7270	BELVILE8 138	LCRA - LCRA	171	43.6	46.8	9.6	0.0	0.0
2258	7286	FAYET 8 138	7270	BELVILE8 138	LCRA - LCRA	171	94.8	5.2	0.0	0.0	0.0
2284	7310	GIDEON 8 138	7328	AUSTROP8 138	LCRA - LCRA	171	4.3	32.0	26.8	37.0	0.0
2285	7310	GIDEON 8 138	7328	AUSTROP8 138	LCRA - LCRA	171	11.6	32.3	56.1	0.0	0.0
2299	7350	MORMON 8 138	7352	LAGOVST8 138	LCRA - LCRA	171	88.8	11.2	0.0	0.0	0.0
2355	8121	BLESSNG4 138	8127	L.CITYM4 138	CPL - CPL	161	89.5	10.5	0.0	0.0	0.0
2353	8123	BLESSNG6 345	8121	BLESSNG4 138	CPL - CPL	600	24.0	71.2	4.7	0.0	0.0
2354	8125	LOLITA 4 138	8121	BLESSNG4 138	CPL - CPL	216	50.0	46.1	3.9	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
2375	8152	CARB-SD4 138	8144	AIRCO 4 138	CPL - CPL	161	10.7	74.1	15.3	0.0	0.0
2387	8162	COLETO 4 138	8186	KENDYSW4 138	CPL - CPL	216	18.5	58.0	23.5	0.0	0.0
2399	8172	VICTRA 4 138	8183	THOMSTN4 138	CPL - CPL	216	44.3	46.0	9.7	0.0	0.0
2400	8172	VICTRA 4 138	8452	LNHILL 4 138	CPL - CPL	127	42.8	57.1	0.2	0.0	0.0
2405	8183	THOMSTN4 138	8192	C.LCRA 4 138	CPL - CPL	216	46.1	44.7	9.2	0.0	0.0
2407	8184	KENDYSW2 69	8188	KENEDY 2 69	CPL - CPL	41	23.1	74.4	2.5	0.0	0.0
2428	8214	ARTESIA2 69	8280	ASHERTN2 69	CPL - CPL	41	99.7	0.3	0.0	0.0	0.0
2440	8234	UVALDE 4 138	8246	ASPHALT4 138	CPL - CPL	82	30.7	64.1	5.2	0.0	0.0
2445	8246	ASPHALT4 138	8252	BRACKVL4 138	CPL - CPL	82	34.1	61.9	4.0	0.0	0.0
2455	8274	CNC.W T4 138	8283	ASHERTN4 138	CPL - CPL	82	24.8	68.1	7.1	0.0	0.0
2457	8283	ASHERTN4 138	8293	LAREDO 4 138	CPL - CPL	127	82.0	17.8	0.3	0.0	0.0
2464	8293	LAREDO 4 138	8297	BRUNI 4 138	CPL - CPL	82	51.7	48.3	0.0	0.0	0.0
2466	8297	BRUNI 4 138	8510	FALF 4 138	CPL - CPL	82	22.1	77.9	0.0	0.0	0.0
2468	8300	RAYVILE2 69	8302	RAYVILE4 138	CPL - CPL	37	0.0	57.1	41.4	1.5	0.0
2475	8310	LAPALM 2 69	8314	LAPALM 4 138	CPL - CPL	93	0.1	90.4	9.6	0.0	0.0
2476	8310	LAPALM 2 69	8314	LAPALM 4 138	CPL - CPL	93	0.0	85.1	14.9	0.0	0.0
2534	8392	BATES 4 138	8399	GARZA 4 138	CPL - CPL	82	89.5	10.5	0.0	0.0	0.0
2467	8395	FALCON 4 138	8299	ZAPATA 4 138	CPL - CPL	82	78.3	21.8	0.0	0.0	0.0
2535	8395	FALCON 4 138	8399	GARZA 4 138	CPL - CPL	82	100.0	0.0	0.0	0.0	0.0
2537	8403	T.RIVR 4 138	8400	T.RIVR 2 69	CPL - CPL	37	2.3	92.2	5.4	0.0	0.0
2631	8500	ALICE 2 69	8505	FREER 2 69	CPL - CPL	41	10.1	88.3	1.6	0.0	0.0
2568	8439	N BAY 2 69	8468	HIWAY9 2 69	CPL - CPL	58	62.4	34.4	3.2	0.0	0.0
2569	8439	N BAY 2 69	8871	AVRYP1-2 69	CPL - CPL	71	69.1	30.9	0.0	0.0	0.0
2657	9073	HOLMAN 345	9074	LYTTON 345	COA - COA	1075	0.1	55.8	43.4	0.8	0.0
2682	9124	KINGSBRY 138	9125	KINGSBRY 69	COA - COA	220	84.3	15.7	0.0	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
2686	9124	KINGSBRY 138	9291	WHELESS 138	COA - COA	350	91.6	8.4	0.0	0.0	0.0
2689	9128	NORTHLND 138	9129	NORTHLND 69	COA - COA	220	34.8	64.5	0.6	0.0	0.0
2697	9132	SEAHOLM 138	9287	WARREN 138	COA - COA	215	100.0	0.0	0.0	0.0	0.0
2678	9147	HICROSS 138	9120	BURLESON 138	COA - COA	215	46.1	53.8	0.1	0.0	0.0
2718	9187	DECKER 138	9271	SPRINKLE 138	COA - COA	430	91.3	8.7	0.0	0.0	0.0
2666	9271	SPRINKLE 138	9079	MCNEIL 138	COA - COA	430	97.3	2.8	0.0	0.0	0.0
1112	3390	JEWETT S 345	4401	LIMEST 5 345	TUEC - HLP	1300	29.5	70.5	0.0	0.0	0.0
1113	3390	JEWETT S 345	4737	T H W 5 345	TUEC - HLP	762	20.7	48.3	31.0	0.0	0.0
1116	3391	JEWETT N 345	4401	LIMEST 5 345	TUEC - HLP	1300	100.0	0.0	0.0	0.0	0.0
1117	3391	JEWETT N 345	4676	TOMBAL 5 345	TUEC - HLP	850	27.8	59.5	12.7	0.0	0.0
1124	3400	TWIN OAK 345	4401	LIMEST 5 345	TUEC - HLP	1300	25.8	73.6	0.6	0.0	0.0
1125	3400	TWIN OAK 345	4401	LIMEST 5 345	TUEC - HLP	1300	25.8	73.6	0.6	0.0	0.0
1126	3400	TWIN OAK 345	4562	SALHLP 5 345	TUEC - HLP	1300	82.6	17.4	0.0	0.0	0.0
1127	3400	TWIN OAK 345	4737	T H W 5 345	TUEC - HLP	850	45.6	54.3	0.0	0.0	0.0
1109	3386	NAVAR SS 345	4401	LIMEST 5 345	TUEC - HLP	1650	11.4	69.4	19.3	0.0	0.0
1110	3386	NAVAR SS 345	4401	LIMEST 5 345	TUEC - HLP	1650	11.4	69.4	19.3	0.0	0.0
1061	3124	TRINDAD2 345	4428	MALKOF 5 345	TUEC - HLP	1650	100.0	0.0	0.0	0.0	0.0
1075	3130	FOR GROV 345	4428	MALKOF 5 345	TUEC - HLP	1650	100.0	0.0	0.0	0.0	0.0
327	1010	PERBASIN 138	6655	BARRILA4 138	TUEC - WTU	158	96.5	3.5	0.0	0.0	0.0
457	1339	ESKOTA 138	6260	ABSOUTH4 138	TUEC - WTU	65	18.4	48.1	29.7	3.8	0.0
462	1340	ESKOTA 69	6247	TRENT 2 69	TUEC - WTU	33	70.3	29.7	0.0	0.0	0.0
475	1398	RADIUM M 138	6180	RADIUM 2 69	TUEC - WTU	63	92.4	7.6	0.0	0.0	0.0
487	1425	FISHRDSS 345	6100	OKLAEHV7 345	TUEC - WTU	1072	63.2	36.1	0.6	0.0	0.0
542	1538	ELECTRA 69	6075	WAGONER2 69	TUEC - WTU	33	71.6	28.4	0.0	0.0	0.0
569	1624	LEON 138	6310	PUTTAP 4 138	TUEC - WTU	84	40.1	59.1	0.8	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
571	1625	LEON 2 69	6311	CISCO 2 69	TUEC - WTU	33	55.8	44.2	0.0	0.0	0.0
540	1533	BOMARTON 69	6107	MUNDAY 2 69	TUEC - WTU	42	100.0	0.0	0.0	0.0	0.0
467	1371	MURRAY M 138	6161	PTCREEK4 138	TUEC - WTU	155	90.7	9.3	0.0	0.0	0.0
474	1398	RADIUM M 138	6161	PTCREEK4 138	TUEC - WTU	149	87.9	12.1	0.0	0.0	0.0
359	1030	MRGN CRK 345	6235	ABMULCK7 345	TUEC - WTU	1072	85.0	15.0	0.0	0.0	0.0
496	1430	GRAHAM P 345	6235	ABMULCK7 345	TUEC - WTU	1072	100.0	0.0	0.0	0.0	0.0
463	1352	CHALK 69	6436	STRLGCO2 69	TUEC - WTU	33	68.6	28.1	3.3	0.0	0.0
1159	3429	SANDOW 345	7040	AUSTROP5 345	TUEC - LCRA	956	80.5	19.6	0.0	0.0	0.0
1160	3429	SANDOW 345	7040	AUSTROP5 345	TUEC - LCRA	1072	85.4	14.6	0.0	0.0	0.0
1207	3665	PFLGRVIL 138	7332	ELGIN 8 138	TUEC - LCRA	214	38.9	61.1	0.0	0.0	0.0
1208	3665	PFLGRVIL 138	7334	MCNEIL 8 138	TUEC - LCRA	214	59.3	40.7	0.0	0.0	0.0
1194	3630	COPPERCV 138	7061	COPP CV8 138	TUEC - LCRA	124	62.9	33.8	3.3	0.0	0.0
584	1655	BRNWD SS 138	7070	GOLDTWT8 138	TUEC - LCRA	127	47.8	51.3	0.9	0.0	0.0
1212	3672	RNDRK S 138	7334	MCNEIL 8 138	TUEC - LCRA	214	65.2	26.4	8.4	0.0	0.0
1211	3669	RNDRK WH 138	7346	GABRIEL8 138	TUEC - LCRA	214	84.4	15.6	0.0	0.0	0.0
1218	3687	JARRELL 138	7346	GABRIEL8 138	TUEC - LCRA	214	99.7	0.3	0.0	0.0	0.0
11	3682	MILANO M 138	32	RBRTSN 8	TUEC - TMPP	84	67.4	23.3	8.9	0.5	0.0
115	1576	MINWL S 138	331	MILLER 8	TUEC - TMPP	215	0.0	0.0	100.0	0.0	0.0
316	1853	ROANOKE 345	988	W.DENT B	TUEC - TMPP	1494	100.0	0.0	0.0	0.0	0.0
309	2461	ROYSE 345	970	BEN DV B	TUEC - TMPP	1016	97.8	2.2	0.0	0.0	0.0
80	3406	ELM MOTT 345	240	WHITNY 5	TUEC - TMPP	1072	100.0	0.0	0.0	0.0	0.0
604	1695	MOSES 345	5925	DC-EAST	TUEC - DCSPP	1078	100.0	0.0	0.0	0.0	0.0
1513	4494	PETERS 8 138	7264	PETERS 8 138	HLP - LCRA	340	95.8	4.2	0.0	0.0	0.0
1540	4562	SALHLP 5 345	7058	SALEM 5 345	HLP - LCRA	1000	89.7	10.3	0.0	0.0	0.0
1552	4620	S LANE 8 138	8127	L.CITYM4 138	HLP - CPL	600	99.7	0.3	0.0	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1377	4192	DOW345 5 345	5915	SO TEX 5 345	HLP - STP	872	82.4	17.6	0.0	0.0	0.0
1507	4488	W A P 5 345	5915	SO TEX 5 345	HLP - STP	872	68.7	31.3	0.0	0.0	0.0
304	4383	KING 5 345	967	GIBCRK B	HLP - TMPP	1300	82.5	17.5	0.0	0.0	0.0
305	4477	OBRIEN 5 345	967	GIBCRK B	HLP - TMPP	850	59.7	40.2	0.0	0.0	0.0
1657	5211	HILL CTY 345	7044	MARION 5 345	CPSB - LCRA	1076	98.4	1.6	0.0	0.0	0.0
1695	5371	SKYLINE 345	7044	MARION 5 345	CPSB - LCRA	1076	99.0	1.0	0.0	0.0	0.0
1649	5200	HELOTES 138	7151	CICO 8 138	CPSB - LCRA	215	91.4	8.6	0.0	0.0	0.0
1670	5260	LEON CR1 138	8203	PLESTN 4 138	CPSB - CPL	110	92.3	7.7	0.0	0.0	0.0
1632	5155	FLORESVI 138	8186	KENDYSW4 138	CPSB - CPL	161	71.4	28.2	0.3	0.0	0.0
1696	5371	SKYLINE 345	8455	LNHILL 6 345	CPSB - CPL	1076	99.7	0.3	0.0	0.0	0.0
1656	5211	HILL CTY 345	5915	SO TEX 5 345	CPSB - STP	1076	32.5	67.2	0.4	0.0	0.0
1694	5371	SKYLINE 345	5915	SO TEX 5 345	CPSB - STP	1076	29.9	69.6	0.4	0.0	0.0
1660	5225	HONDO 138	5819	HONDOCR8	CPSB- STCMEC	81	90.4	9.6	0.0	0.0	0.0
2012	6391	FRDONIT2 69	7114	CASTELL9 69	WTU - LCRA	44	57.3	42.0	0.6	0.0	0.0
2014	6392	FREDPHT2 69	7130	GILLSPE9 69	WTU - LCRA	33	50.9	49.1	0.0	0.0	0.0
2011	6390	MASON4 138	7132	GILLSPE8 138	WTU - LCRA	160	26.1	65.9	8.0	0.0	0.0
2060	6513	SONORA 2 69	8239	FRSRNCH2 69	WTU - CPL	41	98.8	1.2	0.0	0.0	0.0
2062	6515	SONORA 4 138	8259	CTHRNR 4 138	WTU - CPL	158	89.1	10.9	0.0	0.0	0.0
2074	6567	RGECCOM2 69	8253	HAMILTN2 69	WTU - CPL	41	67.4	32.6	0.0	0.0	0.0
1895	6100	OKLAEHV7 345	9035	VVIEWDC	WTU - COA	200	24.9	75.1	0.0	0.0	0.0
2244	7244	CUERO 8 138	8192	C.LCRA 4 138	LCRA - CPL	500	98.5	1.5	0.0	0.0	0.0
2254	7258	GLIDDEN8 138	8109	CPL-GLN4 138	LCRA - CPL	216	100.0	0.0	0.0	0.0	0.0
2131	7040	AUSTROP5 345	9078	MCNEIL 345	LCRA - COA	1195	73.6	26.4	0.0	0.0	0.0
2141	7056	FPP 5 345	9073	HOLMAN 345	LCRA - COA	1076	35.1	63.8	1.1	0.0	0.0
2225	7202	HICROSS8 138	9147	HICROSS 138	LCRA - COA	287	63.3	36.6	0.1	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
2288	7328	AUSTROP8 138	9154	WEBERVIL 138	LCRA - COA	430	5.4	49.8	44.8	0.0	0.0
2291	7334	MCNEIL 8 138	9079	MCNEIL 138	LCRA - COA	480	87.4	12.6	0.0	0.0	0.0
2130	7040	AUSTROP5 345	9074	LYTTON 345	LCRA - COA	1076	100.0	0.0	0.0	0.0	0.0
2136	7042	ZORN 5 345	9074	LYTTON 345	LCRA - COA	1076	93.0	7.0	0.0	0.0	0.0
2295	7338	AUSTIN 9 69	9140	AUSTNDAM 69	LCRA - COA	108	100.0	0.0	0.0	0.0	0.0
28	7044	MARION 5 345	52	SMIGL B5	LCRA - TMPP	1075	100.0	0.0	0.0	0.0	0.0
29	7044	MARION 5 345	52	SMIGL B5	LCRA - TMPP	1075	100.0	0.0	0.0	0.0	0.0
45	7345	GABRIEL9 69	123	JARREL 9	LCRA - TMPP	43	73.7	26.3	0.0	0.0	0.0
1846	8123	BLESSNG6 345	5915	SO TEX 5 345	CPL - STP	1076	66.5	33.5	0.0	0.0	0.0
1847	8455	LNHILL 6 345	5915	SO TEX 5 345	CPL - STP	1076	17.7	77.9	4.3	0.0	0.0
1707	8172	VICTRA 4 138	5502	RAYBRN 8	CPL - STCMEC	160	27.7	61.0	11.0	0.2	0.0
1724	8121	BLESSNG4 138	5546	DNVG 8	CPL - STCMEC	216	7.4	92.3	0.3	0.0	0.0
1767	8452	LNHILL 4 138	5660	ORNGRV 8	CPL - STCMEC	216	91.8	8.2	0.0	0.0	0.0
1779	8404	SIGMOR 4 138	5688	GEOWST 8	CPL - STCMEC	215	99.2	0.8	0.0	0.0	0.0
1788	8212	DILYSW 4 138	5704	SMIGL 8	CPL - STCMEC	216	0.6	99.5	0.0	0.0	0.0
1842	8225	MOORE138 138	5895	PRSAL138	CPL - STCMEC	127	45.7	54.3	0.0	0.0	0.0
1843	8229	BATSVL 4 138	5895	PRSAL138	CPL - STCMEC	216	62.8	37.2	0.0	0.0	0.0
1730	8129	BC-STEC4 138	5562	BACT 8	CPL - STCMEC	216	100.0	0.0	0.0	0.0	0.0
1833	8212	DILYSW 4 138	5861	DILLEY 8	CPL - STCMEC	150	100.0	0.0	0.0	0.0	0.0
1811	8225	MOORE138 138	5819	HONDOCR8	CPL - STCMEC	127	99.2	0.8	0.0	0.0	0.0
1791	8404	SIGMOR 4 138	5706	SMDB 8	CPL - STCMEC	216	81.9	18.1	0.0	0.0	0.0
1754	8497	CALAN M2 69	5626	CALALN 9	CPL - STCMEC	150	100.0	0.0	0.0	0.0	0.0
1860	8314	LAPALM 4 138	5945	LOMAALT8	CPL - COB	216	100.0	0.0	0.0	0.0	0.0
1852	8339	MIL.HWY4 138	5931	MILHWY 9	CPL - COB	100	0.0	100.0	0.0	0.0	0.0
1848	9073	HOLMAN 345	5915	SO TEX 5 345	COA - STP	1075	42.4	56.3	1.3	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1787	5704	SMIGL 8	5902	MIGUEL 8	STCMEC -MIGU	215	0.0	96.1	3.8	0.0	0.0
319	1010	PERBASIN 138	1019	MOSS 138	TUEC - TUEC	143	88.1	11.9	0.0	0.0	0.0
330	1015	PERBASIN 69	1204	EXCORD T 69	TUEC - TUEC	36	90.0	10.0	0.0	0.0	0.0
348	1027	OD EHV 138	1052	REXALL 138	TUEC - TUEC	105	18.5	56.9	22.5	2.1	0.0
353	1027	OD EHV 138	1137	TI T 138	TUEC - TUEC	96	81.4	18.4	0.1	0.0	0.0
372	1053	GEN RUBR 138	1099	SWPORT T 138	TUEC - TUEC	105	69.2	29.8	1.0	0.0	0.0
405	1123	ODESSA N 69	1122	ODESSA N 138	TUEC - TUEC	75	0.0	58.9	40.7	0.4	0.0
439	1305	SNYDER 138	1318	CHINAGRV 138	TUEC - TUEC	96	0.1	81.0	18.9	0.0	0.0
362	1318	CHINAGRV 138	1032	MRGN CRK 138	TUEC - TUEC	143	64.0	36.0	0.0	0.0	0.0
456	1339	ESKOTA 138	1340	ESKOTA 69	TUEC - TUEC	56	12.4	87.5	0.0	0.0	0.0
498	1431	GRAHAM P 138	1601	GRAHAM E 138	TUEC - TUEC	96	73.1	26.7	0.2	0.0	0.0
513	1447	LK WFALL 69	1527	HOLLIDAY 69	TUEC - TUEC	42	0.0	87.6	12.4	0.0	0.0
514	1448	WFALLS 138	1449	WFALLS 69	TUEC - TUEC	100	15.4	84.6	0.0	0.0	0.0
519	1450	PLEASVAL 138	1451	PLEASVAL 69	TUEC - TUEC	100	4.8	92.6	2.6	0.0	0.0
523	1451	PLEASVAL 69	1518	IOWAPARK 69	TUEC - TUEC	62	5.9	87.3	6.8	0.0	0.0
115	1576	MINWL S 138	331	MILLER 8	TUEC - TUEC	215	0.0	0.0	100.0	0.0	0.0
558	1596	GRAHAMSS 138	1597	GRAHAMSS 69	TUEC - TUEC	60	12.6	84.5	2.8	0.0	0.0
560	1597	GRAHAMSS 69	1602	GRAHAM 69	TUEC - TUEC	48	5.1	87.1	7.8	0.0	0.0
593	1691	VALLEY 138	1758	PAYNE 138	TUEC - TUEC	251	18.5	78.2	3.3	0.0	0.0
601	1695	MOSES 345	1795	MOSES 138	TUEC - TUEC	150	0.2	83.6	16.3	0.0	0.0
615	1759	PAYNE 69	1758	PAYNE 138	TUEC - TUEC	60	24.3	75.1	0.6	0.0	0.0
620	1760	BONHM SS 138	1761	BONHM SS 69	TUEC - TUEC	50	27.8	70.0	2.2	0.0	0.0
646	1873	BENBRK 345	1874	BENBRK A 138	TUEC - TUEC	500	9.0	78.4	12.6	0.0	0.0
647	1873	BENBRK 345	1875	BENBRK B 138	TUEC - TUEC	500	9.5	76.8	13.7	0.0	0.0
653	1875	BENBRK B 138	1955	CALMONT 138	TUEC - TUEC	210	0.1	49.5	47.3	3.2	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
678	1891	DECORDVA 138	2281	GODLEY 138	TUEC - TUEC	214	41.4	58.6	0.0	0.0	0.0
685	1907	VENUS N 345	1908	VENUS 138	TUEC - TUEC	450	1.4	85.3	13.2	0.0	0.0
706	1921	LIGGETT 345	1922	LIGGETT 138	TUEC - TUEC	450	0.2	42.6	54.1	3.2	0.0
745	1967	FST HILL 138	1968	FST HILL 69	TUEC - TUEC	100	1.9	82.8	15.2	0.0	0.0
804	2279	CLEB SS 138	2281	GODLEY 138	TUEC - TUEC	214	51.6	48.4	0.0	0.0	0.0
811	2318	STERRET 69	2317	STERRET 138	TUEC - TUEC	50	60.3	39.7	0.0	0.0	0.0
834	2380	CLT NW 138	2385	N LAKE 138	TUEC - TUEC	224	96.2	3.7	0.1	0.0	0.0
850	2398	W LEVEE 345	2399	W LEVEE 138	TUEC - TUEC	600	0.3	60.2	39.6	0.0	0.0
851	2398	W LEVEE 345	2399	W LEVEE 138	TUEC - TUEC	600	0.3	60.2	39.6	0.0	0.0
866	2407	NORWDDPL 138	2487	DEN DR E 138	TUEC - TUEC	186	0.4	43.9	47.6	8.1	0.0
879	2420	C HILL 345	2421	C HILL 138	TUEC - TUEC	450	0.3	55.5	44.3	0.0	0.0
885	2428	WATMILL 345	2429	WATMILL 138	TUEC - TUEC	450	0.2	43.7	55.3	0.8	0.0
904	2437	FORNEY 345	2453	CNVIL 345	TUEC - TUEC	526	0.0	27.8	70.8	1.4	0.0
934	2461	ROYSE 345	2462	ROYSE 138	TUEC - TUEC	450	0.3	89.1	10.6	0.0	0.0
949	2470	RENERTPL 138	2468	RENER 345	TUEC - TUEC	450	0.0	75.0	25.0	0.0	0.0
958	2482	E LEVEE 138	2882	GRNVL W 138	TUEC - TUEC	186	3.7	45.9	50.4	0.0	0.0
965	2487	DEN DR E 138	2489	DEN DR 1 69	TUEC - TUEC	83	12.0	86.6	1.3	0.0	0.0
959	2883	GRNVL E 138	2482	E LEVEE 138	TUEC - TUEC	186	2.3	40.8	44.3	12.6	0.0
1085	3155	DIBOL 138	3331	DIBOL WT 138	TUEC - TUEC	84	19.4	80.6	0.0	0.0	0.0
1093	3252	JACKSWES 69	3253	JACKSNVL 138	TUEC - TUEC	75	18.8	81.2	0.0	0.0	0.0
1119	3392	JEWETT 138	3503	FAIRFLDW 138	TUEC - TUEC	72	0.6	96.3	3.1	0.0	0.0
1163	3430	SANDOW 138	3659	THORNDAL 138	TUEC - TUEC	191	17.3	57.3	25.4	0.0	0.0
1197	3643	TEMP SS 69	3644	TEMP 69	TUEC - TUEC	48	3.7	95.7	0.6	0.0	0.0
1219	4001	ADICKS 8 138	4002	ADICKS 5 345	HLP - HLP	600	99.4	0.6	0.0	0.0	0.0
1233	4016	ALTA L98 138	4546	P H R S8 138	HLP - HLP	168	4.4	95.1	0.5	0.0	0.0

(continued)

TABLE 4.2-15 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Diverging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1266	4043	BAYOU 8 138	4082	BURDET 8 138	HLP - HLP	337	26.0	73.9	0.0	0.0	0.0
1279	4050	BELAIRW8 138	4051	BELAIR 5 345	HLP - HLP	600	75.6	24.4	0.0	0.0	0.0
1282	4050	BELAIRW8 138	4556	SANFLP 8 138	HLP - HLP	337	54.4	45.6	0.0	0.0	0.0
1331	4112	CEDARP 5 345	4383	KING 5 345	HLP - HLP	872	4.2	22.0	44.5	29.4	0.0
1344	4134	H O C B9 69	4372	KARSTN 9 69	HLP - HLP	31	36.0	46.1	17.9	0.0	0.0
1347	4135	H O C 8 138	4462	NATCYL 8 138	HLP - HLP	337	35.8	46.7	17.5	0.0	0.0
1350	4135	H O C 8 138	4515	POLK 8 138	HLP - HLP	251	39.2	47.2	13.6	0.0	0.0
1376	4192	DOW345 5 345	4714	VLASCO 8 138	HLP - HLP	600	58.5	41.5	0.0	0.0	0.0
1390	4219	ELDORA 8 138	4431	MARYCK 8 138	HLP - HLP	337	0.1	62.4	37.4	0.0	0.0
1398	4235	FAIRBK 8 138	4736	T H W W8 138	HLP - HLP	313	42.4	57.6	0.0	0.0	0.0
1414	4249	FTBEND 8 138	4487	W A P 8 138	HLP - HLP	337	5.1	44.8	38.1	12.0	0.0
1491	4462	NATCYL 8 138	4487	W A P 8 138	HLP - HLP	340	28.4	51.0	20.6	0.0	0.0
1522	4515	POLK 8 138	4700	UNIVER 8 138	HLP - HLP	251	16.1	61.1	22.8	0.0	0.0
1517	4546	P H R S8 138	4509	PILGRM 8 138	HLP - HLP	340	6.1	86.3	7.6	0.0	0.0
1539	4547	P H R N8 138	4617	S HOUS98 138	HLP - HLP	337	15.6	84.4	0.0	0.0	0.0
1505	4660	TEXINS 8 138	4487	W A P 8 138	HLP - HLP	313	15.1	46.4	36.8	1.7	0.0

TABLE 4.2-16

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

	Loadflow Data					Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
7	29	BONVIL 9	39	HEARNE 9	TMPP - TMPP	31	28.7	69.7	1.6	0.0	0.0
13	33	WTSN C 8	3392	JEWETT 138	TMPP - TMPP	81	54.9	38.0	7.1	0.0	0.0
14	39	HEARNE 9	35	HEARNE 8	TMPP - TMPP	40	0.0	0.0	91.6	8.4	0.0
17	65	SILCTY 9	39	HEARNE 9	TMPP - TMPP	36	3.5	85.2	11.4	0.0	0.0
48	126	POAGE 9	134	SEATON 9	TMPP - TMPP	35	0.0	41.4	58.5	0.1	0.0
155	523	DICY S 9	545	RENO 9	TMPP - TMPP	31	0.0	14.2	85.8	0.0	0.0
243	816	OLINGR D	818	OLINGR C	TMPP - TMPP	100	0.0	0.0	100.0	0.0	0.0
242	826	CASTLE D	814	NEWMAN D	TMPP - TMPP	60	0.0	0.0	100.0	0.0	0.0
320	1010	PERBASIN 138	1019	MOSS 138	TUEC - TUEC	143	57.2	38.3	3.7	0.8	0.0
324	1010	PERBASIN 138	1103	SANDHL T 138	TUEC - TUEC	143	60.7	36.6	2.6	0.1	0.0
326	1010	PERBASIN 138	1141	HOLT SS 138	TUEC - TUEC	143	52.4	43.8	3.8	0.0	0.0
341	1023	MID EAST 138	1116	WINDWOOD 138	TUEC - TUEC	96	0.0	52.3	45.4	2.3	0.0
351	1027	OD EHV 138	1121	GLENHAVN 138	TUEC - TUEC	143	21.7	68.9	9.4	0.0	0.0
360	1032	MRGN CRK 138	1033	MRGN CRK 69	TUEC - TUEC	60	62.9	36.3	0.9	0.0	0.0
362	1032	MRGN CRK 138	1318	CHINAGRV 138	TUEC - TUEC	143	61.7	38.0	0.2	0.0	0.0
363	1032	MRGN CRK 138	1318	CHINAGRV 138	TUEC - TUEC	143	61.0	38.7	0.3	0.0	0.0
384	1074	WINK SS 138	1159	N ANDREW 138	TUEC - TUEC	96	50.5	45.7	3.8	0.0	0.0
385	1075	WINK SS 69	1254	ODBAS SS 69	TUEC - TUEC	24	63.6	35.1	1.3	0.0	0.0
405	1122	ODESSA N 138	1123	ODESSA N 69	TUEC - TUEC	75	0.1	69.5	30.1	0.3	0.0
433	1210	MIDKIFF 138	1211	MIDKIFF 69	TUEC - TUEC	45	10.9	89.1	0.1	0.0	0.0
438	1305	SNYDER 138	1306	SNYDER 69	TUEC - TUEC	50	0.4	94.8	4.8	0.0	0.0
451	1322	BIG SPG 138	1332	COSDEN 138	TUEC - TUEC	155	75.8	9.1	15.1	0.0	0.0
357	1430	GRAHAM P 345	1030	MRGN CRK 345	TUEC - TUEC	717	91.6	8.4	0.0	0.0	0.0
358	1430	GRAHAM P 345	1030	MRGN CRK 345	TUEC - TUEC	526	71.8	28.2	0.0	0.0	0.0
494	1430	GRAHAM P 345	1436	PARKER 345	TUEC - TUEC	717	69.3	30.7	0.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
495	1430	GRAHAM P 345	1436	PARKER 345	TUEC - TUEC	717	69.3	30.7	0.0	0.0	0.0
503	1436	PARKER 345	1900	COM PEAK 345	TUEC - TUEC	717	22.8	17.4	57.9	2.0	0.0
551	1576	MINWL S 138	1571	ORAN 138	TUEC - TUEC	124	0.0	17.8	82.2	0.0	0.0
573	1636	DUBLIN 138	1637	DUBLIN 69	TUEC - TUEC	25	8.4	47.3	44.3	0.0	0.0
577	1640	LNGLVL M 138	1641	STPHVIL 138	TUEC - TUEC	84	15.3	37.0	47.7	0.0	0.0
568	1640	LNGLVL M 138	1624	LEON 138	TUEC - TUEC	84	20.3	45.2	34.4	0.0	0.0
592	1691	VALLEY 138	1758	PAYNE 138	TUEC - TUEC	214	2.5	72.2	25.2	0.0	0.0
642	1860	EAGLE MT 138	1957	SAGINAW 138	TUEC - TUEC	143	57.5	42.5	0.0	0.0	0.0
643	1860	EAGLE MT 138	1957	SAGINAW 138	TUEC - TUEC	105	6.7	59.7	32.6	1.0	0.0
649	1873	BENBRK 345	1890	DECORDVA 345	TUEC - TUEC	717	9.0	55.9	34.8	0.3	0.0
651	1874	BENBRK A 138	1955	CALMONT 138	TUEC - TUEC	210	0.0	35.9	54.3	9.7	0.0
654	1875	BENBRK B 138	2164	HEMPHILL 138	TUEC - TUEC	143	0.9	42.2	50.3	6.6	0.0
834	2385	N LAKE 138	2380	CLT NW 138	TUEC - TUEC	224	83.6	14.1	2.2	0.0	0.0
835	2385	N LAKE 138	2380	CLT NW 138	TUEC - TUEC	214	83.1	11.0	5.9	0.0	0.0
861	2406	NORWD 345	2407	NORWDDPL 138	TUEC - TUEC	450	0.2	54.5	45.3	0.0	0.0
934	2461	ROYSE 345	2462	ROYSE 138	TUEC - TUEC	450	0.6	90.4	9.1	0.0	0.0
943	2466	ALLEN SS 345	2467	ALLEN SS 138	TUEC - TUEC	450	0.0	79.1	20.9	0.0	0.0
949	2468	RENER 345	2470	RENERTPL 138	TUEC - TUEC	450	0.0	78.8	21.2	0.0	0.0
1004	2756	MSQT E 138	2754	MSQT W 138	TUEC - TUEC	326	7.0	93.0	0.0	0.0	0.0
1053	3118	LUFKINSS 138	3340	LUFKIN 138	TUEC - TUEC	48	21.9	33.4	28.3	16.3	0.0
1062	3125	TDAD TR	3126	TDAD 6 G	TUEC - TUEC	265	87.5	0.1	2.9	9.4	0.0
1063	3125	TDAD TR	3127	TRINIDAD 138	TUEC - TUEC	265	0.2	69.5	22.6	7.7	0.0
1104	3354	CROCKETT 138	3392	JEWETT 138	TUEC - TUEC	84	42.8	46.7	10.4	0.0	0.0
1107	3380	BIGBRN 345	3390	JEWETT S 345	TUEC - TUEC	956	81.4	18.6	0.0	0.0	0.0
1108	3380	BIGBRN 345	3391	JEWETT N 345	TUEC - TUEC	956	71.6	27.4	1.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
	From Bus		To Bus								
Line No.	No.	Name	No.	Name	Company	Rating (MW)	Under 20%	50%	80%	100%	Over 100%
1142	3410	LAKE CRK 138	3436	WACO W 138	TUEC - TUEC	210	4.2	87.0	8.8	0.0	0.0
1143	3410	LAKE CRK 138	3438	WACO E 138	TUEC - TUEC	210	2.9	85.5	11.6	0.0	0.0
1140	3414	TEMP SS 345	3409	LAKE CRK 345	TUEC - TUEC	956	96.6	3.4	0.0	0.0	0.0
1131	3414	TEMP SS 345	3405	T HOUSE 345	TUEC - TUEC	956	98.0	2.0	0.0	0.0	0.0
1158	3429	SANDOW 345	3430	SANDOW 138	TUEC - TUEC	450	21.6	37.4	41.0	0.0	0.0
1162	3430	SANDOW 138	3650	ELGIN SS 138	TUEC - TUEC	84	15.2	16.3	43.7	24.8	0.0
1192	3627	KILLFH T 138	3629	KILL FHW 138	TUEC - TUEC	124	31.4	66.4	2.1	0.0	0.0
1209	3669	RNDRK WH 138	3668	RNDRK 138	TUEC - TUEC	124	81.0	18.6	0.3	0.0	0.0
1217	3683	MINERVA 138	3684	MINERVA 69	TUEC - TUEC	30	0.1	21.3	70.3	8.2	0.0
1230	4009	ALIEF 8 138	4487	W A P 8 138	HLP - HLP	337	29.4	65.3	5.3	0.0	0.0
1258	4039	BAMMEL 8 138	4467	N BELT 8 138	HLP - HLP	337	100.0	0.0	0.0	0.0	0.0
1303	4067	BADSCH 8 138	4714	VLASCO 8 138	HLP - HLP	168	2.8	81.5	15.8	0.0	0.0
1331	4112	CEDARP 5 345	4383	KING 5 345	HLP - HLP	872	15.9	51.7	32.1	0.3	0.0
1341	4133	H O C A9 69	4135	H O C 8 138	HLP - HLP	128	23.5	76.1	0.4	0.0	0.0
1391	4219	ELDORA 8 138	4546	P H R S8 138	HLP - HLP	337	0.0	74.1	25.9	0.0	0.0
1466	4323	HUMBLE 8 138	4685	TRSWIG 8 138	HLP - HLP	168	61.4	38.6	0.0	0.0	0.0
1492	4463	NATCYL 8 138	4487	W A P 8 138	HLP - HLP	337	35.0	60.8	4.3	0.0	0.0
1516	4675	TOMBAL 8 138	4507	PINHUR 8 138	HLP - HLP	337	100.0	0.0	0.0	0.0	0.0
1558	4675	TOMBAL 8 138	4676	TOMBAL 5 345	HLP - HLP	600	79.5	20.5	0.0	0.0	0.0
1551	4684	TEXGLF 8 138	4620	S LANE 8 138	HLP - HLP	168	68.1	31.7	0.2	0.0	0.0
1574	4740	WHITOKE8 138	4741	WHITOK 9 69	HLP - HLP	100	22.7	76.9	0.4	0.0	0.0
1656	5211	HILL CTY 345	5915	SO TEX 5 345	CPSB - CPSB	1076	67.8	32.2	0.0	0.0	0.0
1660	5225	HONDO 138	5819	HONDOCR8	CPSB - CPSB	81	37.9	55.1	6.8	0.1	0.0
1690	5371	SKYLINE 345	5370	SKYLINE 138	CPSB - CPSB	480	85.9	14.1	0.0	0.0	0.0
1691	5371	SKYLINE 345	5370	SKYLINE 138	CPSB - CPSB	480	85.9	14.1	0.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1692	5435	TUTTLE 138	5370	SKYLINE 138	CPSB - CPSB	478	86.4	12.3	1.2	0.0	0.0
1957	6232	ABMULCK4 138	6235	ABMULCK7 345	WTU - WTU	250	81.4	18.6	0.0	0.0	0.0
2108	7000	FERGSNGN	7126	FERGUSN8 138	LCRA - LCRA	480	77.3	7.6	4.2	10.9	0.0
2111	7006	GID GEN3	7310	GIDEON 8 138	LCRA - LCRA	380	34.5	6.4	26.9	32.3	0.0
2112	7010	FPP GEN1	7056	FPP 5 345	LCRA - LCRA	600	16.1	7.1	11.7	65.1	0.0
2114	7012	FPP GEN3	7056	FPP 5 345	LCRA - LCRA	2114	16.4	9.2	23.9	50.5	0.0
2129	7040	AUSTROP5 345	7328	AUSTROP8 138	LCRA - LCRA	2129	24.0	75.5	0.5	0.0	0.0
2127	7042	ZORN 5 345	7040	AUSTROP5 345	LCRA - LCRA	2127	98.3	1.6	0.0	0.0	0.0
2144	7064	LAMPSAS8 138	7061	COPP CV8 138	LCRA - LCRA	2144	87.8	12.2	0.0	0.0	0.0
2145	7064	LAMPSAS8 138	7070	GOLDTWT8 138	LCRA - LCRA	2145	54.9	37.1	6.5	1.4	0.1
2166	7107	WIRTZ 9 69	7110	WIRTNUT1	LCRA - LCRA	2166	48.6	35.3	15.3	0.7	0.0
2170	7119	PITSBRG9 69	7114	CASTELL9 69	LCRA - LCRA	2170	72.2	24.6	3.2	0.0	0.0
2203	7178	MARION 8 138	7176	COMAL 8 138	LCRA - LCRA	2203	1.8	67.9	30.3	0.0	0.0
2204	7178	MARION 8 138	7176	COMAL 8 138	LCRA - LCRA	64	0.1	21.6	51.8	26.5	0.0
2215	7192	SANMRCS8 138	7200	CANYON 8 138	LCRA - LCRA	101	2.9	55.0	40.6	1.5	0.0
2221	7200	CANYON 8 138	7498	BUDA 8 138	LCRA - LCRA	101	29.1	60.9	10.0	0.0	0.0
2224	7202	HICROSS8 138	7498	BUDA 8 138	LCRA - LCRA	101	93.8	6.2	0.0	0.0	0.0
2255	7264	PETERS 8 138	7270	BELVILE8 138	LCRA - LCRA	171	80.5	19.5	0.0	0.0	0.0
2258	7286	FAYET 8 138	7270	BELVILE8 138	LCRA - LCRA	171	78.1	21.9	0.0	0.0	0.0
2284	7310	GIDEON 8 138	7328	AUSTROP8 138	LCRA - LCRA	171	11.4	36.2	31.2	21.2	0.0
2285	7310	GIDEON 8 138	7328	AUSTROP8 138	LCRA - LCRA	171	16.8	41.3	41.9	0.0	0.0
2299	7350	MORMON 8 138	7352	LAGOVST8 138	LCRA - LCRA	171	87.0	13.0	0.0	0.0	0.0
2355	8121	BLESSNG4 138	8127	L.CITYM4 138	CPL - CPL	161	47.0	52.1	0.9	0.0	0.0
2353	8123	BLESSNG6 345	8121	BLESSNG4 138	CPL - CPL	600	34.7	63.1	2.2	0.0	0.0
2354	8125	LOLITA 4 138	8121	BLESSNG4 138	CPL - CPL	216	67.7	29.5	2.8	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
2375	8152	CARB-SD4 138	8144	AIRCO 4 138	CPL - CPL	161	27.4	69.9	2.8	0.0	0.0
2387	8162	COLETO 4 138	8186	KENDYSW4 138	CPL - CPL	216	41.3	56.0	2.6	0.0	0.0
2399	8172	VICTRA 4 138	8183	THOMSTN4 138	CPL - CPL	216	48.0	38.2	13.8	0.1	0.0
2400	8172	VICTRA 4 138	8452	LNHILL 4 138	CPL - CPL	127	59.9	40.1	0.0	0.0	0.0
2405	8183	THOMSTN4 138	8192	C.LCRA 4 138	CPL - CPL	216	49.6	37.5	12.8	0.1	0.0
2407	8184	KENDYSW2 69	8188	KENEDY 2 69	CPL - CPL	41	5.9	79.9	14.0	0.3	0.0
2428	8214	ARTESIA2 69	8280	ASHERTN2 69	CPL - CPL	41	97.6	2.4	0.0	0.0	0.0
2440	8234	UVALDE 4 138	8246	ASPHALT4 138	CPL - CPL	82	47.0	49.1	3.8	0.0	0.0
2445	8246	ASPHALT4 138	8252	BRACKVL4 138	CPL - CPL	82	50.5	46.6	2.9	0.0	0.0
2455	8274	CNC.W T4 138	8283	ASHERTN4 138	CPL - CPL	82	46.8	50.7	2.5	0.0	0.0
2457	8283	ASHERTN4 138	8293	LAREDO 4 138	CPL - CPL	127	60.0	37.7	2.3	0.0	0.0
2464	8293	LAREDO 4 138	8297	BRUNI 4 138	CPL - CPL	82	58.6	41.4	0.0	0.0	0.0
2466	8297	BRUNI 4 138	8510	FALF 4 138	CPL - CPL	82	32.6	67.3	0.0	0.0	0.0
2468	8300	RAYVILE2 69	8302	RAYVILE4 138	CPL - CPL	37	0.0	57.1	41.4	1.5	0.0
2475	8310	LAPALM 2 69	8314	LAPALM 4 138	CPL - CPL	93	0.1	89.3	10.6	0.0	0.0
2476	8310	LAPALM 2 69	8314	LAPALM 4 138	CPL - CPL	93	0.0	84.3	15.7	0.0	0.0
2534	8392	BATES 4 138	8399	GARZA 4 138	CPL - CPL	82	95.7	4.3	0.0	0.0	0.0
2467	8395	FALCON 4 138	8299	ZAPATA 4 138	CPL - CPL	82	93.4	6.6	0.0	0.0	0.0
2535	8395	FALCON 4 138	8399	GARZA 4 138	CPL - CPL	82	100.0	0.0	0.0	0.0	0.0
2537	8403	T.RIVR 4 138	8400	T.RIVR 2 69	CPL - CPL	37	20.8	79.1	0.1	0.0	0.0
2631	8500	ALICE 2 69	8505	FREER 2 69	CPL - CPL	41	12.0	84.3	3.8	0.0	0.0
2568	8439	N BAY 2 69	8468	HIWAY9 2 69	CPL - CPL	58	39.3	35.6	25.1	0.0	0.0
2569	8439	N BAY 2 69	8871	AVRYP1-2 69	CPL - CPL	71	48.0	52.0	0.0	0.0	0.0
2657	9073	HOLMAN 345	9074	LYTTON 345	COA - COA	1075	6.6	75.4	18.0	0.0	0.0
2682	9124	KINGSBRY 138	9125	KINGSBRY 69	COA - COA	220	83.1	16.9	0.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
2686	9124	KINGSBRY 138	9291	WHELESS 138	COA - COA	350	99.4	0.6	0.0	0.0	0.0
2689	9128	NORTHLND 138	9129	NORTHLND 69	COA - COA	220	20.0	76.0	3.9	0.0	0.0
2697	9132	SEAHOLM 138	9287	WARREN 138	COA - COA	215	100.0	0.0	0.0	0.0	0.0
2678	9147	HICROSS 138	9120	BURLESON 138	COA - COA	215	31.4	67.0	1.6	0.0	0.0
2718	9187	DECKER 138	9271	SPRINKLE 138	COA - COA	430	99.3	0.7	0.0	0.0	0.0
2666	9271	SPRINKLE 138	9079	MCNEIL 138	COA - COA	430	100.0	0.0	0.0	0.0	0.0
1112	3390	JEWETT S 345	4401	LIMEST 5 345	TUEC - HLP	1300	59.5	40.5	0.0	0.0	0.0
1113	3390	JEWETT S 345	4737	T H W 5 345	TUEC - HLP	762	83.3	16.7	0.0	0.0	0.0
1116	3391	JEWETT N 345	4401	LIMEST 5 345	TUEC - HLP	1300	100.0	0.0	0.0	0.0	0.0
1117	3391	JEWETT N 345	4676	TOMBAL 5 345	TUEC - HLP	850	95.0	5.0	0.0	0.0	0.0
1124	3400	TWIN OAK 345	4401	LIMEST 5 345	TUEC - HLP	1300	82.9	17.1	0.0	0.0	0.0
1125	3400	TWIN OAK 345	4401	LIMEST 5 345	TUEC - HLP	1300	82.9	17.1	0.0	0.0	0.0
1126	3400	TWIN OAK 345	4562	SALHLP 5 345	TUEC - HLP	1300	98.0	2.0	0.0	0.0	0.0
1127	3400	TWIN OAK 345	4737	T H W 5 345	TUEC - HLP	850	99.7	0.3	0.0	0.0	0.0
1109	3386	NAVAR SS 345	4401	LIMEST 5 345	TUEC - HLP	1650	41.1	58.9	0.0	0.0	0.0
1110	3386	NAVAR SS 345	4401	LIMEST 5 345	TUEC - HLP	1650	41.1	58.9	0.0	0.0	0.0
1061	3124	TRINDAD2 345	4428	MALKOF 5 345	TUEC - HLP	1650	100.0	0.0	0.0	0.0	0.0
1075	3130	FOR GROV 345	4428	MALKOF 5 345	TUEC - HLP	1650	100.0	0.0	0.0	0.0	0.0
327	1010	PERBASIN 138	6655	BARRILA4 138	TUEC - WTU	158	86.1	13.9	0.0	0.0	0.0
457	1339	ESKOTA 138	6260	ABSOUTH4 138	TUEC - WTU	65	40.2	49.9	9.2	0.6	0.0
462	1340	ESKOTA 69	6247	TRENT 2 69	TUEC - WTU	33	90.0	10.0	0.0	0.0	0.0
475	1398	RADIUM M 138	6180	RADIUM 2 69	TUEC - WTU	63	79.1	20.9	0.0	0.0	0.0
487	1425	FISHRDSS 345	6100	OKLAEHV7 345	TUEC - WTU	1072	59.1	39.9	1.0	0.0	0.0
542	1538	ELECTRA 69	6075	WAGONER2 69	TUEC - WTU	33	67.7	32.3	0.0	0.0	0.0
569	1624	LEON 138	6310	PUTTAP 4 138	TUEC - WTU	84	52.1	47.4	0.4	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
571	1625	LEON 2 69	6311	CISCO 2 69	TUEC - WTU	33	66.0	34.0	0.0	0.0	0.0
540	1533	BOMARTON 69	6107	MUNDAY 2 69	TUEC - WTU	42	97.1	2.9	0.0	0.0	0.0
467	1371	MURRAY M 138	6161	PTCREEK4 138	TUEC - WTU	155	92.3	7.7	0.0	0.0	0.0
474	1398	RADIUM M 138	6161	PTCREEK4 138	TUEC - WTU	149	94.5	5.4	0.0	0.0	0.0
359	1030	MRGN CRK 345	6235	ABMULCK7 345	TUEC - WTU	1072	94.8	5.2	0.0	0.0	0.0
496	1430	GRAHAM P 345	6235	ABMULCK7 345	TUEC - WTU	1072	100.0	0.0	0.0	0.0	0.0
463	1352	CHALK 69	6436	STRLGCO2 69	TUEC - WTU	33	86.5	13.3	0.2	0.0	0.0
1159	3429	SANDOW 345	7040	AUSTROP5 345	TUEC - LCRA	956	96.9	3.1	0.0	0.0	0.0
1160	3429	SANDOW 345	7040	AUSTROP5 345	TUEC - LCRA	1072	98.7	1.3	0.0	0.0	0.0
1207	3665	PFLGRVIL 138	7332	ELGIN 8 138	TUEC - LCRA	214	29.3	70.7	0.0	0.0	0.0
1208	3665	PFLGRVIL 138	7334	MCNEIL 8 138	TUEC - LCRA	214	45.9	54.1	0.0	0.0	0.0
1194	3630	COPPERCV 138	7061	COPP CV8 138	TUEC - LCRA	124	78.8	19.1	2.1	0.0	0.0
584	1655	BRNWD SS 138	7070	GOLDTWT8 138	TUEC - LCRA	127	88.1	11.9	0.0	0.0	0.0
1212	3672	RNDRK S 138	7334	MCNEIL 8 138	TUEC - LCRA	214	83.1	14.6	2.3	0.0	0.0
1211	3669	RNDRK WH 138	7346	GABRIEL8 138	TUEC - LCRA	214	99.1	0.9	0.0	0.0	0.0
1218	3687	JARRELL 138	7346	GABRIEL8 138	TUEC - LCRA	214	99.9	0.1	0.0	0.0	0.0
11	3682	MILANO M 138	32	RBRTSN 8	TUEC - TMPP	84	62.7	32.6	4.7	0.1	0.0
115	1576	MINWL S 138	331	MILLER 8	TUEC - TMPP	215	0.0	0.1	99.9	0.0	0.0
316	1853	ROANOKE 345	988	W.DENT B	TUEC - TMPP	1494	100.0	0.0	0.0	0.0	0.0
309	2461	ROYSE 345	970	BEN DV B	TUEC - TMPP	1016	99.7	0.3	0.0	0.0	0.0
80	3406	ELM MOTT 345	240	WHITNY 5	TUEC - TMPP	1072	100.0	0.0	0.0	0.0	0.0
604	1695	MOSES 345	5925	DC-EAST	TUEC - DCSPP	1078	100.0	0.0	0.0	0.0	0.0
1513	4494	PETERS 8 138	7264	PETERS 8 138	HLP - LCRA	340	96.2	3.8	0.0	0.0	0.0
1540	4562	SALHLP 5 345	7058	SALEM 5 345	HLP - LCRA	1000	82.7	17.3	0.0	0.0	0.0
1552	4620	S LANE 8 138	8127	L.CITYM4 138	HLP - CPL	600	100.0	0.0	0.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1377	4192	DOW345 5 345	5915	SO TEX 5 345	HLP - STP	872	60.7	38.5	0.8	0.0	0.0
1507	4488	W A P 5 345	5915	SO TEX 5 345	HLP - STP	872	43.7	50.0	6.3	0.0	0.0
304	4383	KING 5 345	967	GIBCRK B	HLP - TMPP	1300	100.0	0.0	0.0	0.0	0.0
305	4477	OBRIEN 5 345	967	GIBCRK B	HLP - TMPP	850	99.0	1.0	0.0	0.0	0.0
1657	5211	HILL CTY 345	7044	MARION 5 345	CPSB - LCRA	1076	98.4	1.6	0.0	0.0	0.0
1695	5371	SKYLINE 345	7044	MARION 5 345	CPSB - LCRA	1076	79.6	20.4	0.0	0.0	0.0
1649	5200	HELOTES 138	7151	CICO 8 138	CPSB - LCRA	215	37.9	60.2	2.0	0.0	0.0
1670	5260	LEON CR1 138	8203	PLESTN 4 138	CPSB - CPL	110	50.9	43.9	5.2	0.1	0.0
1632	5155	FLORESVI 138	8186	KENDYSW4 138	CPSB - CPL	161	86.2	13.3	0.5	0.0	0.0
1696	5371	SKYLINE 345	8455	LNHILL 6 345	CPSB - CPL	1076	99.7	0.3	0.0	0.0	0.0
1656	5211	HILL CTY 345	5915	SO TEX 5 345	CPSB - STP	1076	67.8	32.2	0.0	0.0	0.0
1694	5371	SKYLINE 345	5915	SO TEX 5 345	CPSB - STP	1076	63.3	36.7	0.0	0.0	0.0
1660	5225	HONDO 138	5819	HONDOCR8	CPSB- STCMEC	81	37.9	55.1	6.8	0.1	0.0
2012	6391	FRDONIT2 69	7114	CASTELL9 69	WTU - LCRA	44	88.0	12.0	0.0	0.0	0.0
2014	6392	FREDPHT2 69	7130	GILLSPE9 69	WTU - LCRA	33	79.3	20.7	0.0	0.0	0.0
2011	6390	MASON4 138	7132	GILLSPE8 138	WTU - LCRA	160	57.9	40.9	1.2	0.0	0.0
2060	6513	SONORA 2 69	8239	FRSRNCH2 69	WTU - CPL	41	99.0	1.0	0.0	0.0	0.0
2062	6515	SONORA 4 138	8259	CTHRNR 4 138	WTU - CPL	158	94.7	5.3	0.0	0.0	0.0
2074	6567	RGECCOM2 69	8253	HAMILTN2 69	WTU - CPL	41	86.2	13.8	0.0	0.0	0.0
1895	6100	OKLAEHV7 345	9035	VVIEWDC	WTU - COA	200	24.9	75.1	0.0	0.0	0.0
2244	7244	CUERO 8 138	8192	C.LCRA 4 138	LCRA - CPL	500	96.3	3.7	0.0	0.0	0.0
2254	7258	GLIDDEN8 138	8109	CPL-GLN4 138	LCRA - CPL	216	100.0	0.0	0.0	0.0	0.0
2131	7040	AUSTROP5 345	9078	MCNEIL 345	LCRA - COA	1195	50.3	49.7	0.0	0.0	0.0
2141	7056	FPP 5 345	9073	HOLMAN 345	LCRA - COA	1076	41.4	57.6	1.0	0.0	0.0
2225	7202	HICROSS8 138	9147	HICROSS 138	LCRA - COA	287	57.0	39.0	4.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
2288	7328	AUSTROP8 138	9154	WEBERVIL 138	LCRA - COA	430	1.6	41.4	55.9	1.1	0.0
2291	7334	MCNEIL 8 138	9079	MCNEIL 138	LCRA - COA	480	87.6	12.4	0.0	0.0	0.0
2130	7040	AUSTROP5 345	9074	LYTTON 345	LCRA - COA	1076	100.0	0.0	0.0	0.0	0.0
2136	7042	ZORN 5 345	9074	LYTTON 345	LCRA - COA	1076	97.6	2.4	0.0	0.0	0.0
2295	7338	AUSTIN 9 69	9140	AUSTNDAM 69	LCRA - COA	108	100.0	0.0	0.0	0.0	0.0
28	7044	MARION 5 345	52	SMIGL B5	LCRA - TMPP	1075	100.0	0.0	0.0	0.0	0.0
29	7044	MARION 5 345	52	SMIGL B5	LCRA - TMPP	1075	100.0	0.0	0.0	0.0	0.0
45	7345	GABRIEL9 69	123	JARREL 9	LCRA - TMPP	43	95.0	5.0	0.0	0.0	0.0
1846	8123	BLESSNG6 345	5915	SO TEX 5 345	CPL - STP	1076	80.7	19.3	0.0	0.0	0.0
1847	8455	LNHILL 6 345	5915	SO TEX 5 345	CPL - STP	1076	43.0	56.8	0.2	0.0	0.0
1707	8172	VICTRA 4 138	5502	RAYBRN 8	CPL - STCMEC	160	26.9	53.0	19.9	0.2	0.0
1724	8121	BLESSNG4 138	5546	DNVG 8	CPL - STCMEC	216	27.3	72.7	0.0	0.0	0.0
1767	8452	LNHILL 4 138	5660	ORNGRV 8	CPL - STCMEC	216	91.4	8.6	0.0	0.0	0.0
1779	8404	SIGMOR 4 138	5688	GEOWST 8	CPL - STCMEC	215	98.8	1.2	0.0	0.0	0.0
1788	8212	DILYSW 4 138	5704	SMIGL 8	CPL - STCMEC	216	8.8	91.2	0.0	0.0	0.0
1842	8225	MOORE138 138	5895	PRSAL138	CPL - STCMEC	127	94.6	5.4	0.0	0.0	0.0
1843	8229	BATSVL 4 138	5895	PRSAL138	CPL - STCMEC	216	66.1	33.9	0.0	0.0	0.0
1730	8129	BC-STEC4 138	5562	BACT 8	CPL - STCMEC	216	100.0	0.0	0.0	0.0	0.0
1833	8212	DILYSW 4 138	5861	DILLEY 8	CPL - STCMEC	150	100.0	0.0	0.0	0.0	0.0
1811	8225	MOORE138 138	5819	HONDOCR8	CPL - STCMEC	127	97.8	2.2	0.0	0.0	0.0
1791	8404	SIGMOR 4 138	5706	SMDB 8	CPL - STCMEC	216	72.8	27.1	0.0	0.0	0.0
1754	8497	CALAN M2 69	5626	CALALN 9	CPL - STCMEC	150	100.0	0.0	0.0	0.0	0.0
1860	8314	LAPALM 4 138	5945	LOMAALT8	CPL - COB	216	100.0	0.0	0.0	0.0	0.0
1852	8339	MIL.HWY4 138	5931	MILHWY 9	CPL - COB	100	0.0	100.0	0.0	0.0	0.0
1848	9073	HOLMAN 345	5915	SO TEX 5 345	COA - STP	1075	59.2	40.8	0.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1787	5704	SMIGL 8	5902	MIGUEL 8	STCMEC -MIGU	215	0.0	99.2	0.8	0.0	0.0
319	1010	PERBASIN 138	1019	MOSS 138	TUEC - TUEC	143	61.3	36.0	2.5	0.2	0.0
330	1015	PERBASIN 69	1204	EXCORD T 69	TUEC - TUEC	36	63.2	35.6	1.2	0.0	0.0
348	1027	OD EHV 138	1052	REXALL 138	TUEC - TUEC	105	44.7	41.8	11.5	2.1	0.0
353	1027	OD EHV 138	1137	TI T 138	TUEC - TUEC	96	57.1	42.0	0.9	0.0	0.0
372	1053	GEN RUBR 138	1099	SWPORT T 138	TUEC - TUEC	105	52.8	43.7	3.3	0.2	0.0
405	1123	ODESSA N 69	1122	ODESSA N 138	TUEC - TUEC	75	0.1	69.5	30.1	0.3	0.0
439	1305	SNYDER 138	1318	CHINAGRV 138	TUEC - TUEC	96	0.1	82.2	17.8	0.0	0.0
362	1318	CHINAGRV 138	1032	MRGN CRK 138	TUEC - TUEC	143	61.7	38.0	0.2	0.0	0.0
456	1339	ESKOTA 138	1340	ESKOTA 69	TUEC - TUEC	56	12.7	87.1	0.1	0.0	0.0
498	1431	GRAHAM P 138	1601	GRAHAM E 138	TUEC - TUEC	96	58.6	32.2	8.9	0.2	0.0
513	1447	LK WFALL 69	1527	HOLLIDAY 69	TUEC - TUEC	42	1.0	93.1	5.9	0.0	0.0
514	1448	WFALLS 138	1449	WFALLS 69	TUEC - TUEC	100	13.5	86.5	0.0	0.0	0.0
519	1450	PLEASVAL 138	1451	PLEASVAL 69	TUEC - TUEC	100	4.3	93.0	2.6	0.0	0.0
523	1451	PLEASVAL 69	1518	IOWAPARK 69	TUEC - TUEC	62	5.9	87.3	6.8	0.0	0.0
115	1576	MINWL S 138	331	MILLER 8	TUEC - TUEC	215	0.0	0.1	99.9	0.0	0.0
558	1596	GRAHAMSS 138	1597	GRAHAMSS 69	TUEC - TUEC	60	12.2	84.9	2.8	0.0	0.0
560	1597	GRAHAMSS 69	1602	GRAHAM 69	TUEC - TUEC	48	5.2	85.1	9.7	0.0	0.0
593	1691	VALLEY 138	1758	PAYNE 138	TUEC - TUEC	251	15.3	76.8	7.9	0.0	0.0
601	1695	MOSES 345	1795	MOSES 138	TUEC - TUEC	150	0.3	85.6	14.1	0.0	0.0
615	1759	PAYNE 69	1758	PAYNE 138	TUEC - TUEC	60	23.9	75.3	0.8	0.0	0.0
620	1760	BONHM SS 138	1761	BONHM SS 69	TUEC - TUEC	50	23.6	70.4	6.0	0.0	0.0
646	1873	BENBRK 345	1874	BENBRK A 138	TUEC - TUEC	500	4.3	80.7	15.0	0.0	0.0
647	1873	BENBRK 345	1875	BENBRK B 138	TUEC - TUEC	500	4.2	79.3	16.5	0.0	0.0
653	1875	BENBRK B 138	1955	CALMONT 138	TUEC - TUEC	210	0.0	52.4	47.1	0.6	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
678	1891	DECORDVA 138	2281	GODLEY 138	TUEC - TUEC	214	25.8	72.9	1.2	0.0	0.0
685	1907	VENUS N 345	1908	VENUS 138	TUEC - TUEC	450	1.9	92.9	5.2	0.0	0.0
706	1921	LIGGETT 345	1922	LIGGETT 138	TUEC - TUEC	450	0.2	64.6	35.2	0.0	0.0
745	1967	FST HILL 138	1968	FST HILL 69	TUEC - TUEC	100	3.4	85.8	10.7	0.0	0.0
804	2279	CLEB SS 138	2281	GODLEY 138	TUEC - TUEC	214	35.8	63.0	1.2	0.0	0.0
811	2318	STERRET 69	2317	STERRET 138	TUEC - TUEC	50	44.7	55.3	0.0	0.0	0.0
834	2380	CLT NW 138	2385	N LAKE 138	TUEC - TUEC	224	83.6	14.1	2.2	0.0	0.0
850	2398	W LEVEE 345	2399	W LEVEE 138	TUEC - TUEC	600	0.4	76.4	23.3	0.0	0.0
851	2398	W LEVEE 345	2399	W LEVEE 138	TUEC - TUEC	600	0.4	76.4	23.3	0.0	0.0
866	2407	NORWDDPL 138	2487	DEN DR E 138	TUEC - TUEC	186	2.8	51.1	44.2	1.9	0.0
879	2420	C HILL 345	2421	C HILL 138	TUEC - TUEC	450	0.4	74.9	24.7	0.0	0.0
885	2428	WATMILL 345	2429	WATMILL 138	TUEC - TUEC	450	0.2	67.0	32.7	0.0	0.0
904	2437	FORNEY 345	2453	CNVIL 345	TUEC - TUEC	526	0.0	46.3	53.4	0.3	0.0
934	2461	ROYSE 345	2462	ROYSE 138	TUEC - TUEC	450	0.6	90.4	9.1	0.0	0.0
949	2470	RENERTPL 138	2468	RENER 345	TUEC - TUEC	450	0.0	78.8	21.2	0.0	0.0
958	2482	E LEVEE 138	2882	GRNVL W 138	TUEC - TUEC	186	6.7	52.9	40.4	0.0	0.0
965	2487	DEN DR E 138	2489	DEN DR 1 69	TUEC - TUEC	83	12.0	86.6	1.3	0.0	0.0
959	2883	GRNVL E 138	2482	E LEVEE 138	TUEC - TUEC	186	4.3	49.9	41.4	4.4	0.0
1085	3155	DIBOL 138	3331	DIBOL WT 138	TUEC - TUEC	84	19.4	80.6	0.0	0.0	0.0
1093	3252	JACKSWES 69	3253	JACKSNVL 138	TUEC - TUEC	75	18.8	81.2	0.0	0.0	0.0
1119	3392	JEWETT 138	3503	FAIRFLDW 138	TUEC - TUEC	72	0.6	96.3	3.1	0.0	0.0
1163	3430	SANDOW 138	3659	THORNDAL 138	TUEC - TUEC	191	10.7	44.4	44.9	0.0	0.0
1197	3643	TEMP SS 69	3644	TEMP 69	TUEC - TUEC	48	2.9	95.8	1.3	0.0	0.0
1219	4001	ADICKS 8 138	4002	ADICKS 5 345	HLP - HLP	600	81.8	18.2	0.0	0.0	0.0
1233	4016	ALTA L98 138	4546	P H R S8 138	HLP - HLP	168	1.8	90.3	8.0	0.0	0.0

(continued)

TABLE 4.2-16 (continued)

Load Carried by Monitored Lines in 1990
Reference Case - Converging Gas Prices

Loadflow Data						Line	Line Loading				
Line	From Bus		To Bus			Rating	Under				Over
No.	No.	Name	No.	Name	Company	(MW)	20%	50%	80%	100%	100%
1266	4043	BAYOU 8 138	4082	BURDET 8 138	HLP - HLP	337	33.4	66.6	0.0	0.0	0.0
1279	4050	BELAIRW8 138	4051	BELAIR 5 345	HLP - HLP	600	50.5	49.5	0.0	0.0	0.0
1282	4050	BELAIRW8 138	4556	SANFLP 8 138	HLP - HLP	337	42.2	57.8	0.0	0.0	0.0
1331	4112	CEDARP 5 345	4383	KING 5 345	HLP - HLP	872	15.9	51.7	32.1	0.3	0.0
1344	4134	H O C B9 69	4372	KARSTN 9 69	HLP - HLP	31	48.4	51.1	0.5	0.0	0.0
1347	4135	H O C 8 138	4462	NATCYL 8 138	HLP - HLP	337	45.5	54.1	0.4	0.0	0.0
1350	4135	H O C 8 138	4515	POLK 8 138	HLP - HLP	251	28.9	65.4	5.7	0.0	0.0
1376	4192	DOW345 5 345	4714	VLASCO 8 138	HLP - HLP	600	14.3	84.4	1.3	0.0	0.0
1390	4219	ELDORA 8 138	4431	MARYCK 8 138	HLP - HLP	337	0.6	79.7	19.7	0.0	0.0
1398	4235	FAIRBK 8 138	4736	T H W W8 138	HLP - HLP	313	26.5	73.5	0.0	0.0	0.0
1414	4249	FTBEND 8 138	4487	W A P 8 138	HLP - HLP	337	29.6	68.4	1.9	0.0	0.0
1491	4462	NATCYL 8 138	4487	W A P 8 138	HLP - HLP	340	40.8	58.3	0.9	0.0	0.0
1522	4515	POLK 8 138	4700	UNIVER 8 138	HLP - HLP	251	35.8	58.9	5.3	0.0	0.0
1517	4546	P H R S8 138	4509	PILGRM 8 138	HLP - HLP	340	10.8	85.8	3.5	0.0	0.0
1539	4547	P H R N8 138	4617	S HOUS98 138	HLP - HLP	337	37.0	63.0	0.0	0.0	0.0
1505	4660	TEXINS 8 138	4487	W A P 8 138	HLP - HLP	313	37.1	60.4	2.5	0.0	0.0

because the system responds according to the laws of physics. Such a power surge would likely cause an overload on some HL&P-TUEC lines which may cause the automatic control system to cut them off from the grid. With those lines out, the power would redistribute itself over the remaining lines and, again, could cause some lines to overload and cut off. Such a cascading effect could cause parts of the ERCOT network to be blacked out -- a clearly unacceptable result. Thus, to ensure that the reliability of the system continues to meet ERCOT criteria at higher transactions levels, it seems fairly certain that more lines will have to be built or existing lines must be upgraded.

It should be noted that it is ERCOT's, as well as other power pools', obligation to provide an extremely reliable supply of electricity. Some studies suggest that the "social costs" of a blackout are very high and it is not appropriate to assign dollar values to the costs. A blackout in New York in 1977 resulted in extensive damage from vandalism and theft; so that the appropriate degree of reliability is very difficult to determine in a larger social context. Each year ERCOT performs a Transfer Limit Study to determine the capability of the transmission grid to handle emergency situations. In this study, the capability of the transmission network to handle power shipments between utilities is calculated under normal and contingency conditions. The contingency conditions are created by assuming outages of selected critical transmission lines in the system. In the next Chapter, a few scenarios are developed to test the effect of alternative outage or transmission contingency conditions with the model constraining the dispatch of available units to avoid overloads when such contingencies occur. The results of these scenarios on the level of transactions within the ERCOT network are then analyzed and discussed.

4.2.6 Marginal Costs

Figures 4.2-15 through 4.2-18 show the marginal costs of the utility systems modeled under own-load operation at different intervals for 1990 and 1995. While marginal costs are pricing signals directing the flow of power, it should be noted that the marginal costs (assuming diverging gas prices) are calculated based on "average fuel prices" and there is approximately a $10/MWH to $20/MWH difference between the high and the low. When the incremental prices, which are assumed equal for all the utilities, are used in the converging fuel price cases, the high-low range is reduced to approximately $5/MWH to 10$/MWH, and the volume of transactions and savings are reduced.

Marginal costs for each interval correspond to the costs of operating the marginal units -- the last units loaded to satisfy generation requirements. There are two groups of parameters that affect the system marginal cost: the price component of the marginal unit itself and the relationship between the load and available capacity. While the effect of the marginal unit's price component is obvious, the effect of the load and capacity relationships require some understanding about the economic dispatch process. Because the units (strictly speaking, their capacity sections) are loaded one by one until the MW demand is reached, the lower the demand, the cheaper the last unit loaded. The results show that the load-capacity relationship is a very important component in driving transactions. The high capacity reserves not only enhance the differences between system marginal costs, they also represent potentially available capacity for shipments.

4.2.7 Historical Year Test Case

As suggested by the Commissioners after review of the Interim Report, a test case for 1986 was developed. The purpose of this case is to compare the model results against actual 1986 data and provide some indication of the transactions and savings that could

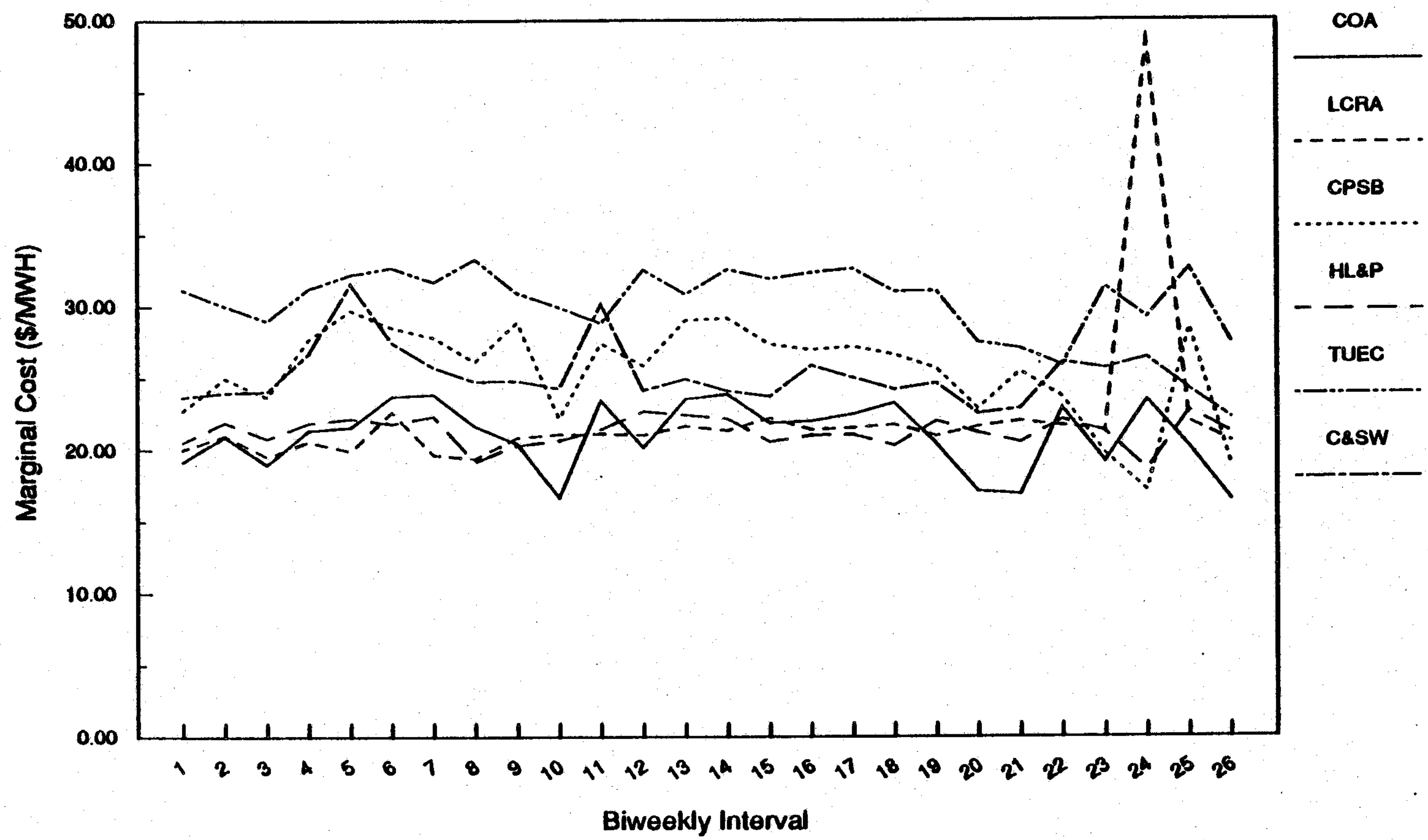


figure 4.2-15 1990 Own-Load Marginal Cost
Reference Case - Diverging Gas Prices

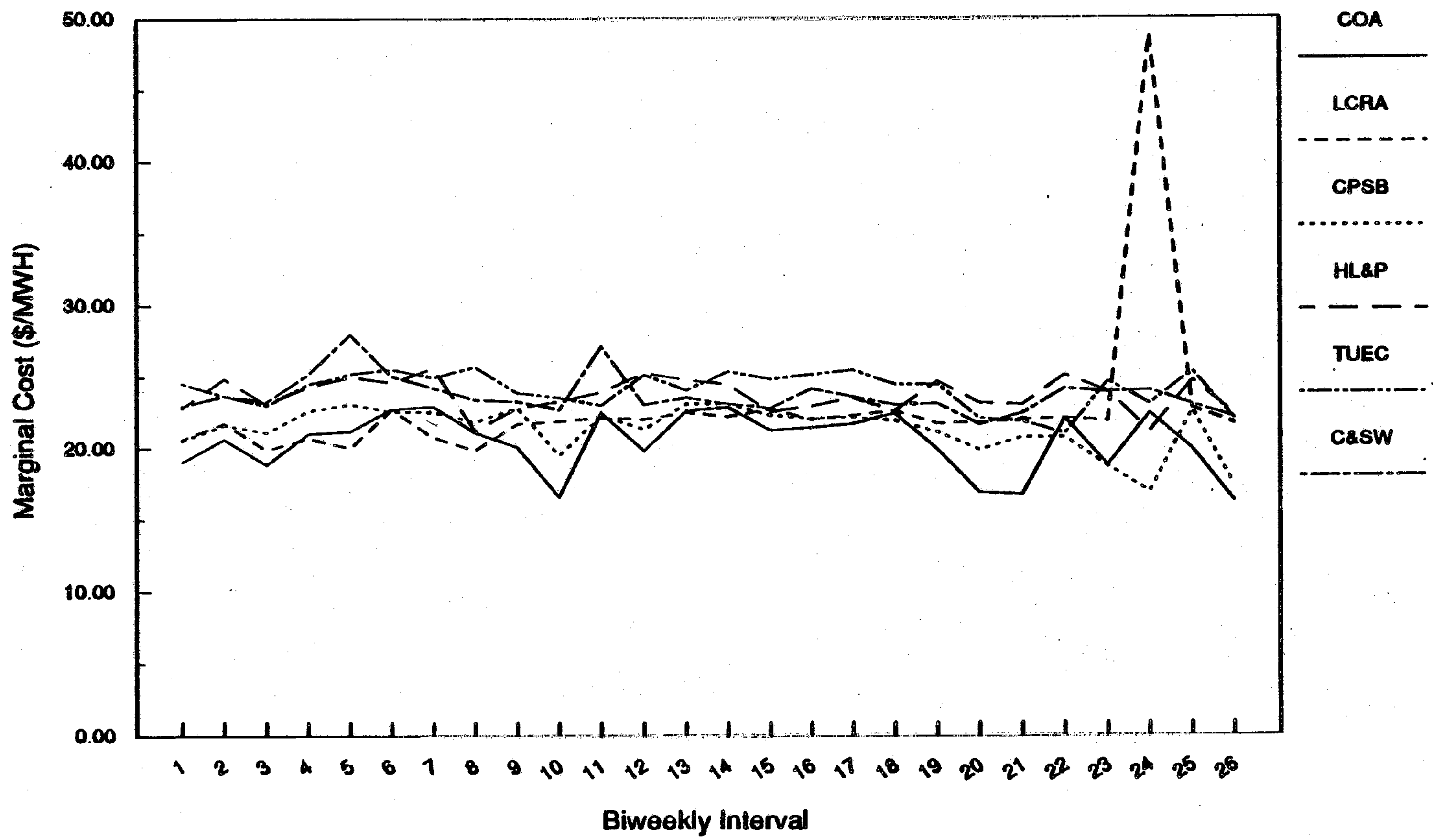


Figure 4.2-16 1990 Own-Load Marginal Cost
Reference Case - Converging Gas Prices

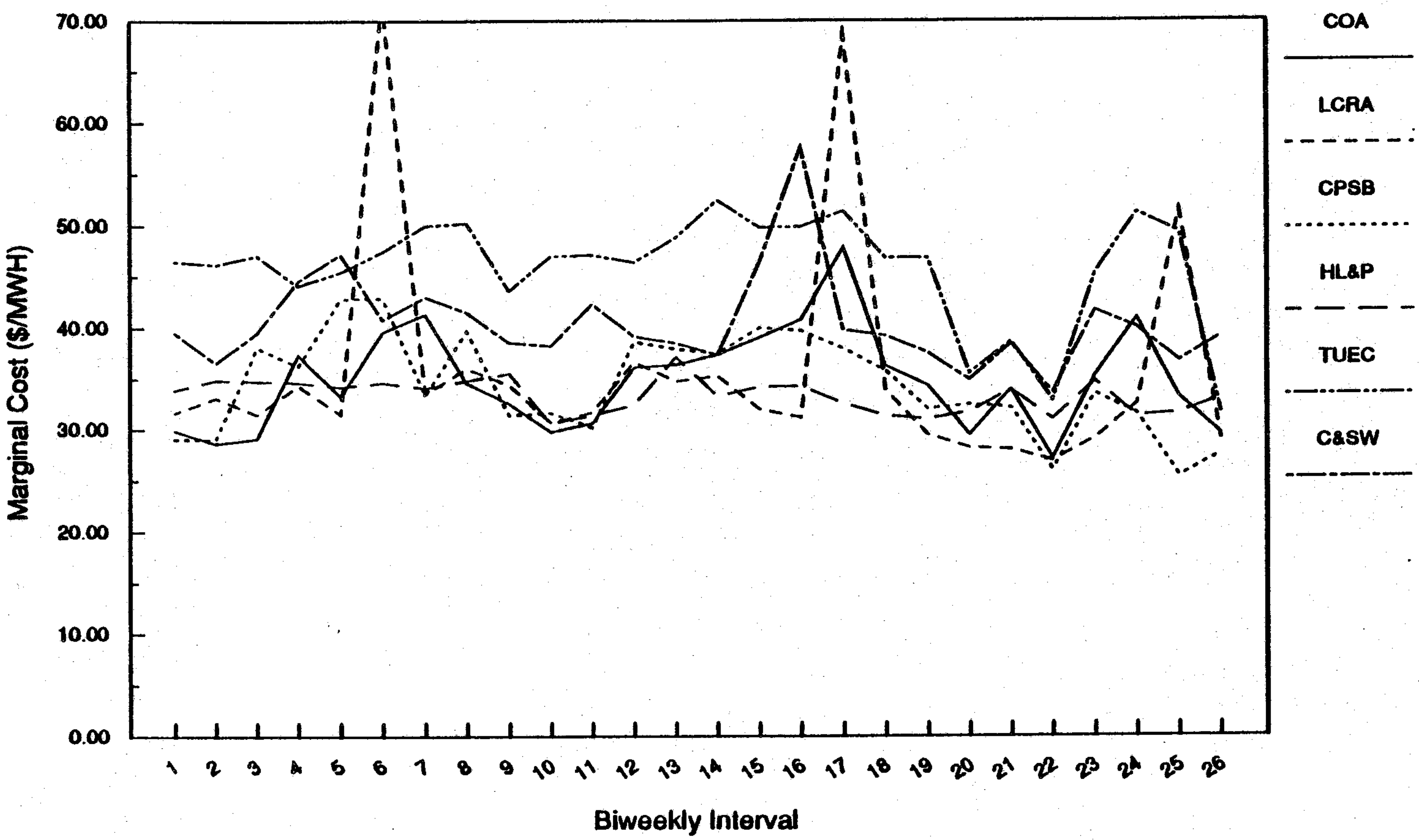


Figure 4.2-17 1995 Own-Load Marginal Cost
Reference Case - Diverging Gas Prices

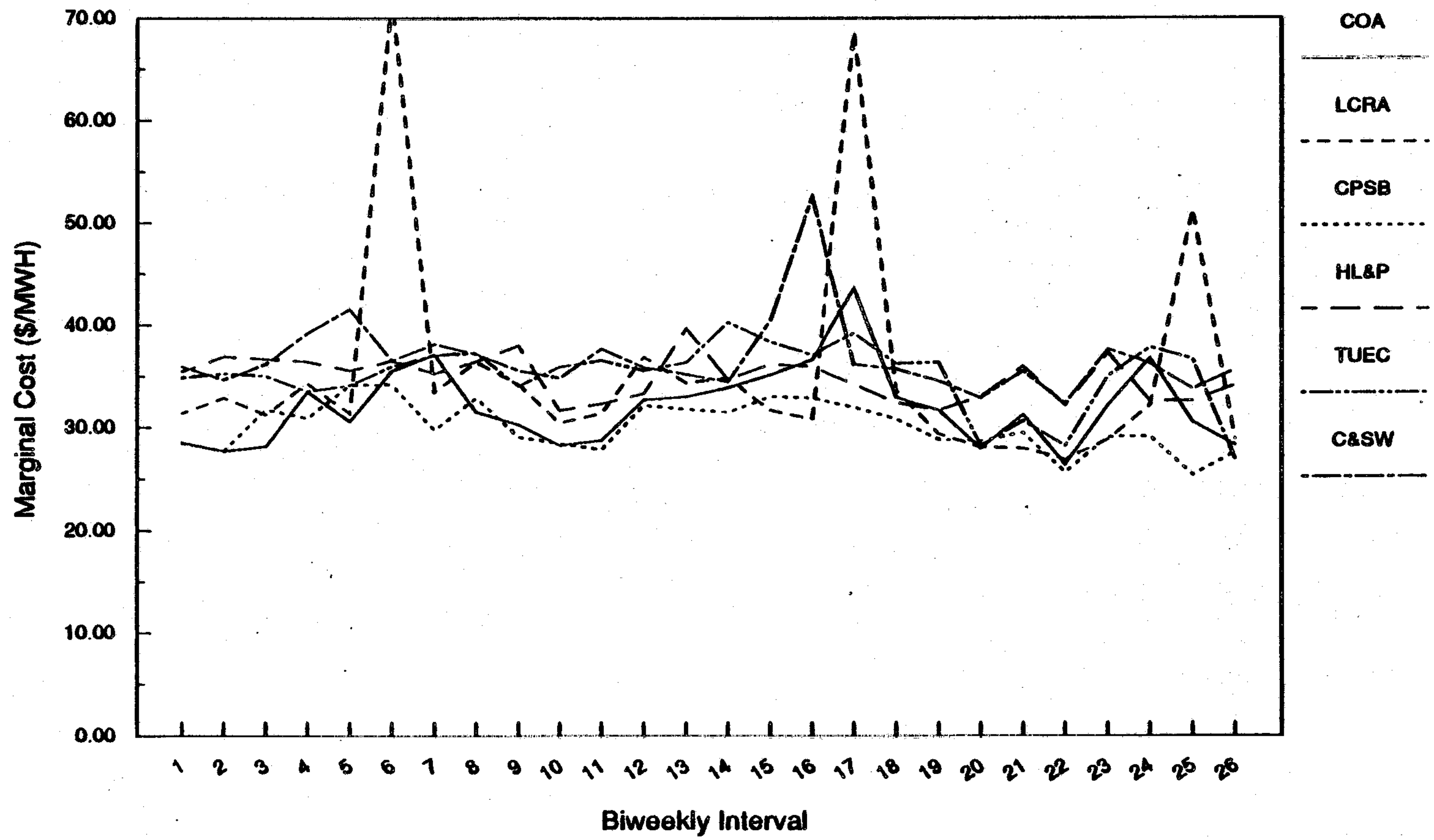


Figure 4.2-18 1995 Own-Load Marginal Cost
Reference Case - Converging Gas Prices

have been realized if ERCOT had then had mechanisms in place to fully coordinate transactions. By developing two cases based on average and incremental fuel prices, the model can also be evaluated against the utility dispatch by fuel type to determine whether the calculated transactions would have violated existing utility constraints.

The input data were taken from the database collected at the PUCT using transmission and loadflow data from ERCOT. The summary of annual generation and savings are shown in Tables 4.2-17 and 4.2-18 and indicate a reduction of more than 50% in the potential level of transactions when each utility's incremental fuel prices are used. The annual savings fall by nearly 80%. These results, based on actual monthly data provided by the ERCOT utilities and converted into annual totals and averages, provide ample support for the similar forecast results in the 1990 and 1995 reference cases.

Comparisons of generation patterns between own-load and pool operations are presented in Tables 4.2-19 and 4.2-20. It should be noted that the single fuel price limitation of the MAPS/MWFLOW model limits the ability to completely reproduce actual generation patterns which take into account the more complex interaction between fuel contracts and spot markets. The use of the average gas price in the model tends to underestimate, while the use of the incremental price tends to overestimate, their importance in determining the actual generation and fuel mix for the ERCOT utilities. Tables 4.2-21 and 4.2-22 report the estimated fuel consumption under own-load and pool operations.

The results of these simulations confirm the potential for increased bulk power transactions through increased operating coordination among the ERCOT utilities, although the current state of the natural gas market suggests that the limit of that potential is the 14.7 billion KWH associated with the incremental gas price reference case. Although the energy broker system did not come on line until November 1986, the ERCOT utilities actually exchanged 2.2 billion KWH in 1986, and 2.6 billion in the first

TABLE 4.2-17

Summary of Annual Generation and Total Savings in 1986:
Average Gas Prices

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	6,025	4,756	1,596	327	-1,269	129.7	96.7	6.7	123.0
LCRA	6,536	10,637	121	4,222	4,101	121.5	188.5	20.3	101.2
CPSB	10,828	15,057	460	4,689	4,229	218.9	311.3	16.5	202.4
HL&P	56,613	76,943	5	20,336	20,331	1,090.2	1,470.5	80.5	1,009.7
TUEC	80,180	56,152	24,126	98	-24,028	1,668.4	988.8	104.9	1,563.6
C&SW	22,524	19,161	4,412	1,050	-3,362	491.8	425.1	10.7	481.1
Total	182,706	182,706	30,720	30,720		3,720.6	3,480.9	239.6	3,480.9

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 4.2-18

Summary of Annual Generation and Total Savings in 1986: Incremental Gas Prices

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	6,025	3,023	3,070	69	-3,001	117.2	58.6	5.2	112.0
LCRA	6,536	8,084	324	1,872	1,548	119.8	141.2	5.2	114.6
CPSB	10,828	11,756	1,097	2,026	929	193.8	211.2	4.5	189.3
HL&P	56,613	65,437	88	8,912	8,824	1,044.7	1,186.8	15.9	1,028.7
TUEC	80,180	78,309	3,646	1,775	-1,871	1,202.2	1,154.6	8.8	1,193.3
C&SW	22,524	16,096	6,485	57	-6,428	417.8	291.7	11.6	406.2
Total	182,706	182,706	14,710	14,710		3,095.5	3,044.2	51.2	3,044.2

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 4.2-19

Electricity Generation by Fuel Type in 1986:
Average Gas Prices
(million KWH)

	Gas	Coal	Lignite	Oil	Nuclear	Others	Total
<u>Own-Load Operation</u>							
COA	2,201	3,824	0	0	0	0	6,025
LCRA	4,511	1,905	0	0	0	119	6,536
CPSB	5,283	5,544	0	0	0	0	10,828
HL&P	32,829	8,255	5,227	0	0	10,302	56,613
TUEC	40,330	0	37,127	0	0	2,723	80,180
C&SW	19,020	3,504	0	0	0	0	22,524
Total	104,175	23,033	42,354	0	0	13,144	182,706
<u>Pool Operation</u>							
COA	1,037	3,719	0	0	0	0	4,756
LCRA	6,918	3,719	0	0	0	0	10,637
CPSB	9,585	5,472	0	0	0	0	15,057
HL&P	49,559	11,774	5,310	0	0	10,300	76,943
TUEC	16,326	0	37,232	0	0	2,592	56,151
C&SW	16,197	2,965	0	0	0	0	19,161
Total	99,622	27,647	42,542	0	0	12,892	182,704

TABLE 4.2-20

Electricity Generation by Fuel Type in 1986:
Incremental Gas Prices
(million KWH)

	Gas	Coal	Lignite	Oil	Nuclear	Others	Total
<u>Own-Load Operation</u>							
COA	2,766	3,259	0	0	0	0	6,025
LCRA	4,771	1,646	0	0	0	119	6,536
CPSB	7,875	2,953	0	0	0	0	10,828
HL&P	34,269	7,498	4,545	0	0	10,302	56,613
TUEC	40,370	0	37,087	0	0	2,723	80,180
C&SW	20,826	1,697	0	0	0	0	22,524
Total	110,877	17,053	41,632	0	0	13,144	182,706
<u>Pool Operation</u>							
COA	374	2,649	0	0	0	0	3,023
LCRA	5,434	2,649	0	0	0	0	8,084
CPSB	8,147	3,609	0	0	0	0	11,756
HL&P	41,672	8,277	5,188	0	0	10,300	65,437
TUEC	38,485	0	37,231	0	0	2,592	78,308
C&SW	15,520	576	0	0	0	0	16,096
Total	109,632	17,760	42,419	0	0	12,892	182,704

TABLE 4.2-21

Fuel Consumption in 1986:
Average Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
Own-Load Operation						
COA	24,363	38,254	0	0	0	62,617
LCRA	43,884	19,569	0	0	0	63,453
CPSB	53,447	58,165	0	0	0	111,612
HL&P	328,536	93,091	57,381	0	0	479,008
TUEC	415,813	0	416,484	212	0	832,508
C&SW	188,815	33,064	0	4	0	221,883
Total	1,054,859	242,142	473,865	216	0	1,771,081
Pool Operation						
COA	12,538	37,189	0	0	0	49,727
LCRA	66,843	37,189	0	0	0	104,032
CPSB	96,961	57,557	0	0	0	154,518
HL&P	503,554	125,466	58,241	0	0	687,261
TUEC	177,745	0	417,706	212	0	595,663
C&SW	163,646	28,536	0	7	0	192,190
Total	1,021,288	285,937	475,947	219	0	1,783,391

TABLE 4.2-22

Fuel Consumption in 1986:
Incremental Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
<u>Own-Load Operation</u>						
COA	29,239	32,567	0	0	0	61,806
LCRA	46,230	17,424	0	0	0	63,654
CPSB	77,890	32,061	0	0	0	109,951
HL&P	342,185	87,220	50,398	0	0	479,803
TUEC	416,109	0	416,038	212	0	832,360
C&SW	210,065	17,141	0	4	0	227,210
Total	1,121,720	186,413	466,436	216	0	1,774,784
<u>Pool Operation</u>						
COA	4,760	26,886	0	0	0	31,646
LCRA	52,548	26,886	0	0	0	79,434
CPSB	81,458	38,682	0	0	0	120,140
HL&P	414,510	93,271	56,980	0	0	564,762
TUEC	391,127	0	417,691	212	0	809,031
C&SW	155,963	5,894	0	7	0	161,864
Total	1,100,367	191,619	474,672	219	0	1,766,878

nine months of 1987. The difference between actual and potential transactions indicates that the ERCOT broker system has the opportunity to grow at an even faster rate, and that the individual utilities may need to give more consideration to purchased power as a resource option. If the natural gas market should also begin to change rapidly, the incentive to find available economical energy would be further enhanced. In any case, the establishment of the brokerage system to coordinate transactions indicates that ERCOT is seeking the opportunities and making an effort to take advantage of economically and operationally feasible bulk power transactions.

4.3 Summary of Reference Case Results

The reference case results for 1986, 1990, and 1995 indicate that there are reasonable opportunities for bulk power transactions within the ERCOT system. However, the dollar values of potential annual cost savings are extremely sensitive to the particular assumptions made about the future state of the natural gas market faced by the ERCOT utilities. Because the potential economic savings are so variable, the upper limit of the potential level of transactions also is variable, but in a smaller range. The range of future potential transactions and savings is supported by the results of the historical 1986 reference cases under parallel, albeit hypothetical, assumptions about the gas market structure and prices.

Under the assumption of converging natural gas prices, such that the future markets are similar to those today, the reference case level of potential transactions is 7.1% and 6.6% of total system energy in 1990 and 1995, respectively, while the level of potential savings would be limited to 1.3% and 1.6% of system variable operating costs. Under the opposite assumption of diverging natural gas prices, in which the natural gas market returned to only a long-term market with the relative position of the utilities' gas prices unchanged, the reference case levels of potential transactions rise to 13.8% and 10.3%, respectively, while the potential savings would increase to 5.6% and 4.7%, respectively. The relative range of these variables is also supported by the reference case results from the 1986 historical year.

The primary effect of pool operation is a decrease in gas-fired generation by TUEC in each of the reference cases. This decrease is accompanied by an increase in gas-fired generation by HL&P and CPSB in the converging gas price case; or a much larger increase by only HL&P in the diverging gas price case. LCRA and COA are also net exporters of energy in the diverging gas price cases, but under converging gas prices, COA becomes a small net importer. The reference case results for C&SW is mixed between being a net importer or a net exporter, but in any of the cases, the net amount of energy is small in relation to the total C&SW load.

If the method of split savings discussed in Appendix A were used, TUEC would be the primary beneficiary of a pool operation in all of the reference cases, with potential annual savings ranging from 1.2% (assuming converging gas prices in 1995) to 5.4% (assuming diverging gas prices in 1990). Because of TUEC's tight capacity conditions, these savings are a result of reducing output from relatively inefficient gas units which may also be fueled by relatively expensive natural gas. HL&P, the primary exporter, would accrue the second highest level of annual savings in all of the reference cases although CPSB exports more energy in the 1995 converging gas price case. All of the other ERCOT members would experience annual savings from pool operation as well. These savings estimates do not include the effects of wheeling charges or incremental transmission losses.

Under normal operating conditions, the transmission system appears to be theoretically capable of supporting the high levels of transactions shown with diverging gas prices.

However, the reserve capacity of the ERCOT transmission system may be reduced to an inadequate level causing the system to be less stable as well as less reliable. The model results show that several transmission lines are loaded to their capacity limits during some time periods to accommodate these transactions and would not be available for emergency shipments of power which may cause a serious service curtailment. If the transmission system were modified to address these concerns, the cost of the modifications would reduce potential total savings. In the case of converging gas prices, the level of transactions is much lower so that potential reliability considerations are reduced, although not totally eliminated.

Chapter 5
Alternative Scenarios

The results of the reference cases in the previous chapter provide an estimate of potential bulk power transactions and cost savings which may be realized through system coordination for two alternative views of future natural gas prices. In addition to gas prices, however, these estimates may be affected by other factors which may deviate from the reference case assumptions. In this chapter several scenarios are explored in order to examine the effects of changing such parameters as transmission system limitations, degrees of system coordination, demand forecast uncertainty, nuclear power uncertainty, alternative fuel prices, cogeneration, potential gas supply disruption and DC interconnection with neighboring reliability councils. Although some of these factors may vary under either diverging or converging gas prices, their impacts are the greatest when the higher, diverging gas prices are used. Therefore, these alternative scenarios are implemented with diverging gas prices only.

In the earlier transmission system limitation scenarios, additional lines were monitored under normal and contingency conditions. The contingency conditions were derived from the **Transfer Limitation Study** performed by ERCOT in 1986 and 1987. With the addition of some 200 monitored lines in all of the reference cases, the additional monitored line case would be a redundancy and thus, no longer appears. Following the December review meetings, further staff investigation revealed that the model considered only partial transmission line contingencies, and did not consider the possible loss of generating capacity -- a more serious contingency condition which poses the greatest reliability problems for the ERCOT system. Thus, in order to avoid any misinterpretation, the earlier "contingency" scenario has been dropped. The remaining transfer limit scenario, which uses a different solution algorithm, constrains the transfer capability to the levels reported in the 1987 ERCOT **Transfer Limitation Study**. This scenario now provides an estimate of the impacts of the transmission limitations on the economics of bulk power transactions under ERCOT's defined outage conditions.

The alternative coordination arrangement scenarios are implemented in order to measure the impacts of different degrees of coordination. In this section, two alternative coordination arrangements are compared. In one arrangement, the utilities are assumed to exchange only non-firm energy, as opposed to the reference cases in which both firm and non-firm energy are exchanged. In the other arrangement, the utilities are assumed to enhance the pooling operation by coordinating their maintenance scheduling.

In the demand sensitivity scenarios, alternative demand projections by the PUCT and the utilities are used to analyze the effects of levels of demand on the bulk power interchanges.

In the nuclear power uncertainty scenario, two test cases are made which assume the loss of a unit of the Comanche Peak Nuclear Station or a unit of the South Texas Nuclear Project for the entire year of 1990. These scenarios examine how bulk power transactions could be used to mitigate the impacts of losing a nuclear (or any other large) generating unit.

The alternative fuel price scenarios examine the potential changes in bulk power transactions based on fuel substitution under various conditions of natural gas and other fuel markets.

The cogeneration scenarios are implemented to examine the contribution of cogeneration to the interconnected system, focusing on fuel displacement. Alternative levels of cogeneration supply are modeled to measure the fuel displacement of conventional utility generation by cogeneration.

In the gas supply disruption scenario, historical data are analyzed and a list of operational problems encountered during the extremely cold weather experienced in the winter of 1983 is compiled. The utilities' preventive measures in response to the cold weather supply disruption are also examined.

Finally, the DC interconnection scenario represents an attempt to investigate the economic benefits of power exchange between ERCOT and other reliability councils. Unfortunately, the data obtained from adjoining power pools were inadequate for meaningful technical implementation of the scenario. And, since the December draft of this report, the PUCT General Counsel's office has provided the study staff with a legal opinion which is discussed in Section 5.8.

5.1 Transmission System Limitation

Two cases using a different solution method are created to explore the transmission limitations of the ERCOT system under no-outage and outage conditions. Only the 1990 system configuration is examined. The first case is used to provide a benchmark test against the transactions level in the diverging price reference case. The second case then imposes the transfer limits under defined outages for the summer peak hour with the assumption that such outages would persist for the entire year in order to evaluate the maximum potential transfer reduction.

In these two cases, individual transmission lines are not explicitly modeled. Instead, it is assumed that there is a lump sum of "transfer limit" between any two utilities that is independent of load and generation level. The transfer limits during peak hours under the outage and no-outage conditions are presented in Tables 5.1-1 and 5.1-2, respectively. These data are taken from the ERCOT 1987 **Transmission Limitation Study**.

TABLE 5.1-1

1990 Transfer Limits : No Outage Case
(MW)

	Delivering Utility						
Importing Utility	COA	LCRA	CPSB	HL&P	TUEC	CP&L	WTU
COA		568	743	592	463	486	531
LCRA	1592		1522	1180	759	496	929
CPSB	1041	2336		1482	1325	472	1962
HL&P	1560	1598	1844		2216	488	2052
TUEC	1306	1668	1691	1136		471	1861
CP&L	400	2205	1268	1471	1397		2052
WTU	1168	1203	1203	1178	1370	458	

TABLE 5.1-2

1990 Transfer Limits : Outage Case
(MW)

Importing Utility	Delivering Utility: COA	LCRA	CPSB	HL&P	TUEC	CP&L	WTU
COA		147	122	121	127	120	128
LCRA	1062		977	987	575	458	693
CPSB	420	1265		1054	801	366	865
HL&P	914	1204	1211		922	427	832
TUEC	411	416	446	578		429	799
CP&L	500	1361	1066	1392	900		860
WTU	336	355	367	453	1016	382	

While the solution technique is expected to give less accurate results, the comparison between the no-outage and outage cases should approximately quantify the reduction in transactions and savings when the outage conditions are imposed on the transmission system. The results from these two cases are presented in Table 5.1-3.

As shown in Table 5.1-3, the no-outage case results in 29,477 million KWH of transactions and $257.4 million of savings which are higher than the results in the reference case (diverging gas prices) by 5.3% and 4.0% respectively. The similarity in results from the two cases are as expected because, although different solution methods are employed, the basic assumptions are the same. Thus, these results support the reference case results based on diverging fuel prices and provide a benchmark for comparison with the outage case.

The outage case reflects the reliability criteria adopted by ERCOT members for day to day operation where as the system must survive the first contingency. By operating within the limit of the contingency conditions, system operators can be certain that no single outage will cause problems to the system. As shown in Table 5.1-3, when the outage condition is imposed, the overall transaction level is reduced from 29,477 million KWH to 20,955 million KWH (-28.9%), while savings are reduced from $257.4 million to $187.2 million (-27.2%). Applying the percentages to the reference case results would indicate that under contingency conditions, the level of transactions would be limited to 19,912 million KWH while comparable savings would be reduced to $180.0 million.

If actual gas market conditions become such that greater levels of transactions are possible, these contingency results can represent the absolute upper limits for firm transactions within existing ERCOT guidelines which require that the capacity of the transmission system be operable after the occurrence of the first contingency. Any levels of exchange greater than these limits would need to be fully interruptible. Under such

TABLE 5.1-3

Summary of Interchange and Savings in 1990:
ERCOT Transfer Limitation

	Interchange (million KWH)						Savings ($ million)	
	No Outage			Outage			No Outage	Outage
	Purchases	Sales	Net Sales	Purchases	Sales	Net Sales		
COA	400	2,077	1,677	83	4,091	4,008	9.6	11.5
LCRA	314	3,296	2,982	385	2,241	1,856	15.9	11.6
CPSB	2,086	367	-1,719	3,179	221	-2,958	12.8	16.5
HL&P	53	21,522	21,469	51	13,826	13,775	96.6	66.4
TUEC	24,987	383	-24,604	12,781	430	-12,351	113.5	70.3
C&SW	1,637	1,832	195	4,476	146	-4,330	9.0	10.9
Total	29,477	29,477		20,955	20,955		257.4	187.2

conditions, substantially different provisions would have to be made for spinning reserve throughout the system and would further reduce the potential savings.

This reduction in savings can be viewed as an opportunity cost of not being able to exchange power due to the system limitations. This type of analysis also indicates the need for new transmission lines to insure that the reliability of the system is not degraded at higher transfer levels. In the case of converging gas prices, the reference case level of transactions, 14,357 million KWH, is about 28% less than the contingency limits shown above suggesting less potential for serious reliability problems.

5.2 Alternative Coordination Arrangements

The purpose of this section is to examine the effects of alternative degrees of coordination upon the level of transactions among ERCOT members in 1990. The pool operations discussed in Chapter 4 and other sections in Chapter 5 do not include coordinated maintenance scheduling among ERCOT members. The first scenario in this section examines the impact of including coordinated maintenance scheduling in a pool operation arrangement, and thus reflects a greater degree of coordination than the pool operations in the reference case.

The results from the first scenario are shown in Table 5.2-1. The level of transactions increases from 28,005 million KWH in the reference case to 28,615 million KWH, an increase of only 2.2%. The total savings increase from $247.2 million in the reference case to $252.9 million under pool operations with coordinated maintenance, an increase of only 2.3%. The slight increases in transactions and savings indicate that the result from the reference case is already approaching the optimum and coordinated maintenance does not yield any significant improvement over the ERCOT maintenance scheduling in the reference case.

TABLE 5.2-1

Summary of Annual Generation and Total Savings in 1990: Coordinated Maintenance Scheduling

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,024	8,428	467	1,872	1,405	129.1	160.1	9.7	119.5
LCRA	7,858	10,916	171	3,229	3,058	170.1	239.8	14.7	155.4
CPSB	13,227	11,016	2,664	452	-2,212	279.4	201.9	15.7	263.7
HL&P	56,165	77,375	34	21,244	21,210	1,257.2	1,724.8	97.0	1,160.3
TUEC	94,338	71,245	23,372	279	-23,093	2,010.4	1,270.9	107.7	1,902.6
C&SW	24,052	23,684	1,908	1,539	-369	551.8	547.6	8.1	543.7
Total	202,664	202,664	28,615	28,615		4,398.1	4,145.2	252.9	4,145.2

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

The second scenario in this section simulates a level of coordination characteristic of the ERCOT brokerage system where only non-firm transactions are involved. Unlike the reference case where the units are committed to minimize the cost of the entire pool, in this alternative scenario each company first commits its own units to meet its native load. In the reference case, some utilities may not have enough reserves to supply their own load. Thus, at least some of their purchased power would have to be non-interruptible. In this alternative scenario, each utility always maintains adequate reserves to meet its native demand. Therefore, the potential transactions are fully interruptible.

The results from the non-firm transactions scenario are shown in Table 5.2-2. The level of transactions decreases to 11,964 million KWH while total savings decrease to $82.4 million when the commitment logic is constrained to satisfy these native load criteria. This constraint decreases the level of transactions by approximately 57% and the total savings by nearly 67%. The results indicate that an ERCOT brokerage system based upon only non-firm energy transactions captures less than half of the benefits which could be derived from fully coordinated operations. The other share of the savings achieved by pool operations is presumably due to capacity transactions, under which one utility makes a firm commitment to provide power to another utility. Recognition of these expanded opportunities may be facilitated by information gained through more experience with the operation of the brokerage system and might lead to additional contract purchases. Such purchases combined with non-firm transactions should not exceed the reliability limits suggested in Section 5.1.2.

5.3 Demand Growth Sensitivity

Electricity demand is among the most important factors that determine the economic feasibility of bulk power transmission in Texas. Since the construction period for most

TABLE 5.2-2

Summary of Annual Generation and Total Savings in 1990:
Non-Firm Transactions

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,024	8,213	49	1,238	1,189	126.0	153.6	4.8	121.2
LCRA	7,858	9,384	197	1,723	1,526	170.8	204.3	8.6	162.2
CPSB	13,227	14,325	228	1,326	1,098	276.2	303.0	4.1	272.1
HL&P	56,165	59,723	160	3,719	3,559	1,256.7	1,334.6	15.1	1,241.6
TUEC	94,338	84,093	10,685	440	-10,245	2,005.2	1,678.1	39.0	1,966.2
C&SW	24,052	26,927	645	3,519	2,874	546.1	624.9	10.7	535.4
Total	202,664	202,664	11,964	11,964		4,381.0	4,298.6	82.4	4,298.6

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

base load plants is from 7 to 10 years and the lifetime from 30 to 40 years, capacity planning relies heavily on long-term demand forecasts. As a result, excess capacity or capacity shortfalls can occur when realized demand does not match forecasted demand. In both cases, the economics of power pooling can be affected. In general, excess capacity for a utility creates an opportunity to sell energy economically to other utilities within the system, while a shortfall in capacity leads to a purchase of energy from neighboring utilities. Thus, an optimal power interchange pattern which depends upon demand conditions and the capacity structure of the participating utilities, may be determined.

5.3.1 Demand Uncertainty in Texas

The impact of changes in electricity demand is discussed under the assumption that capacity additions and retirements, fuel prices, and other cost parameters remain constant. The demand for electricity is frequently expressed as a function of demographic factors, weather variables, energy prices, and other economic indicators. The utilities' revised demand projections are significantly lower than those anticipated only a few years ago. This is due to the recent economic slowdown in the state of Texas and changes in consumption characteristics in response to changes in energy prices and utility sponsored conservation/load management programs. Residential and commercial customers are expected to implement conservation measures to increase their energy efficiency while industrial customers may seek alternative sources of electricity to reduce their overall energy costs in addition to implementing conservation measures.

Table 5.3-1 contrasts the demand forecasts filed by the utilities in December 1985 with revised forecasts reported by some utilities in 1987. The numbers illustrate the difficulties and degree of uncertainty that the forecasters are facing. In recent years, the

TABLE 5.3-1

Changes in Utility Peak Demand Forecast
(MW)

	1990			1995		
	1986 Forecast	Recent Update	Change (%)	1986 Forecast	Recent Update	Change (%)
COA	1,786	1,786	0.0	2,281	2,281	0.0
LCRA	2,016	1,511	-25.0	2,943	1,901	-35.4
CPSB	2,969	2,974	0.2	3,687	3,689	0.0
HL&P	11,926	10,201	-14.5	14,101	11,201	-20.6
TUEC	18,053	17,998	-0.0	20,910	20,854	-0.0
CP&L	3,309	3,213	-2.9	4,159	3,848	-7.5
WTU	1,346	1,314	-2.4	1,467	1,468	0.0

(Source)
1986 Forecast : Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1986, Volume 2.
Recent Forecast : Load forecast obtained from utilities as of April 1987.

changes in Texas economy have been quite drastic, which is reflected in the downward revision of the demand projections. For example, LCRA reduced its 1995 projected demand by 35.4 percent from last year. Similarly, HL&P also reduced its 1995 projected demand by 20.6 percent. These uncertainties make accurate long-range capacity planning extremely difficult. Two potential extreme results would be for all utilities to have excess capacity or for all utilities to have capacity shortages. A more likely situation is that some utilities would have shortages while others would have excess capacity, thus providing the potential for exchanges of power.

To analyze bulk power transactions under demand uncertainties, demand projections by the PUCT and the utilities are used to examine demand sensitivity in 1990 and 1995. The utility projections are obtained from individual utilities as of November 1987. These projections are shown in Table 5.3-1. The reference cases are based on the columns labeled "Recent Update" while the High and Low Projection Cases are 5% above and below those values. Only the years 1990 and 1995 are investigated in this analysis.

Please note that the use of the recent update utility projections in the reference case for both 1990 and 1995 is a substantial change from the forecasts that were called the "base case" in earlier versions of this report and, thus the range of the forecasts from High to Low is considerably lower as well.

5.3.2 Results

The discussion in this section focuses on the interchange patterns and savings for 1990 and 1995. The savings are the differences in variable operating costs between the hypothetical own-load and pool operations. Note that the capacity projections are assumed to be the same in all the test cases.

5.3.2.1 Reserve Margins

One of the factors which determines the level of transactions is the amount of excess capacity available for export. It is represented by the annual reserve margin which is the difference between total installed capacity and annual peak demand expressed as a percent of annual peak demand. If all other parameters are identical, utilities with higher reserve margins will tend to export power to those with lower reserve margins.

The reserve margins under the different demand cases for 1990 and 1995 are shown in Figures 5.3-1 and 5.3-2, respectively. In the reference case for 1990, COA, LCRA, and HL&P reserve margins are expected to be over 30%, while TUEC's reserves have fallen to less than 20%. In the low and high cases for 1990, the demand is adjusted for all utilities by the same proportion. Therefore, the reserve margins in the low case are higher for all utilities while the reserve margins in the high case are lower for all utilities.

In the reference case for 1995 LCRA, CPSB, and HL&P reserve margins are expected to be over 25%, while COA, C&SW, and TUEC reserve margins have fallen to less than 20%. In the low and high cases for 1995, demand is again adjusted for all utilities by the same proportion. Therefore, the reserve margins in the low case are higher for all utilities while the reserve margins in the high case are lower for all utilities.

5.3.2.2 Energy Interchange and Savings

As explained earlier, energy interchange takes place whenever an opportunity arises for more economical units to be utilized in place of less economical units. The sensitivity to demand is such that the projected level of energy transactions for some utilities can change considerably from one case to another. In addition, the location and timing of either excess supply or a demand shortfall is crucial in determining the feasibility of transactions within the transmission network.

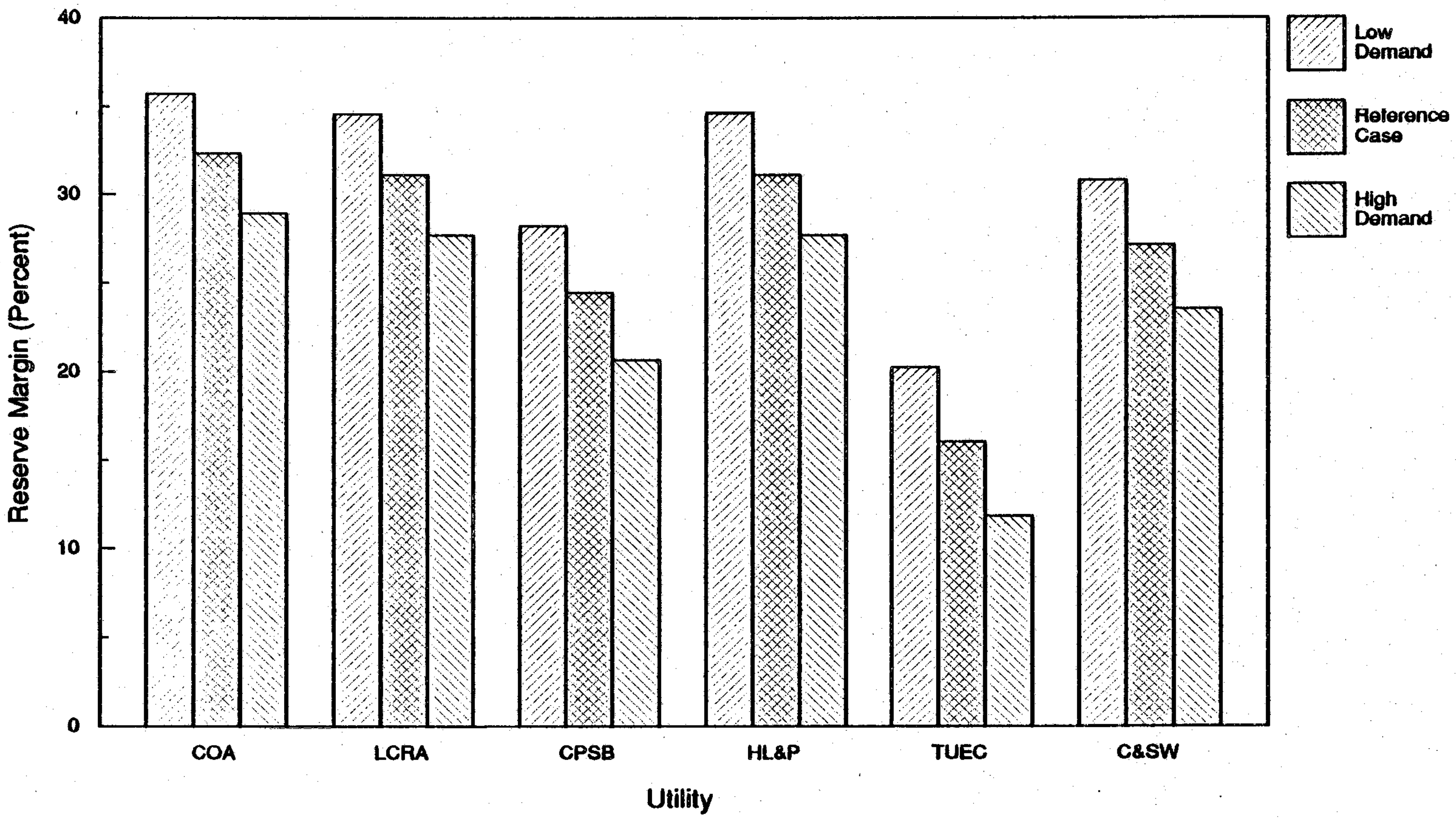


Figure 5.3-1 1990 Annual Reserve Margin for Demand Cases

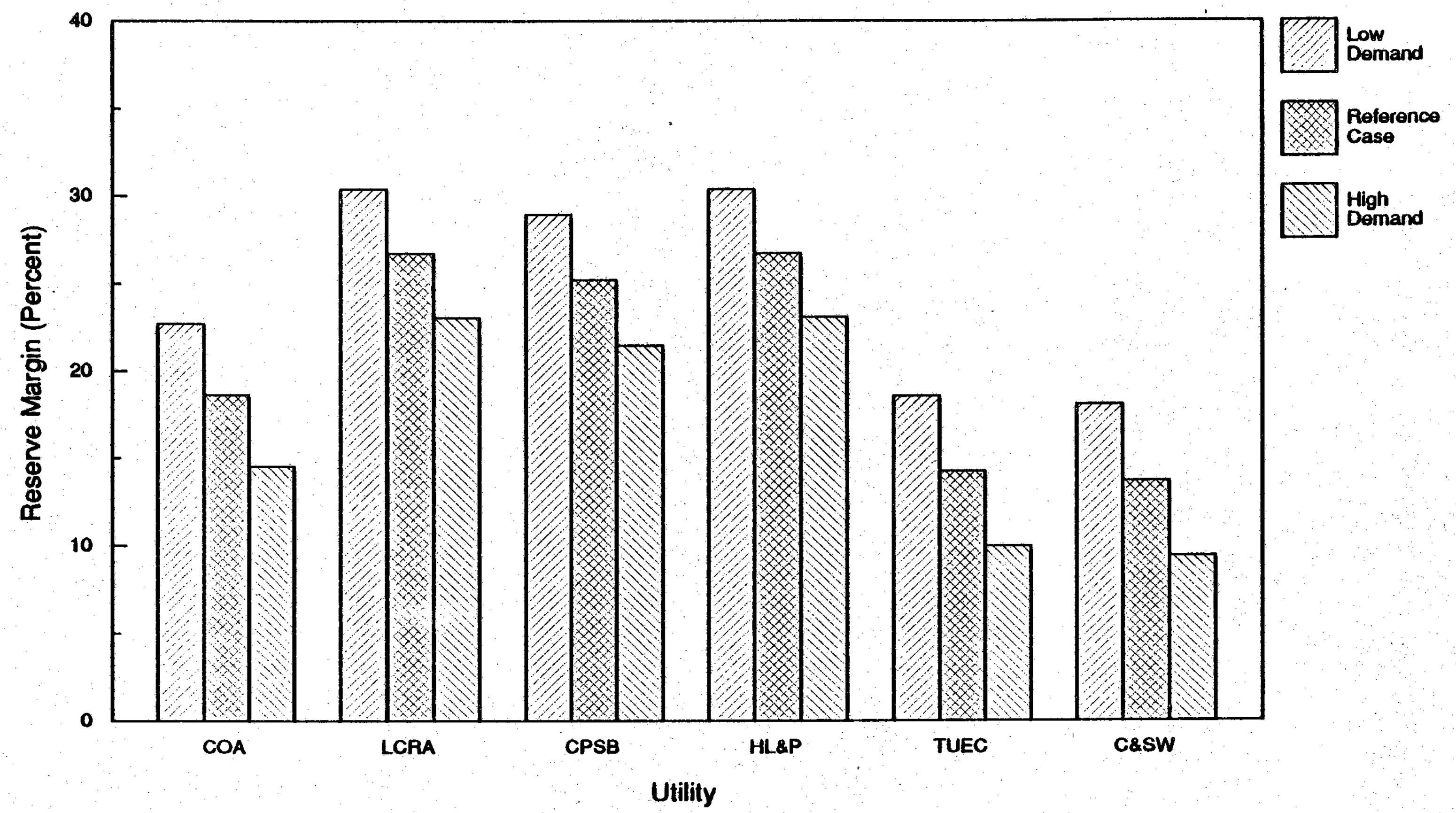


Figure 5.3-2 1995 Annual Reserve Margin for Demand Cases

Tables 5.3-2 and 5.3-3 show the 1990 annual summary of energy interchange and savings for the low demand case and high demand case, respectively. The summary for the utility-projected demand case, which is the reference case, is shown in Table 4.2-1. The amount of energy interchanged indicates that TUEC is still the largest buyer, while HL&P is the largest seller. In general, changes in demand can contribute significantly to changes in the amount of power transactions while the direction of interchange remains the same.

In the low demand case, transactions fall by 4.3% while savings are reduced by 5.3%. In the high demand case, transactions change by the nearly negligible amounts of 1.5% and 2.5%, respectively. This latter result is another indication that the transmission system capacity is being fully utilized in the reference case and that changes in other parameters do not appreciably increase the limit.

Tables 5.3-4 and 5.3-5 show the 1995 annual summary of energy interchange and savings for the low and high demand cases, respectively. The summary for the utility-projected demand case, which is the reference case, is shown in Table 4.2-3. The amount of energy interchange indicates that TUEC is still the largest buyer, while HL&P is the largest seller.

In the low demand case, transactions fall by 6.1% while savings are reduced by 3.6%. In the high demand case, transactions and savings increase by 7.6% and 6.2%, respectively. This latter result is an indication that while the transmission system capacity is being almost fully utilized in the reference case, TUEC's generation capacity shortfall requires it to import more energy to compensate for the increased demand on its resources.

TABLE 5.3-2

Summary of Annual Generation and Total Savings in 1990:
Low Demand

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	6,641	7,646	487	1,491	1,004	118.4	139.7	7.9	110.6
LCRA	7,445	10,360	357	3,273	2,916	161.3	227.5	15.1	146.2
CPSB	12,566	10,360	2,494	289	-2,205	261.1	182.3	16.1	245.1
HL&P	53,357	73,403	64	20,111	20,047	1,199.7	1,635.3	89.6	1,110.1
TUEC	89,621	68,666	21,402	446	-20,956	1,858.6	1,193.8	98.5	1,760.1
C&SW	22,867	22,061	1,999	1,193	-806	516.5	503.0	6.9	509.6
Total	192,496	192,496	26,803	26,803		4,115.6	3,881.6	234.0	3,881.6

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 5.3-3

Summary of Annual Generation and Total Savings in 1990: High Demand

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,407	9,257	392	2,243	1,851	137.2	182.4	10.3	126.9
LCRA	8,272	11,328	202	3,259	3,057	180.5	248.9	16.0	164.5
CPSB	13,888	12,197	2,166	475	-1,691	298.6	239.8	12.2	286.3
HL&P	58,973	79,804	41	20,872	20,831	1,313.6	1,780.4	96.1	1,217.5
TUEC	99,055	75,431	23,894	271	-23,623	2,174.3	1,404.6	112.3	2,062.0
C&SW	25,238	24,815	1,722	1,299	-423	584.9	579.9	6.2	578.7
Total	212,833	212,833	28,418	28,418		4,689.1	4,436.0	253.2	4,436.0

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 5.3-4

Summary of Annual Generation and Total Savings in 1995:
Low Demand

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	8,718	8,570	963	815	-148	234.8	222.1	11.9	222.9
LCRA	9,678	11,511	497	2,330	1,833	301.3	363.7	20.3	280.9
CPSB	16,105	17,046	947	1,888	941	449.4	452.5	26.2	423.2
HL&P	58,691	73,212	736	15,257	14,521	1,769.8	2,280.5	113.8	1,656.0
TUEC	108,616	93,340	17,061	1,785	-15,276	3,338.0	2,498.0	147.4	3,190.6
C&SW	27,297	25,427	3,017	1,147	-1,870	928.1	862.8	22.2	905.9
Total	229,106	229,106	23,222	23,222		7,021.4	6,679.6	341.8	6,679.6

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 5.3-5

Summary of Annual Generation and Total Savings in 1995:
High Demand

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	9,702	10,850	569	1,717	1,148	274.1	318.8	14.0	260.1
LCRA	10,740	12,638	410	2,308	1,898	340.6	402.3	20.6	319.9
CPSB	17,801	20,356	337	2,893	2,556	514.1	603.5	21.5	492.6
HL&P	64,869	81,384	602	17,118	16,516	1,971.3	2,572.4	129.3	1,842.0
TUEC	120,050	99,100	22,186	1,236	-20,950	3,919.2	2,791.1	169.0	3,750.2
C&SW	30,112	28,945	2,530	1,363	-1,167	1,055.1	1,009.6	22.3	1,032.8
Total	253,273	253,273	26,635	26,635		8,074.4	7,697.7	376.7	7,697.7

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

5.3.3 Summary of Demand Sensitivity Scenarios

Under demand variations the direction of power flow is not changed significantly but the amount exchanged is altered. When the demand forecast is lowered the level of transactions and savings are lowered, approximately in proportion to the change in demand. However, the converse with high demand is not necessarily true. Higher demands can be accommodated only if transmission capacity is available. In all of the cases TUEC remains the major buyer while HL&P remains the major seller. This is not unexpected because the two companies combined comprise over 70 percent of generating capability of the utilities in the model.

With uncertainties in demand projections, the utilities can still take advantage of power exchanges to lower operating costs. The level of transactions and savings depend on the relationship of demand to generating capacity surplus or deficit. For selling utilities, increases in demand will increase the amount of exports. For buying utilities, increases in demand will provide greater incentives to buy more.

5.4 Nuclear Power Uncertainties

The following two cases examine the potential benefits of system coordination under supply interruptions. In one case, a unit of Comanche Peak is assumed to be unavailable. In the other, a unit of the South Texas Nuclear Project is assumed to be unavailable. The reasons for the supply curtailments are not addressed.

5.4.1 Impacts of Losing Nuclear Units: Own-Load Operations

Table 5.4-1 shows the operating costs of individual systems under own-load operations when one of the two nuclear units do not produce any electricity. As expected, the losses

TABLE 5.4-1

1990 Generation and Operating Costs under Nuclear Uncertainty Cases: Own-Load Operations

	Generation (million KWH)	Operating Cost ($million)* Reference Case	Operating Cost ($million)* Losing a Unit of Comanche Peak	Operating Cost ($million)* Losing a Unit of South Texas
COA	7,024	127.7	127.7	145.8
LCRA	7,858	170.9	170.9	172.0
CPSB	13,227	279.4	279.4	316.1
HL&P	56,165	1,256.4	1,256.4	1,279.6
TUEC	94,338	2,013.6	2,156.0	2,013.6
C&SW	24,052	550.0	550.0	583.0
Total	202,664	4,398.0	4,540.4	4,510.1

* Costs include only fuel and variable O&M.

of the nuclear units increase total operating costs. In the reference cases where both nuclear units are available, the total operating cost of all the systems is $4,398.0 million. In the event of losing a Comanche Peak or a South Texas unit, the total operating costs rise to $4,540.4 million and $4,510.1 million, respectively.

Under own-load operations, only owners of the unavailable units are affected, except for a slight increase in operating cost for LCRA which is due to increased use of generating resources which it jointly owns with COA. The overall impact is less severe in the South Texas case. One possible explanation is that the owners of the South Texas units generally have higher reserve capacities than TUEC, the only Comanche Peak owner modeled in this study. Owners of the South Texas unit such as COA and HL&P still have relatively low-cost units to compensate for the loss of the nuclear unit. On the other hand, TUEC must use relatively expensive units to make up for the loss of the Comanche Peak unit.

5.4.2 Impacts of Losing Nuclear Units: Pool Operations

Table 5.4-2 shows the impact of losing a nuclear unit under pool operation. Losing either the Comanche Peak or the South Texas unit raises the total pool operating cost from $4,150.8 million to $4,256.2 and $4,269.0, respectively. Compared to the own-load operation, power pooling results in savings of $284.2 million in the case of losing the Comanche peak unit and $241.1 million in the case of losing the South Texas Unit.

Under pool operations, losing the nuclear units affects both operating costs and energy exchange patterns. In the case of losing Comanche Peak, only TUEC is negatively affected. Under pool operation, the impacts are less severe. For example, without power pooling, losing the Comanche Peak unit would increase TUEC's operating cost to $2,156.0 million. With power pooling, losing the Comanche Peak unit would bring

TABLE 5.4-2

1990 Generation and Operating Costs Under Nuclear Power Uncertainty Cases: Pool Operations

	Generation (million KWH)			Adjusted Operating Cost ($million)*		
	Reference Case	Losing a Unit of Comanche Peak	Losing a Unit of South Texas	Reference Case	Losing a Unit of Comanche Peak	Losing a Unit of South Texas
COA	8,444	8,804	7,957	118.6	117.7	136.8
LCRA	10,872	11,139	11,317	155.4	153.9	155.7
CPSB	11,156	11,508	9,873	265.4	266.7	299.9
HL&P	76,957	78,818	77,767	1,161.5	1,146.3	1,186.2
TUEC	71,552	68,090	72,612	1,905.9	2,027.5	1,914.5
C&SW	23,684	24,306	23,138	544.0	544.2	575.9
Total	202,664	202,664	202,664	4,150.8	4,256.2	4,269.0

* Costs include only fuel and variable O&M.

TUEC's operating cost to $2,027.5 million, a saving of $128.5 million. Losing the Comanche Peak unit also increases power transactions between TUEC and the other utilities. The results shown in Table 5.4-2 indicate an increase in generation from the other five systems when TUEC loses the Comanche Peak unit. These increases in generation result in more energy sales to TUEC and more net savings to the sellers.

In the case of losing the South Texas unit, all the utilities are affected, including TUEC. Unlike the Comanche Peak case, losing the South Texas unit causes a reduction in power transactions. This is because all owners of the South Texas unit are net exporters except CPSB. Losing the unit decreases their capabilities to sell power. The resulting decrease in power transactions reduces benefits to both buyers and sellers and total savings fall by 2.7%.

5.4.3 System Reliability

The loss of Comanche Peak under the own-load operation increases the probability of capacity deficiency during the summer peak intervals in 1990. Similarly, annual generation requirements include a small amount of emergency energy. Under the pool operation, TUEC can import energy to make up for these deficiencies, demonstrating that increased system coordination helps improve system reliability as well as operating economies.

5.4.4 Summary of Nuclear Power Uncertainty Case Results

The results of the two cases where the systems are tested under conditions in which large economical units become unavailable demonstrate that the benefits from increased system coordination extend far beyond short-term economies under normal operating conditions. System coordination to allow bulk power transfer also gives the system more capability to mitigate the impacts of prolonged supply disruptions. The results from these two cases also reinforce the finding in the reference cases that excess capacity is one of the most important driving factors in bulk power transactions.

5.5 Fuel Scenarios

The price volatility that natural gas and oil have exhibited in the past two decades indicates that fuel price is a substantial source of uncertainty in production cost forecasting. Indeed, it is this fundamental uncertainty which required the addition of the converging gas price reference cases in Chapter 4. As a result of that change, the earlier cases with differing fuel prices found in (then) sections 5.5.1 through 5.5.6 are no longer necessary. In this section, only two additional scenarios are developed in order to determine whether the effects of other variations in fuel prices have any significant effect on the level of transactions and savings. Only comparisons to the diverging gas price reference cases are necessary, as will be explained in the summary in Section 5.5.3.

5.5.1 1990 High Gas Prices

The 1990 high gas price case assumes that the natural gas prices paid by utilities in the diverging gas price reference case are increased by 10% across the board. As shown in Table 5.5-1, when compared to the reference case results in Table 4.2-11, the primary effect is to increase inter-fuel substitution in both own-load and pool operation. Most of this substitution comes from coal-fired generation where BTU consumption increases by approximately 20,000 billion BTU while gas consumption decreases by a like amount. Total BTU consumption is nearly unchanged which indicates that relative efficiency of the more heavily loaded coal units is comparable to the gas units being backed down.

TABLE 5.5-1

Fuel Consumption in 1990:
High Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
Own-Load Operation						
COA	14,723	34,340	0	0	23,529	72,591
LCRA	18,748	59,964	0	0	0	78,712
CPSB	39,133	57,023	0	0	40,532	136,687
HL&P	239,406	107,059	92,720	0	45,116	484,301
TUEC	405,936	0	409,681	226	128,464	944,307
C&SW	121,583	81,582	0	12	37,494	240,671
Total	839,528	339,967	502,401	238	275,136	1,957,270
Pool Operation						
COA	23,844	38,728	0	0	23,800	86,372
LCRA	41,378	66,497	0	0	0	107,875
CPSB	14,459	61,416	0	0	41,651	117,526
HL&P	406,340	137,030	96,747	0	45,816	685,934
TUEC	173,691	0	414,861	226	128,477	717,256
C&SW	127,909	79,665	0	8	37,486	245,067
Total	787,621	383,336	511,609	233	277,230	1,960,029

The effect on transactions can be seen by comparing Table 5.5-2 with the reference case in Table 4.2-1. The total cost for both own-load and pool operation are shown to increase, as expected, and total savings increases from $247.2 million to $284.7 million. However, the more significant result is that the level of transactions remains nearly constant, decreasing only from 28.0 billion KWH to 27.7 billion KWH (1.0%). This result also supports the conclusion that the diverging gas price reference case is the upper bound of transactions and that upward changes in the gas price only inflates the level of savings disproportionately by some 15% with no real improvement in system operations.

5.5.2 1995 High Gas Prices

The 1995 high gas price case also assumes that the natural gas prices paid by utilities in the diverging gas price reference case are increased by 10% across the board. As shown in Table 5.5-3, when compared to the reference case results in Table 4.2-13, the primary effect is again to increase inter-fuel substitution in both own-load and pool operation. In this case, too, most of this substitution comes from coal-fired generation where BTU consumption increases by approximately 10,000 billion BTU while gas consumption decreases by a like amount. Again, total BTU consumption in this case is nearly unchanged which indicates that the relative efficiency of the more heavily loaded coal units is comparable to the gas units being backed down.

5.5.3 Summary of Fuel Scenarios

The higher gas price cases discussed in Sections 5.5.1 and 5.5.2 indicate that above a certain level of divergence in the gas prices paid by the ERCOT utilities, all potential transactions are being obtained, and that the transmission system constraints prevent any further increase. Increases in gas prices result in higher total operating costs and

TABLE 5.5-2

Summary of Annual Generation and Total Savings in 1990:
High Gas Prices

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,024	8,372	442	1,790	1,348	131.1	163.7	10.5	120.7
LCRA	7,858	10,805	265	3,212	2,947	175.6	246.8	17.9	157.6
CPSB	13,227	11,355	2,314	442	-1,872	291.6	215.0	17.1	274.5
HL&P	56,165	76,300	76	20,211	20,135	1,309.4	1,790.4	106.3	1,203.0
TUEC	94,338	71,416	23,275	353	-22,922	2,140.1	1,330.7	124.7	2,015.4
C&SW	24,052	24,416	1,346	1,710	364	575.4	591.9	8.1	567.3
Total	202,664	202,664	27,718	27,718		4,623.2	4,338.5	284.7	4,338.5

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

TABLE 5.5-3

Fuel Consumption in 1995:
High Gas Prices
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
Own-Load Operation						
COA	30,683	37,623	0	0	23,791	92,096
LCRA	22,407	80,139	0	0	0	102,545
CPSB	28,195	106,971	0	0	41,178	176,343
HL&P	245,454	142,698	182,058	0	45,843	616,053
TUEC	360,319	39,352	554,156	348	127,508	1,081,683
C&SW	156,558	92,738	0	39	37,507	286,841
Total	843,614	499,520	736,214	387	275,826	2,355,562
Pool Operation						
COA	33,048	38,759	0	0	23,803	95,610
LCRA	40,328	81,572	0	0	0	121,900
CPSB	26,790	124,144	0	0	41,655	192,590
HL&P	392,323	152,046	180,826	0	45,820	771,017
TUEC	179,402	27,728	574,022	396	128,382	909,929
C&SW	144,755	88,811	0	8	37,489	271,063
Total	816,647	513,061	754,848	403	277,149	2,362,109

TABLE 5.5-4

Summary of Annual Generation and Total Savings in 1995:
High Gas Prices

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	9,210	9,556	811	1,157	346	266.1	276.2	13.9	252.2
LCRA	10,209	12,106	421	2,318	1,897	328.6	399.4	21.8	306.8
CPSB	16,953	18,614	598	2,259	1,661	495.1	535.8	27.5	467.6
HL&P	61,780	77,050	716	15,986	15,270	1,955.4	2,552.6	132.3	1,823.1
TUEC	114,333	96,793	19,073	1,533	-17,540	3,815.7	2,767.8	173.5	3,642.2
C&SW	28,705	27,071	2,911	1,277	-1,634	1,056.4	990.5	26.1	1,030.2
Total	241,190	241,190	24,529	24,529		7,917.3	7,522.2	395.1	7,522.2

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

artificially inflate the dollar value of annual cost savings from pool operations without changing the potential level of transactions. Similarly, the total BTU required to produce the required energy is nearly constant, but gas usage is displaced by higher utilization of coal plants.

At the opposite end of the gas price spectrum, as shown in the converging gas price case where all the utilities are assumed to face the same low price, a different situation exists. As the price falls and the inter-utility price differential is eliminated, the only potential for transactions is a result of the demand/supply relationships and relative efficiencies of the natural gas plants in operation, and the maximum potential transactions fall by approximately 50% compared to the diverging gas price reference case or any cases with higher gas prices. However, after reaching this level, further reductions in the level of gas prices may slightly reduce the level of transactions, but causes the disproportionately lower potential level of savings to remain essentially constant. This conclusion is the same as shown in the earlier version of this report when an artificially low gas price of $2.10/MMBTU was assumed and savings were approximately $52 million. In the current converging gas price case, the price is assumed to be $2.46/MMBTU as recommended by ERCOT and savings are some $56 million. Thus, if a price 15% lower were used, the potential savings only fall by 7%. The highly non-linear relationship between gas prices, transactions, and savings is apparent at both ends of the gas price and differential spectrum.

5.6 Cogeneration Scenarios

Two cogeneration cases have been developed in order to examine a limited set of price and reliability issues. The primary focus of these cases is to examine how cogeneration impacts fuel consumption by ERCOT utilities, under both own-load and pool operations.

In the earlier version of this report, two extreme cases of No Cogeneration and High Load-High Cogeneration were reported. The first of these is quite unrealistic and, with the change in the forecast used in the reference cases, the second case is equally implausible. Both have been dropped. Further analysis of the Alternative-to-Cogeneration case has shown that without the ability to include capital costs and fixed O&M costs, the results using only fuel displacement and variable operating costs can be very misleading and confusing. This case, too, has been dropped.

A list of the cogeneration contracts which are included in the reference case is provided in Table 4.4-1. The two cases which examine the cogeneration fuel displacement issue are constructed by adding or subtracting 15% of the reference case cogeneration and are described below.

5.6.1 1990 Low Cogeneration

This scenario examines the fuel displacement issue in 1990 when the level of cogeneration is assumed to be 15% lower than in the diverging gas price reference case. The distribution of fuel consumption for own-load and pool operation is shown in Table 5.6-1 while transactions levels and variable operating costs are shown in Table 5.6-2. The change in utility and total fuel usage is shown in Figure 5.6-1. Comparable reference case information can be found in Tables 4.2-11 and 4.2-1 and Figure 4.2-11.

When the lower amount of cogeneration is assumed in the own-load operation mode, only HL&P and TUEC are affected since they are the only utilities contracting for cogenerated energy. They replace the loss of the cogenerated energy by increasing their use of conventional generating capacity. HL&P increases its use of gas, coal, and lignite by 4.1%, 1.7%, and 2.0%, respectively, for a total BTU increase of 3.0%. Comparable

TABLE 5.6-1

Fuel Consumption in 1990:
Low Cogeneration
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
Own-Load Operation						
COA	15,128	33,813	0	0	23,529	72,470
LCRA	22,109	56,048	0	0	0	78,157
CPSB	39,132	57,023	0	0	40,532	136,687
HL&P	268,156	91,155	94,596	0	45,460	499,367
TUEC	415,814	0	410,737	226	128,469	955,245
C&SW	123,024	80,343	0	12	37,503	240,882
Total	883,363	318,382	505,333	238	275,493	1,982,809
Pool Operation						
COA	26,547	38,040	0	0	23,803	88,390
LCRA	44,775	64,738	0	0	0	109,513
CPSB	16,683	59,047	0	0	41,655	117,385
HL&P	429,497	128,250	97,108	0	45,820	700,675
TUEC	184,535	0	415,626	226	128,477	728,864
C&SW	125,865	77,079	0	8	37,489	240,441
Total	827,903	367,154	512,734	233	277,244	1,985,268

TABLE 5.6-2

Summary of Annual Generation and Total Savings in 1990:
Low Cogeneration

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,024	8,577	411	1,965	1,554	127.7	164.1	9.2	118.5
LCRA	7,858	11,004	217	3,363	3,146	170.9	241.6	15.9	155.0
CPSB	13,227	11,354	2,224	351	-1,873	279.4	212.8	13.2	266.2
HL&P	56,165	76,265	69	20,169	20,100	1,244.9	1,692.5	90.8	1,154.1
TUEC	94,338	71,503	23,166	330	-22,836	2,022.8	1,287.8	106.2	1,916.5
C&SW	24,052	23,961	1,585	1,494	-91	550.0	555.3	6.1	543.9
Total	202,664	202,664	27,671	27,671		4,395.7	4,154.2	241.5	4,154.2

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

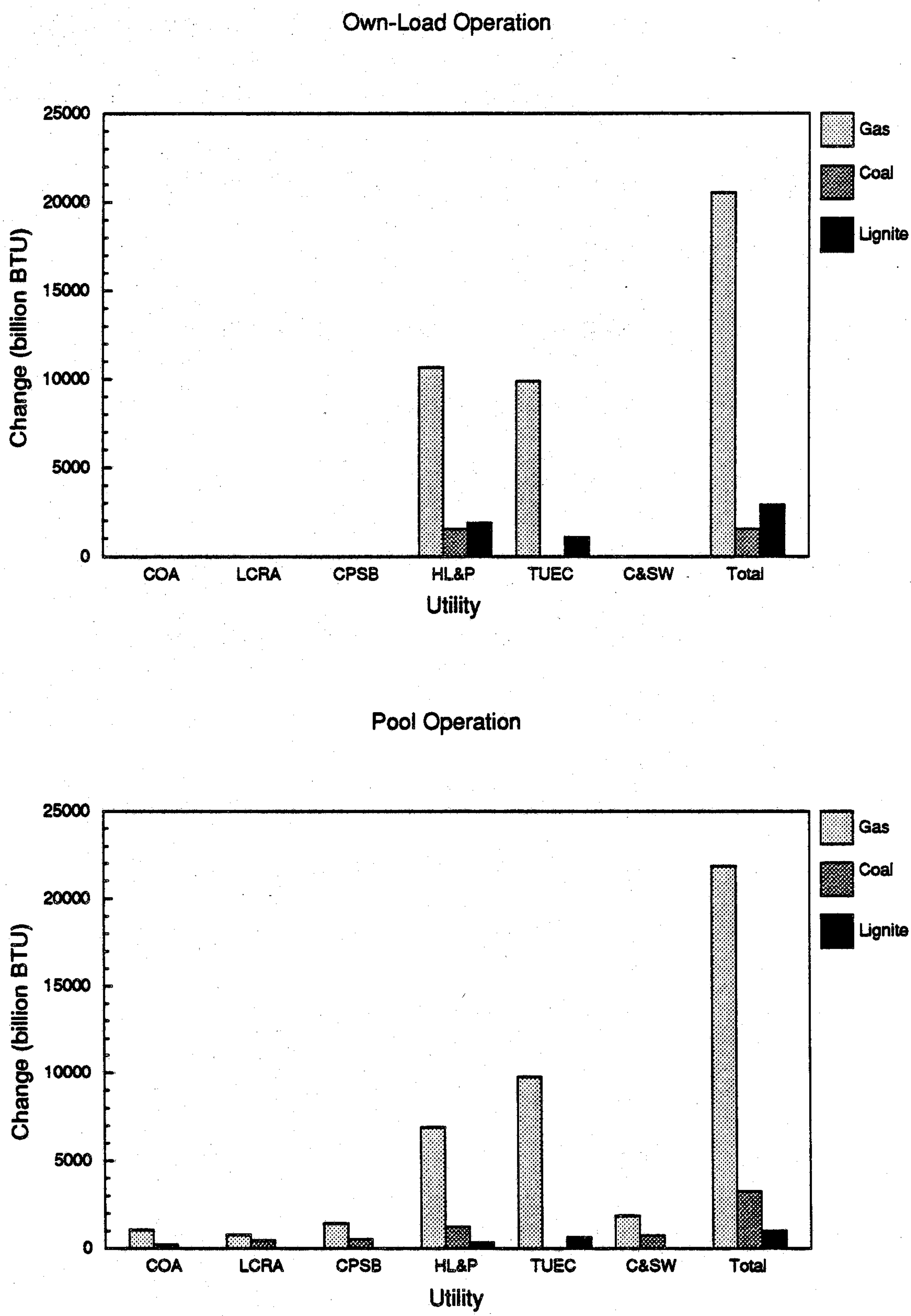


Figure 5.6-1 Change in Fuel Consumption in 1990:
Low Cogeneration

increases for TUEC are 2.4% for gas, 0.3% for lignite, and a total BTU increase of 1.2%. At the ERCOT system level this represents an increase in total BTU of only 1.3%.

When pool operations are assumed, the total BTU consumption also increases by 1.3%, however, all of the utilities experience an increase in gas, coal, and lignite usage with HL&P and TUEC contributing the largest amounts to the increase, particularly for gas.

Because of the small degree of change in fuel consumption, the level of transactions and annual savings change by a negligible amount. Since most of the cogeneration is located in the Houston area, and TUEC is importing from that area, the level of transactions declines slightly, thereby reducing savings by 2.3%.

5.6.2 1990 High Cogeneration

This scenario examines the fuel displacement issue in 1990 when the level of cogeneration is assumed to be 15% greater than in the diverging gas price reference case. The distribution of fuel consumption for own-load and pool operation is shown in Table 5.6-3 while transactions levels and variable operating costs are shown in Table 5.6-4. the change in utility and total fuel usage is shown in Figure 5.6-2. Comparable reference case information can be found in Tables 4.2-11 and 4.2-1 and Figure 4.2-11.

When the higher amount of cogeneration is assumed in the own-load operation mode, again only HL&P and TUEC are affected since they are the only utilities contracting for cogenerated energy. They absorb the increase in cogenerated energy by decreasing their use of other generating capacity. HL&P reduces its use of gas, coal, lignite, and nuclear by 3.9%, 1.6%, 2.2%, and 1.1%, respectively, for a total BTU decrease of 2.9%. Comparable reductions for TUEC are 2.3% for gas, 0.3% for lignite, and a total BTU

TABLE 5.6-3

Fuel Consumption in 1990:
High Cogeneration
(billion BTU)

	Gas	Coal	Lignite	Oil	Nuclear	Total
<u>Own-Load Operation</u>						
COA	15,128	33,813	0	0	23,529	72,470
LCRA	22,109	56,048	0	0	0	78,157
CPSB	39,132	57,023	0	0	40,532	136,687
HL&P	247,486	88,216	90,600	0	44,627	470,929
TUEC	396,508	0	408,596	226	128,445	933,775
C&SW	123,024	80,343	0	12	37,503	240,882
Total	843,387	315,443	499,196	238	274,636	1,932,900
<u>Pool Operation</u>						
COA	23,336	37,537	0	0	23,799	84,672
LCRA	42,975	63,667	0	0	0	106,641
CPSB	13,574	57,908	0	0	41,648	113,130
HL&P	412,689	125,305	96,400	0	45,813	680,207
TUEC	172,889	0	414,072	226	128,443	715,631
C&SW	119,598	75,570	0	8	37,483	232,659
Total	785,059	359,986	510,472	233	277,187	1,932,939

TABLE 5.6-4

Summary of Annual Generation and Total Savings in 1990:
High Cogeneration

	Generation (million KWH)					Operating Cost* ($ million)			
	Own-Load	Pool	Total Purchases	Total Sales	Net Sales	Own-Load	Pool	Savings†	Adjusted Cost
COA	7,024	8,216	486	1,679	1,193	127.7	154.8	8.4	119.3
LCRA	7,858	10,702	297	3,141	2,844	170.9	235.1	15.0	155.9
CPSB	13,227	10,943	2,546	261	-2,285	279.4	200.7	14.8	264.6
HL&P	56,165	77,333	41	21,209	21,168	1,268.3	1,732.0	96.8	1,171.6
TUEC	94,338	72,305	22,408	375	-22,033	2,005.5	1,297.2	105.9	1,899.6
C&SW	24,052	23,166	2,017	1,131	-886	550.0	534.3	6.8	543.2
Total	202,664	202,664	27,795	27,795		4,401.8	4,154.1	247.7	4,154.1

*Cost includes only fuel and variable O&M.
†The method of calculating the savings allocation is discussed in Appendix A.

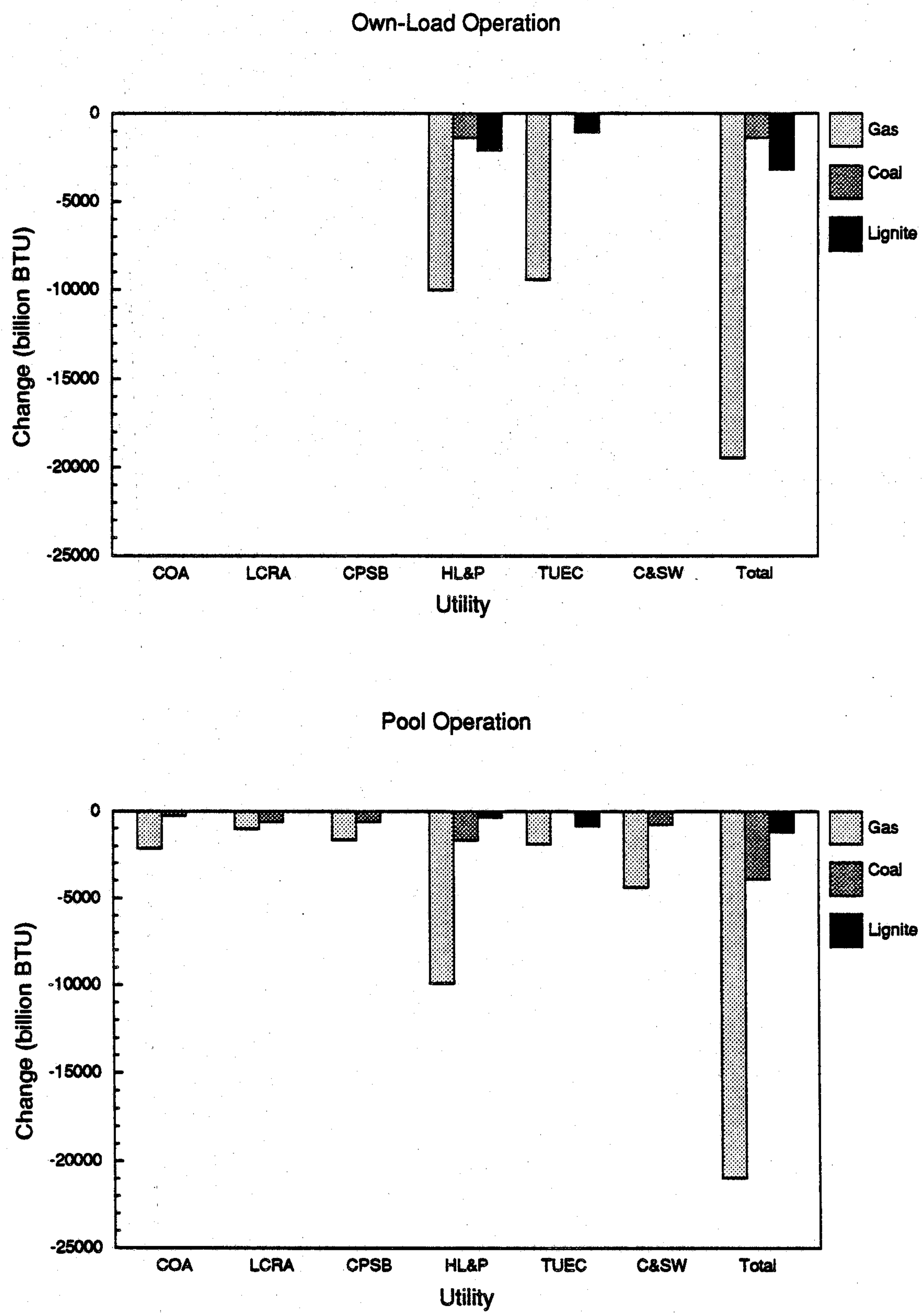


Figure 5.6-2 Change in Fuel Consumption in 1990: High Cogeneration

decrease of 1.1%. At the ERCOT system level this represents a decrease in total BTU of only 1.3%.

When pool operations are assumed, the total BTU consumption also decreases by 1.3%, however, all of the utilities experience a decrease in gas, coal, lignite, or nuclear usage with HL&P and TUEC experiencing the largest reductions, particularly for gas.

Because of the small degree of change in fuel consumption, the level of transactions and annual savings change by a negligible amount. Since most of the cogeneration is located in the Houston area, and TUEC is importing from that area, the level of transactions declines slightly, thereby increasing savings by 0.2%.

5.6.3 1990 Total Fuel Displacement

The total fuel displacement attributable to cogeneration as shown in Figures 5.6-1 and 5.6-2 are short-term results. In both high and low cogeneration cases, the most affected fuel is natural gas. By keeping the level of conventional capacity unchanged, the utilities are assumed to react to the variation of cogeneration capacity by adjusting the output of their own capacity. Because coal and lignite are utilized as base load units, they are fully utilized and can be increased only slightly to compensate for the reduction of cogeneration in the low cogeneration scenario. In the high cogeneration scenario, natural gas, being a more expensive fuel, is backed down first. In the long run, however, cogeneration is expected to displace more coal and lignite and less natural gas.

By combining the results for the low and high cogeneration scenarios, the total fuel displacement attributable can be approximated. The variation in available cogeneration capacity from the low to the high case is 30% of the reference case level of 3,135 MW, or 940 MW. When this variation occurs, with pooled operation, total BTU consumption decreases by 52,329 billion BTU, or 55.669 billion BTU for each MW of cogeneration. Multiplying this by the reference case level of 3,135 MW yields a total displacement of 174.5 trillion BTU, which is distributed as 143.1 trillion BTU of gas, 23.9 trillion BTU of coal, and 7.5 trillion BTU of lignite. These savings only represent the fuel savings as calculated by the model, and do not address the heat rate differential discussed in Section 3.4.

The large quantity of displaced natural gas indicates that the uncertainty of cogeneration has a great impact on natural gas consumption. As the two largest purchasers of cogenerated power, TUEC and HL&P are affected the most. Under pool operation, the displaced fuels are distributed over the four remaining utilities as well.

5.6.3 Summary of Cogeneration Scenarios

The results obtained from the alternate cases indicate that cogeneration provides a significant contribution in fuel savings for the electric utility industry in Texas. The cost savings depend largely on the contract negotiations and the quantity of cogenerated energy purchased by the utilities. Due to the limited pricing information and lack of technical data, the true savings from cogeneration cannot be calculated. Recognizing that cogeneration is more efficient than conventional generation, the cluster of potential cogeneration in HL&P service area may lead to "efficiency differentials" between HL&P and other utilities. With increased system coordination, benefits from cogeneration can be extended beyond HL&P to other utilities as shown in the results for pool operations.

The variation of 940 MW of cogeneration from the low to the high case increases annual savings by approximately $6.2 million, thus the total savings which can be attributed to cogeneration is about $20.7 million for 1990.

5.7 Winter Supply Disruption

The purpose of this analysis is to examine weather conditions that existed during the freeze of December 1983 and predict the impact of such an event on the electric power system as configured in 1990. During this period of prolonged cold weather in 1983, gas suppliers were unable to meet demand, and deliveries to utilities were curtailed. A host of operational problems were also encountered in both gas-fired and solid fuel power stations which may be attributed to the cold weather.

Cold weather can impact the fuel supply of solid fuel plants. At low temperatures, rail transport can be interrupted by derailments due to low rail ductility and snow accumulation on the tracks. However, interruption of coal transport to the plant site will probably not affect plant operations, since a stockpile of 60 days supply is usually maintained. At the plant site, low temperatures may produce frozen masses of fuel that can stop operation of the fuel handling equipment. Problems associated with instrumentation and control lines, fans, and condensers can also arise.

Some of the problems observed during the cold weather of December 1983 which led to forced outages or deratings of solid fuel generating stations include:

(1) frozen reclaim belts; cannot reclaim coal from pile

(2) ice tripping pulverizing mill feeders

(3) low lube oil pressure on pulverizing mills

(4) loss of boiler controls due to freezing

(5) frozen demineralizer lines; reduced ability to supply makeup water to boiler; causes silica buildup in boiler water

(6) frozen soot blowers; causes increase in precipitator temperature

(7) coal train derailment; not expected to impact operations

(8) electrical circuit supplying engine block heaters tripped, bulldozers too cold to start; cannot reclaim coal from pile

(9) frozen exhaust hood spray

(10) condensers plugged with ice

(11) failure of revolving screens on condenser intake due to ice

(12) frozen turbine spray valve

(13) ice on fan blades

Fuel availability and the operation of natural gas-fired generating units can also be affected by low temperatures. Under conditions of low ambient temperature, the temperature drop associated with the expansion of gas in valves can cause the water vapor and heavy hydrocarbons present in natural gas to freeze and plug the valve. This phenomenon was observed during the last two weeks of December 1983 and resulted in a reduction of deliveries to natural gas-fired generating stations as well as operational problems at plant sites. Utilities responded by burning No. 2 fuel oil in combustion turbines and No. 6 fuel in boilers which were normally natural gas-fired. Some problems were encountered during this switch in fuel supply. In addition, operational problems such as the freezing of instrumentation and control lines increased forced outage rates at natural gas-fired plants.

Aside from gas curtailments, other operational problems at gas-fired plants included:

(1) steam line from gas boiler to fuel oil tanks frozen; cannot establish oil circulation

(2) frozen gas valve at plant

(3) plant trip due to high furnace pressure indication; pressure sensing line frozen

(4) loss of some gas-fired cogenerators

(5) frozen air supply lines to air-operated controls

Operational problems encountered during December 1983 led some utilities to revise operating procedures and redesign equipment. Some of the steps taken by utilities in order to mitigate the effects of cold weather on both solid fuel and gas-fired plants were as follows:

(1) addition of a diesel spray header which sprays arriving coal with a fine mist to alleviate icing on fuel handling systems

(2) installation of thermostat-controlled electric heating blankets on chutework

(3) additional heat tracing and insulation in critical areas

(4) reevaluation of fuel oil inventory policies; increase inventory and expand storage capability where needed

(5) place fuel oil system in recirculation mode and steam atomizing system into service whenever cold weather is predicted

(6) install drains on steam lines to fuel oil system so that condensate may be drained

(7) construction of gas storage facilities

Considering the above modifications, it is likely that the ERCOT utilities are better prepared for a cold weather event such as the December 1983 freeze. However, unanticipated problems may still arise. Two issues are addressed in this examination of the impact of cold weather on the ERCOT system.

The first issue is whether or not gas curtailments will limit the generating capability of ERCOT. Some light can be shed on this issue by examining the current fuel oil storage policies of ERCOT members relative to fuel oil consumption during December 1983. As of December 31, 1986, ERCOT utilities had approximately 12 million barrels (grades 2 through 6) of fuel oil stored at plant sites. Assuming an average density of 7.5 lb/gal and average heat content of .019 MMBTU/lb, this fuel oil could provide approximately 72 million MMBTU of energy (12,000,000 bbl × 42 gal/bbl × 7.5 lb/gal × .019 MMBTU/lb = 71,820,000 MMBTU). The above analysis does not account for the capability of ERCOT utilities to stockpile more fuel oil in anticipation of an extended period of low temperatures, and the capability of fuel oil resupply.

It is instructive to compare this fuel oil reserve with ERCOT's current natural gas consumption as well as the ERCOT consumption of fuel oil in December 1983. With respect to current ERCOT natural gas consumption, in January 1986 the ERCOT utilities consumed an average of approximately 32 million MMBTU/day. Comparison with the 72 million MMBTU reserve indicates that ERCOT utilities could accommodate a 100% natural gas curtailment for two days with fuel oil stored on site. Less severe natural gas curtailments could be accommodated for longer periods.

With respect to consumption during December 1983, the ERCOT utilities consumed the following amounts of fuel oil:

UTILITY	FUEL OIL (BBL)
COA (estimated)	100,000
CP&L	114,010
CPSB	117,272
Dallas Power & Light (now in TUEC)	431,468
HL&P	155,047
LCRA	125,413
Texas Electric Service Co. (now in TUEC)	367,470
Texas Power & Light (now in TUEC)	428,747
WTU	100,310
TOTAL:	1,939,737

These data indicate that the ERCOT fuel oil reserves of 12 million barrels, although small by comparison to gas usage, are quite large by comparison to the gas curtailments of December 1983. ERCOT utilities have fuel oil stored on site in sufficient quantities to accommodate gas curtailments six times as severe as those encountered in December 1983.

The second issue is whether or not maintenance schedules are sufficiently coordinated within ERCOT to allow the system to meet demand in the event of extreme cold weather.

The 1990 reference cases scenario indicates that 9,160 MW of capacity will be down for maintenance during the third and fourth weeks of January. This maintenance schedule reduces available generation capacity from 50,804 MW to 41,644 MW. Peak load during this period is forecasted to be 28,059 MW for normal weather. These data indicate that the ERCOT system generation capacity in January 1990 will exceed normal load by 48%. The ERCOT system in 1990 could accommodate a cold weather event under which the combined effects of increased load and increased forced outages did not exceed this margin.

This brief analysis suggests that the ERCOT system in 1990 will be capable of meeting load under adverse weather conditions similar to those experienced in December 1983. In view of the potential consequences of severe gas curtailments in the state of Texas, a more detailed study is warranted. More sophisticated analytical tools are available for the analysis and management of such events.[1,2]

5.8 DC Interconnection to Adjacent Power Pools

Currently, the one point of interconnection that exists between the Southwest Power Pool (SPP) and ERCOT is at the Oklaunion power plant. This 200 MW, back-to-back, direct current intertie is a result of a 1981 settlement among the PUCT, several ERCOT and SPP utilities, the U.S. Department of Justice (DOJ), the U.S. Securities and Exchange Commission (SEC), and the Federal Energy Regulatory Commission. The SEC had requested that Central and South West Services Corporation (C&SW) enter into a show cause procedure regarding its two ERCOT operating companies (CP&L and WTU), and

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[1] A. Charnes, et. al., **Emergency Government Interventions: Case Study of Natural Gas Shortages**, Management Science, Vol 32, No. 10, October 1986, pp 1242-1258.

[2] Peter A. Morris, et. al., A **Utility Inventory Fuel Model**, Operation Research, Vol 35, No. 2, March-April 1987, pp 169-184.

its other two affiliate companies (SWEPCO and PSO) which were not engaged in interconnected operations. Further complications arose as a result of an attempt by WTU to serve some electrical load located just across the Red River in Oklahoma. This attempted connection initially resulted in litigation between ERCOT utilities and C&SW.

A part of the original study design was the evaluation of the potential for establishing DC ties to the other two reliability councils which operate in parts of Texas -- the Southwest Power Pool (SPP) and Western Systems Coordinating Council (WSCC). The purpose of the evaluation was to determine whether there is any potential for energy or cost savings associated with power and energy sales between these reliability councils and ERCOT. It should be clearly noted that such savings could exist whether the individual ERCOT utilities were buyers, sellers, or some combination of the two.

In September, 1986, a Request for Proposal (RFP) was issued to obtain a technical consultant to conduct an analysis of the feasibility of locating DC tie points and lines and estimate the cost of constructing them. The information expected to be gleaned from the study would permit the study staff to identify bus locations which could be treated (in the context of the model) as if they were generating units capable of providing power with associated fixed and variable costs. The contract was awarded to GE in December, 1986; however, after some consideration of their position as a domestic supplier of high voltage DC equipment and the possibility of accusations of interest conflicts, GE withdrew from the contract after giving written notice on February 12, 1987.

After considering the available options, the project staff decided to attempt to complete the analysis based on information that was requested from several adjoining utilities in late March 1987 and possibly enlisting the part-time assistance of a qualified consultant to perform an "over-the-shoulder" review. In addition, new questions were raised by some ERCOT utilities and by the Commission concerning the very complicated legal issues raised with respect to the problem of jurisdictional conflicts with the Federal Energy Regulatory Commission (FERC). On May 12, 1987, a request to research this area was sent to the General Counsel of the Commission. After several months of research, the General Counsel sent a lengthy advisory opinion to the study staff which is reproduced in Appendix F. The conclusion of this advisory opinion states: *Interconnections between ERCOT utilities and other utilities that operate in other states or are otherwise subject to FERC jurisdiction could cause ERCOT utilities engaged in transmission of electric energy or wholesale sales of electric energy to become subject to federal regulation, unless the connections were made in compliance with an order issued under 16 U.S.C. 824i-824k. Because ERCOT operates as a power pool, interconnections would subject all utilities, except those that do not engage in bulk transmission or wholesale sales of electric energy, to federal regulation, including rate regulation.*

Although the staff received some information from three non-ERCOT utilities, it varied considerably in specificity and did not provide all of the cost data necessary to complete the technical modelling, thus the staff was unable to develop a reasonable technical scenario that would not require assumptions which could prove to be untenable for the time periods encompassed by this study.

In view of the legal issues raised and the difficulty of constructing an accurate technical analysis, the study staff does not believe that any additional research effort should address this subject unless institutional circumstances are substantially changed.

Chapter 6
Environmental and Health Issues

The scenarios presented in Chapters 4 and 5 indicate the potential for increased bulk power transactions through increased coordination and information on the ERCOT system, although the MAPS/MWFLOW model does not separate these into firm (uninterruptible) versus non-firm (interruptible) transactions. However, these power flows are presumed to occur within a system configuration and capacity that has been developed and planned to meet reliability criteria that did not then account for their presence. Consequently, in general, when single contingency outage conditions are imposed, the potential level of transactions falls by approximately 30 percent. This can be thought of as representing an interruption of non-firm energy, or as an actual outage caused by overstraining the existing system in the case of firm power and energy.

Thus, it now seems reasonable to anticipate that some additional transmission line construction would be necessary, over and above those projects currently planned, to support higher and more economical level of transactions and retain the excellent reliability which ERCOT has provided.

Construction of new transmission lines, however, has become increasingly controversial during the past several years as higher voltages have become necessary and feasible. Such facilities generally require large metal towers and wider rights-of-way, often leading to the necessity of exercising the power of eminent domain for land or easement acquisition by condemnation procedures. These procedures are usually quite unpleasant for both property owners and utilities because of their adversarial nature. The climate created by such proceedings tends to carry over into considerations of other factors such as health and environmental issues.

In recent years, serious questions have been raised about the potential health or environmental consequences of major transmission facilities. Because these highly sensitive issues are topics of research throughout the world and are also regulated by some states in the U.S., a survey of state requirements was conducted and several current studies were obtained and reviewed.

The following sections of this chapter discuss the evolution of these issues, the current standards and practices of other states, and the implications for the state of Texas and the ERCOT system. Detailed survey results are presented in Appendix D.

6.1 Evolution of the issues

Before the mid-1960s, the issues most frequently associated with transmission line construction and operation were those of conductor corona causing radio and television interference, construction problems, and visual impacts. In the late 1960s, audible noise -- both humming and popping sounds, particularly in inclement weather -- became an issue which generated considerable controversy, particularly because of its subjective nature. Research led to standards which have been generally accepted, although relatively few states seem to have codified them.

In the early 1970s, seemingly prompted by the advent of more 765 kilovolt (KV) lines, the issue of audible noise re-emerged briefly along with some controversy over ozone production by conductors. These issues were surpassed, however, by research results from the U.S.S.R. which purported to show potential health impacts for high-voltage substation workers and led to the electric field effects conundrum. Press articles and one non-technical book appeared which escalated the issue into sharper public view. A few research papers claimed to show biological effects on small animals. The utility industry began to respond by citing other studies which showed no effects. In the midst of conflicting claims, it became apparent that good research was needed which would take advantage of the expertise of utility engineers, physicists and biological scientists.

Inter-disciplinary studies began under the auspices of a few individual utilities, the Electric Power Research Institute (EPRI), and the U.S. Department of Energy through its Inter-agency Advisory Committee on Biological Effects. Many of these early studies attempted to identify the presence of "significant" adverse biological effects associated with induced electric fields. Here the term "significant" is used in its statistical sense in conjunction with the acceptance or rejection of a null hypothesis of effect presence or absence, as opposed to the more common understandings implying serious, major, or profound. This misunderstanding has certainly confused the debate about potential effects.

Since the late-1970s, research has continued using methodologies from the disciplines of epidemiology, toxicology, and risk assessment, as well as the classical medical and biological sciences and engineering. Some of the studies of electrical fields have produced quantifiable results such as perception threshold and "let-go" levels for induced currents in grounded objects. These limits have formed the basis for standards such as the National Electric Safety Code (NESC) 5 milliampere maximum current level for a short-circuit from objects beneath power lines to ground.

The research into the presence or absence of more subtle effects has continued to produce a wide array of contradictory and controversial results, due in part to the scientific methodology which inherently precludes any definitive conclusion that there are no effects. A scientific advisory panel commissioned by the state of Florida concluded in 1986, after reviewing nearly 400 studies, that it is unlikely that human exposure to 60 Hz electric fields of the intensity associated with transmission lines can lead to public health problems. The Bonneville Power Administration (BPA) in its annual review of electric field effects for 1986 cites some 20 additional research efforts with comprehensive reviews of the literature which have drawn similar conclusions.

Very recently, the focus of attention has shifted from electric fields to magnetic fields as a study commissioned by the New York Power Lines Project has indicated some potential association between the configuration of the electrical distribution network in residential areas and the incidence of childhood cancers. A similar study in a different locale showed no such association for adults. Other studies have shown that magnetic fields can be detected by some insects and animals; that some magnetic fields can affect nerve cell functions; and that there are measurable effects within other cells and tissues. But these in vitro studies have not concluded that there are any practical problems where the tests so far have not indicated any pathological problems from the exposure. Most, if not all, of the studies for both electric and magnetic field effects contain less than conclusive results along with recommendations for more research.

6.2 Survey Results

In March, 1987 a request was sent to the utility regulatory authorities in 49 states and the District of Columbia requesting information pertaining to their standards or considerations for health and environmental concerns related to transmission lines. 35 states (including Texas) responded with information that ranged from simple declarations of no standards to hundreds of pages describing their entire review and certification process. Most of the information submitted dealt with environmental and siting issues. Health issues were generally not discussed, although there are six states which have now adopted maximum electric field standards and a few others which have set requirements in individual cases.

Detailed survey results can be found in Appendix D, while discussion of the environmental and health standards appears later in this chapter.

6.2.1 Principal Agencies and General Requirements

In most of the reporting states, the Public Utility Commission or its equivalent has some responsibility for siting and standards for transmission line construction. In many states, one or more other state departments such as Environmental Protection, Natural Resources, Energy, and Health or their equivalents have some concurrent authority.

Some states have created special Facility Siting groups which may be cabinet level officials, special appointees, members of the public or some combination thereof. These siting boards may have concurrent or exclusive jurisdiction, and broad ranging powers to approve, modify, or deny routes for transmission lines.

The primary regulatory mechanism continues to be the certification process, although a few states impose the additional requirement of a formal environmental impact statement, or its equivalent. Many states require the filing of environmental information with the application for a certificate of convenience and necessity and review each application on a case-by-case basis. A few states have formal standards for design or construction which each line must meet to be considered for approval.

6.2.2 Minimum Voltage Applicability

There is a substantial variation in the minimum voltage of lines which must have prior approval before construction. A few states report no minimum, while the lowest numerical standard was 700 volts for some special cases in Nebraska and the highest reported was 400 KV in Kentucky. Although some states have multiple standards based on line length, the distribution of reported standards are as shown below.

0	to	68	KV	--	3	states
69	to	137	KV	--	11	states
138	to	344	KV	--	10	states
345	or	more	KV	--	1	state

6.2.3 Environmental Requirements and Considerations

Of the 35 states responding to the survey, 22 indicated some type of consideration of environmental factors as part of the transmission line siting or certification process. There was again substantial variation among these states with some requiring only that unspecified "environmental or ecological factors" be noted while others such as Washington require the submission of a full Environmental Impact Statement with substantial documentation and analysis. Few of the states reported any directly measurable standards other than by reference to compliance with applicable laws and regulation of the federal Environmental Protection Agency (EPA). Oregon, for example, sets a maximum allowable sound level of 50 decibels at the edge of the right-of-way for transmission lines.

Again, most of the states consider these factors on a case-by-case basis which likely develops precedents to be used on subsequent similar cases. The following list of factors which may be considered is intended to be representative, though not exhaustive, of the types of information which may be required or reviewed.

<u>Location maps of corridors of varying widths</u>

alternative routes investigated

topographical features

geological features

public roads and lands

incorporated communities

structures

airports

lakes, rivers, and other watercourses

land uses

Identification of unique features

parks and recreational areas

historic sites

archaeological sites

scenic sites or areas

flood plains

national and state forests

access roads or areas

natural or mineral resources

shoreline areas

Identification of biological features

domestic animals

wildlife management areas

land and aquatic habitats and migration routes

vegetation and proposed controls

rare or endangered species

Assessments or evaluations

air quality

water quality

audible noise

soils and erosion

seismic potential

electric fields

magnetic fields

communications interference

visual impact

comparison to "no-build"

mitigation strategies

Other relevant factors

costs and financing

engineering design and features

socio-economic impacts

cultural or community values

other governmental entities

effects on energy cost

electric system reliability

interconnections

transportation

6.2.4 Health Requirements and Considerations

Although the question of the possibility of adverse human health effects associated with electromagnetic field effects has been under scrutiny for several years, the level of uncertainty associated with available research seems to be reflected in the responses to the survey. Of the states who responded, only two (Minnesota and Oregon) have adopted regulations concerning field effects. (Information for the four other states which have adopted standards was obtained from other sources.) A few other states indicated that some standard had been proposed in singular cases, but not adopted as a statewide standard. Several states have opted for a "wait-and-see" policy of requiring an annual review of emerging research and monitoring the issue as it develops.

Although there was no specific mention in many states' replies, it appears that most regard the requirements of the NESC with respect to induced current and nuisance shocks as an adequate minimum standard. Florida, in addition, is currently in the process of developing and proposing other requirements for field effects. Michigan has adopted a very detailed construction code which specifies requirements for lines with as low as 700 volts of capacity.

6.2.4.1 Minnesota Standards

As a result of the hearings associated with the development of a 500 KV line in 1976, the Minnesota Environmental Quality Board -- based on testimony from only one expert witness -- adopted a maximum allowable field strength of 8 KV/m. This applies anywhere on the proposed right-of-way at a height of 1 meter above ground level. In its findings the Board determined that this standard would protect the public health.

6.2.4.2 Montana Standards

As a condition for certification of a proposed double circuit 500 KV line, the Montana Board of Conservation and Natural Resources -- based on a literature review done in 1983 by a consultant -- adopted as a "public health criterion" a maximum field strength of

1 KV/m at the edge of the transmission right-of-way at the height of 1 meter above ground level in residential or subdivided areas. In addition, however, the Board permits the standard to be waived by the owner of each parcel of land from whom an easement is obtained. A second standard was adopted for road crossings where the maximum field strength allowed is 7 KV/m on the right-of-way at a height of 1 meter.

6.2.4.3 <u>New Jersey Standards</u>

In 1981, a joint standard was adopted by the Commission on Radiation Protection and the Department of Environmental Protection limiting the field strength to 3 KV/m at the edge of the right-of-way (presumably at a height of 1 meter), but the standard is only used for evaluating complaints about existing lines. Neither agency has regulatory authority for siting decisions, hence the standard is advisory only.

6.2.4.4 <u>New York Standards</u>

In 1973 and 1974, the New York Public Service Commission received applications for certification of more than 200 miles of 765 KV lines from various utilities. Because of the interest in the health and biological effects, common record hearings were held to avoid lengthy duplication. More than 30 witnesses testified and produced over 14,000 pages of testimony and exhibits -- most of which addressed the electric and magnetic field issues. In 1978, the Board decided that it could not ignore some inferences of risk raised in the record. As a result, the Board took two actions: one established the New York Power Lines Research Project; while the other, as a precautionary measure, set an interim standard based on the existing fields associated with 345 KV lines.

The interim standard was established at 1.6 KV/m at the edge of the right-of-way (presumably, 1 meter above ground level) and a moratorium on constructing any lines which would exceed this standard was declared. Enforcement of the standard was accomplished by specifying a minimum clearance distance for residences of 175 feet from the centerline of a 765 KV line. In 1978, the interim standard was extended to all future transmission lines using calculated field strength intensities. In addition, in order to limit the short-circuit-to-ground current to 4.5 mA, electric field maximum limits of 7, 11, and 11.8 KV/m (at ground level) were set for public roads, private roads, and other terrain, respectively.

The Research project has funded several laboratory and epidemiological studies and is currently evaluating results of recent studies of field effects and childhood cancer. There appears to be some shift in focus from the electric to the magnetic field effects, and a committee has been formed to determine whether magnetic field standards should be adopted and, if so, at what levels.

6.2.4.5 North Dakota Standards

On the basis of testimony from seven expert witnesses from hearing on four projects (three 345 KV and one 500 KV), the Public Service Commission has informally set a 9 KV/m maximum electric field strength, even though a staff report stated that it found no credible evidence of biological effects associated with high voltage transmission lines.

6.2.4.6 Oregon Standards

The Energy Facility Siting Council has established as a public health standard a maximum electric field of 9 KV/m in all areas to which the public has access. In order to be certified, all transmission lines must be designed to meet this criteria.

6.3 Summary and Conclusions

The health and environmental issues surrounding the construction and operation of high voltage transmission lines have become increasingly controversial throughout the nation. In recent years, this has been no less true in the state of Texas where in one case, based at least in part on assertions of potential health effects on school children, a jury trial in a condemnation case in a county civil court at law resulted in a judgment against the location of a 345 KV line and an award of monetary damages in excess of $25 million against the utility for "abuse of Discretion." Although the jury did not find that the line constituted any health risk to any person, and the exemplary damages has since been reversed by a higher court, the utility applied for and received certification and constructed an alternate routing of that segment of the line in order to maintain service during the pendency of appeals. As a result of this and other issues, a task force has been established by the Commission to review all aspects of current transmission certification policies.

With respect to other states responding to the survey, it appears that Texas' requirements for examining potential environmental factors and impacts are about average. Some states are certainly more stringent, but many have much weaker or non-existent standards. The information required for applying for a certificate falls within several quite general categories -- some of which are rather amorphous such as "community values". If additional lines become necessary to support bulk power transactions and maintain ERCOT system reliability as suggested in other parts of this report, the development of more specific or operational definitions would provide more understandable guidelines for utilities to follow.

With respect to other states' requirements for the minimum size lines that require certification procedures, it appears that the Texas limit of 60 KV is among the very lowest in the country. If this limit were raised or if lower voltage lines could be handled administratively, many utilities could save time and expense, while the staff would be able to concentrate more time and effort on larger lines where controversy is expected to persist.

With respect to health standards, Texas is typical in its requirement that all facilities meet the provisions of the NESC with respect to design, engineering, and construction practices. However, it is unquestionably true that the controversy over electromagnetic fields and their possible biological effects exists today and is not likely to be resolved in the immediate future. A possible solution to this dilemma would be to adopt a policy similar to those in several other states which provides for timely monitoring of the literature and an annual report which summarizes the results and recommends courses of action. Such a review could be conducted by the staff in cooperation with selected representatives of the State's utilities.

6.4 Selected References and Literature Reviews

As indicated throughout this chapter, the amount of information pertaining to environmental standards and health issues is quite extensive. The following citation of existing reviews which themselves have lengthy lists of references and bibliographies provides a reasonable overview of particularly the biological effects issue. For detailed information concerning environmental regulations, the respective states should be contacted.

(1) **High Voltage Transmission Line Electric and Magnetic Fields: Emerging Research and Regulatory Issues**; Robert S. Banks and Robert I. Kavet; 18th Annual Transmission and Substation Design Symposium; University of Texas at Arlington, Office of Continuing Education; September 18-20, 1985

(2) **Electrical and Biological Effects of Transmission Lines: A Review**; Bonneville Power Administration, Portland, Oregon; Revised edition of June, 1986

(3) **Biological Effects of 60 Hz Power Transmission Lines**; Florida Electric and Magnetic Fields Science Advisory Commission, Department of Environmental Regulation, Tallahassee, Florida; March, 1985

(4) **International Utility Symposium, Health Effects of Electric and Magnetic Fields: Research, Communication, Regulation**; Electric Power Research Institute, et al; September 16-19, 1986