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A Methodology to Identify Stranded Generation Facilities and Estimate Stranded Costs for Louisiana's Electric Utility Industry.

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A METHODOLOGY TO IDENTIFY STRANDED GENERATION FACILITIES AND ESTIMATE STRANDED COSTS FOR LOUISIANA'S ELECTRIC UTILITY INDUSTRY

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If people do not believe
that mathematics is simple,
it is only because they do not realize
how complicated life is.

- John von Neumann

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ABSTRACT

The electric utility industry in the United States is currently experiencing a new and different type of growing pain. It is the pain of having to restructure itself into a competitive business. Many industry experts are trying to explain how the nation as a whole, as well as individual states, will implement restructuring and handle its numerous "transition problems."

One significant transition problem for federal and state regulators rests with determining a utility's stranded costs. Stranded generation facilities are assets which would be uneconomic in a competitive environment or costs for assets whose regulated book value is greater than market value. At issue is the methodology which will be used to estimate stranded costs. The two primary methods are known as "Top-Down" and "Bottom-Up." The "Top-Down" approach simply determines the present value of the losses in revenue as the market price for electricity changes over a period of time into the future. The problem with this approach is that it does not take into account technical issues associated with the generation and wheeling of electricity. The "Bottom-Up" approach computes the present value of specific strandable generation facilities and compares the resulting valuations with their historical costs. It is regarded as a detailed and difficult, but more precise, approach to identifying stranded assets and their associated costs.

This dissertation develops a "Bottom-Up" quantitative, optimization-based approach to electric power wheeling within the state of Louisiana. It optimally evaluates all production capabilities and coordinates the movement of bulk power through transmission interconnections of competing companies in and around the state. Sensitivity analysis to this approach is performed by varying seasonal consumer demand, electric power imports, and transmission interconnection cost parameters. Generation facility economic dispatch and transmission interconnection bulk power transfers, specific to each set of parameters, lead to the identification of stranded generation facilities. Stranded costs of non-dispatched and uneconomically dispatched generation facilities can then be estimated to indicate, arguably, the largest portion of restructuring transition costs as the industry is transformed from its present monopolistic structure to a competitive one.

CHAPTER 1

INTRODUCTION

1.1 History of the Industry

The electric power industry of the United States is undergoing a revolutionary transition from vertically integrated and regulated run monopolies to fully competitive unbundled industries of generation, transmission, and distribution. State legislatures and regulatory agencies throughout the country are struggling with the challenges of restructuring. Industrial customers, as well as residential and commercial customers are questioning current regulatory practices and the monopolistic structure of electric utilities and are either advocating or rejecting proposals for significant change.

A historical view of the electric utility industry in the United States reveals three significant periods. The year 1973 serves as the dividing point for the first two periods. Before 1973 the industry was characterized by steady growth. Many large baseload steam generation plants were built, technology advances were routine, fuel prices were relatively stable, and electricity demand grew and was expected to continue in the immediate future. Regulatory policies were predictable during the early period. In addition, generation production planning focused on economies of scale, and competition within the industry did not exist.

After 1973, the industry entered a second period that was much more turbulent and less predictable. The energy crisis of the middle to late 1970's and early 1980's sent energy prices soaring. As a result, growth in demand for electricity fell sharply. Few technological advances were made during this period. The main steam generation advancement pertained to nuclear power and it was far overshadowed by the many accident-related setbacks that occurred during its development.

A major change in the industry occurred when federal regulatory policy shifted to compensate for the energy crisis. The shift resulted from the enactment of the National Energy Act of 1978. This Act was composed of five statutes:

(1) Public Utilities Regulatory Policy Act (PURPA),
(2) National Energy Tax Act,
(3) National Energy Conservation Policy Act,
(4) Power Plant and Industrial Fuels Act (PPIFA), and
(5) Natural Gas Policy Act.

The National Energy Act of 1978 was intended to ensure continued economic growth during a period in which both the availability and the price of future energy resources were in jeopardy. The two important themes backed by this piece of legislation were:

(1) to promote conservation and the use of other energy sources, and
(2) to reduce the country's dependence on foreign oil.

While all statutes of the National Energy Act affected the electric power industry, PURPA and PPIFA affected it in the most significant manner. PURPA was designed to encourage

a more efficient use of energy through the cogeneration of electric power. PURPA required existing electric utility companies to interconnect and purchase power from any non-utility qualifying facility (QF) at a rate not to exceed the connecting electric utility's avoided cost of generation. This new mandate was quite different from traditional monopolistic cost-of-service regulation where prices are set at an electric utility's cost of production. Under PURPA, prices are still set at the local utility's cost of production, not the QF's cost.

While PURPA encouraged cogeneration, PPIFA limited the number of economically feasible generation fuel options available to an electric utility by prohibiting them from constructing any new steam baseload generation facilities which were fueled primarily by oil or natural gas. Natural gas was still available for intermediate, peaking, and cogeneration facilities, but only coal and nuclear fuels could be used for baseload generation facilities.

One could argue that electric utility deregulation began with the enactment of PURPA and PPIFA. Together they initiated a new power market where established electric utility generation facilities coexist with cogeneration facilities. These two pieces of legislation were the foundation for competition within the electric utility industry. Since the enactment of the National Energy Act of 1978, the non-utility share of total electricity generation facilities in the United States has more than doubled

(Dismukes et al., 1996a). The third period began with the enactment of the National Energy Policy Act of 1992.

1.2 The Energy Policy Act of 1992

In October of 1992, the United States Congress passed a National Energy Policy Act (Public Law 102-486). The Act added momentum towards competition initially started by PURPA and PPIFA. It provided for the generation of electric energy by independent power producers for wholesale or retail sale. This piece of legislation encourages non-utility power production by creating a new category of electricity providers known as exempt wholesale generators (EWGs). These EWGs differ from QFs in two distinctive ways:

(1) they are not required to meet PURPA's cogeneration or renewable fuels limitations, and
(2) utilities are not required to purchase power from EWGs.

In addition, the National Energy Policy Act of 1992 allows the Federal Energy Regulatory Commission (FERC) to order electric utilities to provide access on their transmission systems for EWGs. Specifically, Subtitle B - Federal Power Act; Interstate Commerce in Electricity, Section 721, part (1) reads as follows:

> Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale or resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant.

This was a significant step toward deregulation. The situation which now exists between electric utilities and

EWGs is commonly known as "wholesale wheeling". Wholesale wheeling allows many non-generating utilities to "shop around" for cheap electric power and effectively reduce their historical dependence on electric power generated by their local electric utility.

1.3 Importance of Wheeling to Restructuring

Wheeling is defined as the transmission of electricity by an entity that does not own or directly use the power it is transmitting (IEEE PES, 1996). A transmission network plays a strategically important role in electric power wheeling. By providing the critical connection between neighboring markets, it enhances the geographical scope of the power system.

The United States electric power system is characterized by a high degree of interconnection and diverse ownership of transmission assets and generation resources. The implementation of wheeling in the United States hinges upon the establishment of property rights, adequate infrastructure capacity, usage protocols for transmission networks, and mechanisms for compensation and usage charges.

There are two major risks associated with wheeling. First, there is economic risk. Fundamentally, it is the failure of a competitive electric power supply market to develop. If this were to occur, it is possible that competition would not replace regulation in assuring that consumers are protected from unfair pricing strategies.

Second, there is operational risk. This is simply the risk of not delivering electric power to customers, and, in turn, compromising the reliability and integrity of a transmission system as well as its distribution system. What is important about operational risk is that the failure to deliver electric power to individual customers will affect all customers through congestion and inadequate infrastructure. Therefore, if deregulation of the electric utility industry is to be successful under both risks, wheeling must first be successful. For wheeling to be successful, a complete infrastructure evaluation must be performed prior to each electric power trade.

1.4 Economic Impact of Restructuring the Industry

Some industry experts argue that substantial improvements in the United States aggregate economy are highly probable once the electric power industry is restructured. They note that restructuring the industry can reverse the productivity slowdown that has plagued the aggregate economy in the last quarter century. Also expected are improvements in Gross Domestic Product (GDP), the Producer Price Index (PPI), and employment.

In a study by Moroney (1990) of the cross sectional relation between output per worker and capital and energy intensity in a sample of market and centrally planned economies, the elasticity of output per worker to energy intensity ranged from 0.15 to 0.19. Maloney et al. (1996a) use this figure in another study to project a short run

increase in electricity use by a minimum of 13.4% to a long-run increase of as much as 42.4%. By using this projected increase of electricity use and Moroney's elasticity of output per worker to energy intensity, Maloney et al. estimate an increase in GDP between 0.8% and 2.6%. In 1995 the GDP totaled $7,340.4 billion. Using these estimates, the increase in GDP is expected to be between $60.7 billion and $190.85 billion. Maloney et al. conclude that this significant increase in the nation's GDP would be attributed to electric utility deregulation.

Electricity is also an intermediate good that influences prices of many consumer goods. The Producer Price Index (PPI) is a measure of such intermediate goods. In 1995, 5.37% of the PPI accounted for prices of electric power. Again, using the estimated reduction of electricity prices of 13.4% to 42.4% , resulting from a unit elastic increase in consumption, and keeping the prices of all other producer commodities constant, Maloney et al. (1996a) indicate that competition in the electric power industry will cause the PPI to decrease by 0.7% to 2.3%.

Employment is expected to increase because of the increase in GDP. During the final month of 1995, 121.2 million people were employed. The figures above indicate an increase in overall employment of 1.0% to 3.15% (Maloney et al., 1996a).

1.5 Stranded Investments

The term *stranded investment* refers to the cost of existing equipment or facilities that are no longer needed after one or more customers stop buying power from the local utility and instead choose to purchase power from outside sources (IEEE PES, 1996). With widespread competition, a utility will use its own electric power generation mix of investments to compete for market share with other suppliers. A problem for an electric utility surfaces if its rates exceed market clearing prices for electric power. The utility will then reduce its rates in expectation of retaining its market share. These price reductions will reduce its revenues. If revenue from the sale of electric power is less than the total cost of production, then certain generation facility investments a utility has made in the past are considered uneconomical. It is the forces of:

(1) the loss of revenue needed to cover costs, and
(2) the existence of uneconomical generation facilities[1]

that explain why utilities are concerned that some existing generation facility investments may become stranded.

1.6 Economic Impact of Stranded Investments

For decades, regulators gave electric utilities an incentive to overbuild. "Gold Plating" capital additions was the strategy utilities followed to earn more profit (Murphy and Soyster, 1983). Through the decades of regulation, electric utility companies have been allowed a certain

percentage profit on their assets, so the more assets they could accumulate, the better. More importantly, policy makers allowed rate increases in the past to recover the cost of those investments. If some of the investments are not completely amortized and become stranded, a question arises as to who should be obligated to pay for them. Additionally, determining which stranded investments are fully depreciated and which are not can turn out to be a difficult task as electric utility companies begin to classify their deregulated financial information as proprietary. For these reasons, the identification of stranded investments is of major concern to policy makers.

Estimates of aggregate stranded costs vary greatly, ranging from a low of $10 to $20 billion to a high of $500 billion depending on the assumptions used to estimate them (DOE/EIA-0562, 1996). McKinsey & Company estimates the value of unnecessary nationwide electric generating plants to be at about $150 billion (Business Week, 12/2/96). The American Public Power Association claims that about 5% to 10% of the capacity assets of investor-owned electric utilities may become stranded. In addition, there are groups who believe that a large portion of stranded costs may be attributable to nuclear power plants. According to one study from the Department of Energy, of the nearly $120 billion in undepreciated assets in domestic nuclear power plants, nearly $70 billion may be stranded in a competitive environment (Yokell et al., 1995).

Louisiana rate payers "own" two nuclear power plants and have a contractual interest in a third. These plants are River Bend and Waterford 3, of Entergy Gulf States, Inc., and Entergy Louisiana, Inc., respectively and Grand Gulf of System Energy Resources, Inc.

The major stumbling block for regulators will be whether they allow for the recovery of the large sunk costs they approved in prior years. Economist Paul L. Joskow favors making quick decisions on fixed or sunk costs and then moving on since there is no perfect solution anyway. "Only God knows what the right way of allocating sunk costs is," states Joskow (Business Week, 12/2/96). The important decision for regulators will be whether rate payers, capital investors, taxpayers or any combination of all three groups should pay for sunk costs.

1.7 "Top-Down" vs. "Bottom-Up" Estimation Methods

It has been widely accepted that the composition of stranded costs will be dominated by assets related to a utility's generating capacity. The valuation of these assets can be determined by two basic approaches. The first approach computes the present value of strandable assets and compares the resulting valuation with their historical costs (DOE/EIA-0562, 1996). The second approach computes the loss in revenue as the market price for electricity changes over a period of time into the future, determines its present value, and classifies the amount as stranded costs (DOE/EIA-0562, 1996). The first method is generally considered a

"Bottom-Up" approach and the second is known as a "Top-Down" approach. The "Bottom-Up" approach computes the amount of each investment that would be stranded. The "Top-Down" approach calculates the difference in revenues under a regulatory regime and those likely to accrue with the beginning of competition.

The Federal Energy Regulatory Commission (FERC) has adopted the "Top-Down" approach in hopes of avoiding asset-by-asset reviews to calculate recoverable stranded costs. By adopting this approach, FERC is trying to avoid including other items of costs that would likely be added into "Bottom-Up" stranded cost calculations. These items could include any of the following: fuel supply costs, purchased power contracts, nuclear decommissioning costs and/or the cost of other social and environmental programs. Even though FERC has adopted this method, it is up to the individual state regulatory authorities as to whether they will adopt it. The "Top-Down" approach for estimating the Stranded Cost Obligation (SCO) of a departing generation customer from an electric utility takes the following form:

$$SCO = (RSR - CMVE) * L, \tag{1.1}$$

where,

RSR = Revenue Stream estimate attributable to the departing customer based on the average of three prior years' Revenues,

CMVE = Competitive Market Value Estimate either from sale of released capacity or the average annual cost to the customer of replacement capacity and associated energy, and

L = Length of time of obligation (DOE/EIA-0562, 1996).

Obtaining an estimate of CMVE in the above equation makes the "Top-Down" approach quite difficult since it is strictly based on market analysis. In addition, the "Top-Down" lost revenues approach rewards higher priced electric utility companies having high RSR's.

A detailed and difficult, but more precise, method for estimating stranded costs would be a "Bottom-Up" approach that determines exactly which generation facilities are needed to meet demand and which are expected to be stranded. Even though other categories of additional stranded costs might surface, the evaluation of efficient, inefficient, and idled generation facilities is pertinent.

It is worth noting that a firm may or may not incur stranded costs through "Bottom-Up" analysis because of transmission system constraints and/or market clearing prices. The stranded cost question is more accurately answered by valuing the generation asset portfolio of each company under economic dispatching conditions. The valuation process is not simple, but can be handled through technical and economic methods. First, on the technical side, transmission assets and power flow paths need to be accounted for to ensure the movement of bulk power from all generation facilities in the portfolio to respective sources of demand. This is accomplished through the use of basic engineering circuit analysis. Second, on the economic side, typical regulation practices do not allow firms to charge

prices that reflect the economic value of their assets, leaving the true method of economic dispatch in question. Marginal prices are needed for a true measure of economic dispatch but are generally considered to be proprietary information for any particular generation facility. There are measures to estimate marginal prices, and that topic will be addressed in the next chapter.

In addition, there is no reward for regulated firms to operate productive assets with no book value since there is no capital recovery. Thus, regulated firms have historically had an incentive to idle generation facilities that are still economical to operate and would continue to be valuable in a competitive market (Maloney et al., 1996b). In an unregulated market many of these generation facilities would produce net positive cash flows, and it is still unclear whether they would be used in estimating lost revenues for stranded cost recovery through the "Top-Down" approach.

1.8 Other Deregulated Industries

Deregulation has already occurred in the natural gas, airline, long-distance telecommunications, railroad, and trucking industries. Political agendas, some ending with legislation, lead the way in all cases and are currently paving the way again for deregulation in the electric utility industry. It should be possible to use the experience of regulatory reform of the other industries to guide the electric utility industry. The specific acts of

legislation used for deregulation for each industry are listed below in Table 1.1.

TABLE 1.1
PREVIOUS DEREGULATION LEGISLATIVE ACTS

INDUSTRY	LEGISLATIVE ACT AND YEAR
Natural Gas	FERC Order 436, 1985
Airline	Airline Deregulation Act, 1978
Long Distance Telecommunications	AT&T Divestiture, 1984
Railroad	Staggers Act, 1980
Trucking	Motor Carrier Act, 1980

The following subsections discuss how each deregulated industry relates to the electric utility industry, its deregulation process and stranded cost recovery figures (where they exist). Industry experts have claimed successful economic results by deregulating each of the industries. Each industry's success demonstrates that deregulation can be a positive step for the electric utility industry.

1.8.1 Natural Gas

Like the electric utility industry, the natural gas industry includes competitive producers who transport their product through a network. Pipelines, like transmission grids (neglecting electrical loop flow characteristics), can be thought of as a tank of fluid that various parties alternately fill and draw from. A gas shipper is similar to a person who pours an agreed-upon amount of fluid into the

tank and the buyer as one who draws an agreed-upon amount out. Interestingly, the buyer does not necessarily receive the exact molecules of fluid the shipper put in. The transmission of electricity can be thought of in the same oversimplified example (Ellig, 1994).

To deregulate, FERC Orders 436 and 500 transformed interstate pipelines from integrated gas merchants into providers of gas transportation. Pipelines may still participate in the merchant and gas sales business through affiliated companies, but the pipeline transmission function is now a separate entity with its own set of financial accounts. Opponents of open access to gas transmission expressed fears that separating the merchant from the transportation function would reduce the reliability of the pipeline system, but no problems have been exposed so far (INGAA, 1996). The electric utility transmission system may possess some of its own unique technological challenges, but the gas industry's experience suggests that open access systems may be more reliable than many people previously thought.

The natural gas industry's issue of restructuring costs was completed using a two-step process. First, the industry went through a period called the "Take-or-Pay Era" (1988-1993). *Take-or-pay* liabilities that pipelines incurred were defined as contractual obligations for minimum quantities of gas from producers at prices that could not be recovered in the increasingly competitive gas supply market.

Pipelines settled some of their take-or-pay obligations with producers through cash payments and contract reformation (INGAA, 1996). Next, the "Transition Costs Era" (1993-1996) occurred. Under FERC Order 636 issued in 1992, customers and pipelines were required to reform any remaining bundled sales contracts into transportation contracts. The general method of recovering gas supply realignment costs was a fixed surcharge for all transportation customers (INGAA, 1996).

The natural gas industry incurred $13.2 billion in restructuring costs as a result of regulatory changes (INGAA, 1996). One early gas restructuring cost estimate by FERC Order No. 500-H. F.R. 52344 (1989) was for $44 billion. Of the gas industry restructuring costs to date, pipelines have absorbed 28 percent, or $3.7 billion (INGAA, 1996).

There are several lessons to be learned from the natural gas industry's experience with restructuring costs that may be relevant to electric utility industry policy makers. First, pipelines had to adopt open access and provide their customers with choices before their stranded costs liabilities were settled (INGAA, 1996). Second, pipelines had powerful incentives to hold restructuring costs down because they were not allowed to recover restructuring costs fully through FERC policies and open access competitive pressures (INGAA, 1996). As a result, stranded costs in the natural gas industry turned out to be significantly less than expected.

1.8.2 Airline

Airlines and electric utilities share some interesting similarities. For instance, privately-owned airlines are similar to independent power producers since they can serve customers in a wide variety of areas. But, to carry out their service, airlines are dependent upon government-owned air traffic control systems and airports. By comparison to electric utility functions, these are the airline's "dispatchers" and "transmission lines" (Ellig, 1994). Service in this industry was never bundled as it was in the natural gas industry or still is in the electric utility industry.

Before 1978, airlines were subject to both maximum and minimum fares established by the Civil Aeronautics Board. The Board also controlled entry to individual city-pair routes. Regulation of this industry had the effect of creating a government enforced cartel that artificially raised prices. The Airline Deregulation Act of 1978 deregulated fares and entry into individual routes, which set competition in motion.

Since government controlled the "dispatchers" and "transmission lines" of the airline industry, no real transition costs are known. The best estimate of transition costs stems from the airlines that did not survive deregulation because of inefficient pricing. Shareholders of airlines that went out of business, because of industry shake-out absorbed all transition costs in investment losses

(Edison Electric Institute, 1995). The surviving airlines, unlike independent power producers, had no real threat of stranded costs. They could simply purchase/lease larger or smaller aircraft to fit any specific market.

1.8.3 Long-Distance Telecommunications

Similar to the electric utility industry, telecommunications involves the transportation of electrons over wires (Ellig, 1994). Currently, local telephone companies are economically similar to local electric utility companies. Local phone companies enjoy being monopolies on the sale of local phone service and on the transportation of long distance calls from the originator to the long distance carrier and from the long distance carrier to the receiver.

Competition in long-distance telecommunications service occurred in stages. In the late 1950's, the Federal Communications Commission began to permit competition in private microwave service. In the late 1960's and early 1970's, federal regulators permitted competition in private-line common carriage. MCI opened the door to competition in 1974 when it began offering switched-voice message service, the same ordinary long distance service that accounted for more than 90 percent of AT&T's long distance revenues (Crandall and Ellig, 1997). The federal courts refused to uphold the Federal Communications Commission's efforts to relegate MCI to private-line service. This effectively opened the door to long-distance telecommunication competition.[2]

Since there were still local phone company monopolies, the Federal Communications Commission drafted rules designed to ensure that long-distance telecommunications companies would be able to use local phone lines to access customers. Local phone companies were required by the 1982 Consent Decree to provide open access under equal and nondiscriminatory terms to competitive long-distance carriers (Dismukes et al., 1996b).

Stranded costs associated with the transformation of the long-distance telecommunications industry were entirely absorbed by the shareholders of AT&T. The losses were a direct result of the break-up of the Bell System. In 1983, the company recorded a $5.5 billion dollar extraordinary charge to income (Moody's, 1983). This loss represented over 10 percent of AT&T's total equity (Moody's, 1983). The change resulted from overvaluation of a significant amount of AT&T's installed equipment investments under traditional rate of return regulation. These excessive costs were not recoverable in a competitive market, so AT&T's shareholders were required to absorb 100 percent of the excessive investments (Dismukes et al., 1996b).

The long-distance telecommunications example illustrates that regulators can separate local exchange facilities from other sectors of industry without destroying service reliability. Local telephone companies simply use their equipment to route long-distance calls and then collect access fees for doing so.

1.8.4 Trucking

Trucking companies are similar to independent power producers in that they do not own the highways they must use to serve their customers. Like airlines, trucking companies use government-owned highways that are open to all users. These highways are analogous to transmission and distribution lines owned by electric utilities (Ellig, 1994).

Trucking deregulation occurred with the Motor Carrier Act of 1980. Prior to this piece of legislation, the Interstate Commerce Commission rigidly controlled entry into the trucking industry. Rate changes by truckers had to be approved by the Commission as well as by competing carriers. To bypass this problem, many large firms found it profitable to acquire their own trucking fleets. These fleets were profitable at the expense of being inefficient. Since they could not carry another company's goods for hire, they often cruised empty on the return trip, wasting fuel, time, and money. The Motor Carrier Act of 1980 changed this situation by expediting entry and permitting truckers to set rates on their own initiative.

The insight drawn from the trucking industry is similar to the one drawn from the airline industry. Inefficient pricing strategies heavily influenced the shake-out of the industry. Therefore, pricing for electric utility generation, transmission, and distribution assets should reflect marginal principles. The prices need not be optimal

since optimal pricing in the real world is often difficult to determine, but incorporating marginal principles is a step in the right direction (Crandall and Ellig, 1997).

1.8.5 Railroads

In an economic sense, a railroad is similar to an investor-owned electric utility firm with only generation and transmission facilities. The railroad's generation capacity is its locomotives and freight cars, and its transmission capacity is its track. But, unlike airlines and trucking companies, railroads own and maintain their assets (Ellig, 1994).

During the 1970's, federal regulation had bankrupted several railroads because of intensified competition from trucking firms. The root of the bankruptcy problem stemmed from the "value of service pricing" policy mandated by the Interstate Commerce Commission (Crandall and Ellig, 1997). This policy forced railroads to charge higher rates on "high-value" shipments of goods. These were the same goods that trucking firms were best suited to handle.

The Staggers Act of 1980 deregulated the industry and ended inefficient federal railroad policy. However, the Interstate Commerce Commission still does have the power to regulate rates charged to captive shippers, but 90 percent of all rail traffic rates are fully deregulated (Crandall and Ellig, 1997). In some cases the Interstate Commerce Commission can require a railroad to permit a competitor to use its track and facilities. In this case the foreign

company's train is treated like any other train on the host's track. Some railroads even voluntarily permit foreign companies to run trains over their tracks. The argument for doing this is if one company can operate a train less expensively than the company owning the track, both companies have a profit incentive to negotiate open access (Crandall and Ellig, 1997). The end result is transportation at a lower cost, which can increase profit for both companies.

In each of the above mentioned industries, critics argued that deregulation would not work because of special characteristics inherent to each industry. Others argued that it may have been true that these characteristics caused problems at first, but once these were overcome most, if not all, consumer groups were better off because of deregulation.

1.9 The Dissertation Purpose

This country's electricity system is characterized by a diverse ownership of generation facilities and a high degree of interconnection. Unlimited transmission interconnection capacity would imply an extremely large market for electric power, while limited transmission interconnection capacity would imply a limited area for competition where local generation might be one's only source for electric power.

Transmission interconnections are very important when it comes to taking advantage of regional power generation

cost differences. If one market has a very large cost advantage over another, the transmission paths connecting those markets will become congested with flows from the low-cost market to the high-cost market. Even though the National Energy Policy Act of 1992 mandates that transmission system access will not be a problem for EWGs, transmission system infrastructure cannot be updated overnight.

A problem arises in deciding which generation facilities must be committed or idled and when such scheduling should occur. With such a diverse and large supply of generation resources in the United States, the idling of some generation facilities will be unavoidable when scheduling to fulfill demand requirements. It is the identification of stranded generation facilities that is of interest to policy makers.

The purpose of this dissertation is to empirically evaluate the supply of electric power generation and transmission interconnection capacity for wheeling power in and around the state of Louisiana. The goal is to determine which electric power generation facilities need to be committed to meet the state's peak electricity needs while taking into consideration capacity constraints created by limited transmission interconnections.

To determine the optimal commitment of generation facilities in Louisiana, the dissertation presents an electric power production and bulk power transmission

nonlinear programming optimization model. The model relaxes intricate power system characteristics such as thermal, voltage and frequency stability limitations and allows for an economic study of bulk power transfers. The model is designed to capture the optimal production and transmission of electric power by company control area during a one-hour peak period of demand.

The state is broken up into its existing investor-owned electric utility control areas, a government-owned electric utility control area, its municipally-owned electric utility control areas, and other electric utility control areas for importing electric power from neighboring states. Given average variable production cost data[3] for each generation facility and peak demand for each control area, the nonlinear programming optimization model characterizes electric power production and bulk power transmission trends on the aggregated electric power system.

Obtaining data for the optimization model can be considered to be a separate research topic all its own. Identifying and collecting average variable production costs for each generation facility is a straightforward but tedious research task.

From the assumption of a coincident one-hour peak demand for electric power, stranded generation facilities can be identified and segregated for the estimation of stranded generation facility costs to consumers, utility companies, or their respective investors.

Transmission system pricing strategies can also be viewed as possible constraining factors for wheeling low-cost power. If a transmission access tariff is high enough, it can restrict the reach of low-cost power generation facilities. Transmission system pricing strategies are not a part of this dissertation, but are left for future research.

1.10 Current Legislation

There are many electric utility restructuring related bills currently in Congress. Several senators and representatives have them in committee ready to be debated during the first session of the 105th Congress. A brief list of bills follows to emphasize the importance of restructuring the nation's electric utility industry.

(1) "*Electric Consumers Protection Act of 1997*"
Senate Bill #237,
by Senator Bumpers of Arkansas

(2) "*Public Utility Holding Company Act of 1997*"
Senate Bill #621,
by Senator D'Amato of New York

(3) "*Consumers Electric Power Act of 1997*"
House Bill #1230,
by Representative DeLay of Texas

(4) "*Electric Power Competition and Consumer Choice Act of 1997*"
House Bill #1960,
by Representative Markey of Massachusetts

(5) "*Electric Consumers' Power to Choose Act of 1997*"
House Bill #655,
by Representative Schaefer of Colorado

(6) "*Electric Utility Restructuring Empowerment and Competitiveness Act of 1997*"
Senate Bill #722,
by Senator Thomas of Wyoming

The one important aspect of all bills is that each state is allowed to determine its own stranded costs. Once these are determined, the state is expected to recover and repay all parties having incurred stranded costs.

1.11 Organization of the Dissertation

The dissertation is presented in seven chapters. Chapter 1 is an introductory chapter which provides a history of the electric utility industry and motivation for the research from the National Energy Policy Act of 1992. Chapter 1 also presents the importance of wheeling to restructuring the industry, the economic impact of restructuring, a discussion of stranded costs, its economic impact and valuation, the deregulation of other industries, a statement of the problem with the dissertation purpose, and current legislation pending. The first chapter concludes with an organizational outline of the dissertation.

Chapter 2 introduces previous published and unpublished literature concerning dissertation subject matter. The chapter begins with a discussion of Regulatory Economics where the Averch-Johnson hypothesis is reviewed. The chapter then introduces and critiques existing stranded cost estimation models. Next, electric utility restructuring methods are presented. The Bilateral Contract method, the Poolco method, and a combination of both are discussed. The chapter proceeds by providing an overview of electric power system modeling literature. Specifically, economic dispatch, unit commitment, optimal power flow, the transportation

method for optimal power flow, and multiarea production simulation literature are reviewed. Next, the average cost vs. marginal cost argument is presented in the context of electric power production pricing.

Chapter 3 formulates LaDEUX (**L**ouisian**a**'s **D**eregulated **E**lectric **U**tility **EX**change), an electric power production and bulk power transmission optimization model. It is based on economic dispatch concepts with unit commitment, optimal power flow, and multiarea production simulation characteristics, and is constrained by transmission interconnection capacity. The model is nonlinear in formulation and is constructed to capture optimal generation facility production and bulk transmission of electric power during a one-hour coincident summer and winter peak period of demand. All modeling notation and assumptions are also presented. A simplified example problem is then introduced to illustrate formulation of the model as well as its solution. The chapter proceeds to present a economically designed experimental solution strategy for determining stranded and uneconomically operating generation facilities and their costs. The experimental design is based on average variable and fuel production costs, transmission interconnections and their costs, and summer and winter coincident peak demands.

Chapter 4 introduces two methods of analysis for estimating stranded generation facility costs, each of which is based on the economic dispatch results obtained from the

LaDEUX model. First, the Cost-of-Plant method is presented. It estimates stranded generation facility costs in the strictest form. Next, the Embedded Cost method is presented. This method is an extension of the Cost-of-Plant method that takes into account costs of facilities that are dispatched, but operating uneconomically. Finally, the simple example problem introduced in Chapter 3 is revisited to illustrate each method of stranded generation facility cost analysis.

Chapter 5 discusses all data sources used to produce LaDEUX. The chapter explains how and where all technical and economic data were gathered for model development.

Chapter 6 presents stranded generation facility results from LaDEUX and stranded generation facility costs furnished by the Cost-of-Plant and Embedded Cost methods of estimating stranded cost. Estimating stranded generation facility costs is a two-stage process where the cost analysis performed in the second step of the methodology is dependent upon the dispatch results obtained first from the LaDEUX model.

In the first stage, results of sixteen economic dispatch experiments are presented. Average variable and fuel cost pairs of similar experiments form the ranges for capturing true marginal production cost dispatch. In addition, a market clearing price and market clearing facility are determined for each experiment. General observations and interesting economic dispatch results are also presented.

In the second stage, the economic dispatch of each experimental pair is processed by both cost analysis methods, and the resulting estimates for stranded generation facility costs are given. A stranded cost range is supplied for each experimental pair. This is done in the same fashion as the economic dispatch results presented from the LaDEUX model since true marginal production costs are unknown.

Finally, Chapter 7 furnishes conclusions of the dissertation. Results are summarized and limitations are addressed. It also presents extensions to the methodology for future research for both the LaDEUX model for economic dispatch and the Embedded Cost method for estimating stranded generation facility costs. The chapter concludes by identifying the successes and major contributions of the research.

1.12 End Notes

[1] The terms "uneconomical generation facility" and "uneconomically dispatched generation facility" are intended to represent a generation facility whose marginal production cost and embedded sunk cost is higher than a system's market clearing price for electric power.

[2] See MCI Telecommunications Corp. vs. Federal Communications Commission, 561 F 2d 365 (D.C. Cir. 1977).

[3] Average variable production costs are composed of fuel costs and operation and maintenance costs.

CHAPTER 2

REVIEW OF LITERATURE

2.1 Introduction

The individual literature topics reviewed in this chapter support the development of a modeling methodology employing a "Bottom-Up" approach for evaluating stranded generation facilities. The chapter begins with a review of the Averch-Johnson approach to regulatory economics. It hypothesizes an over-capitalization phenomenon of electric utility assets justifying the existence of stranded generation facilities.

The chapter then introduces and reviews existing models that estimate stranded costs. Electric utility industry restructuring methods are then presented as the basis for formulating a new modeling methodology to assess electric power wheeling and identify stranded generation facilities and subsequently estimate their costs.

Next, technical literature is reviewed to support the formulation of an economic dispatch model. Once presented, literature concerning data for model implementation is discussed. Supply side production costs are reviewed first and average vs. marginal cost data are then discussed in the context of generation facility production costs.

2.2 Averch-Johnson Approach to Regulatory Economics

The Averch-Johnson approach to economic regulation has focused upon the actions of the regulated firm subject to a

regulatory constraint, rather than on actions and behavior of the regulatory body itself. The Averch-Johnson approach assumes that the regulatory body follows a traditional social welfare maximizing role. Since regulators are assumed to be maximizing social welfare, the actions of the regulated firm become the focus of inquiry.

Averch and Johnson (1962) formed a static, deterministic model of the regulated firm subject to a regulatory constraint. The regulatory constraint is merely a cap, set by the regulatory body, on the maximum allowable rate-of-return that the regulated firm can earn. In the model, depreciation is assumed to be zero, and the only cost of acquiring capital is the interest to be paid on plant and equipment.

After formulating this model, Averch and Johnson reached two controversial conclusions. Specifically, they concluded that a regulatory bias exists when the regulated allowed rate-of-return is greater than the cost of capital. This encourages the regulated firm to make inefficient capital-intensive investments. A second, but often overlooked conclusion, is that regulated firms also have the incentive to cross-subsidize less profitable operations at the expense of more profitable operations, so long as the firms' overall rate-of-return remains unchanged. Both of these conclusions provide formal evidence that rate-of-return regulation can impose social costs in the form of input and output inefficiencies and that over-

capitalization can lead to the stranding of inefficient assets.

The initial Averch-Johnson work has been subject to a great deal of criticism and theoretical modifications and additions. The idea that the regulated firm pads its rate base is not new to practitioners of economic regulation, but Berg and Tschirhart (1995) state that academics have an incentive to tweak existing models for a quick publication rather than take the time to develop an understanding of the important issues of the model. The literature begins to feed on itself without getting external reality checks. However, Averch and Johnson were the first to be able to incorporate this idea into a stylized model that has survived the test of time, even though detractors such as Corey (1971) and others have criticized the model's assumptions and have said the model is overly simplistic for applied work.

Empirical tests of the Averch-Johnson approach are varied and reach differing conclusions. Petersen (1975) found that lower rates-of-return were significantly associated with higher costs and large proportions of capital-related costs. In his model, Petersen reformulated the Averch-Johnson hypothesis in terms of cost-minimization subject to the regulatory constraint. It is shown that as the cost of capital approaches the allowed rate-of-return, the regulated firm incurs higher unit costs and spends a larger portion of total cost of capital than otherwise. As

Petersen explains, regulation would be considered to be "tightened" if the allowed rate-of-return and the cost of capital were equated. Other extensive empirical studies presented by both Spann (1974) and Courville (1974) support the over-capitalization hypothesis.

Other studies, however, have failed to support the Averch-Johnson over-capitalization hypothesis. Baron and Taggart (1977) conducted an empirical investigation of the Averch-Johnson hypothesis by forming a financial model of shareholder preferences of input choices for the regulated firm. Instead of focusing upon actual production outcomes, shareholder preferences serve as indicators of over- or under-capitalization. The empirical evidence revealed that an increase in the regulated firm's capital stock results in a shareholder-anticipated reduction in the price of the regulated firm's equity. Thus, in order to maintain shareholder profitability and support, the regulated firm will not choose an input level which is biased towards capital—contrary to the Averch-Johnson conclusions. Boyes (1976) and Smithson (1978), using different empirical models, also failed to find any evidence of over-capitalization.

In hindsight, it is interesting to question the arguments of critics of the Averch-Johnson hypothesis. If Averch-Johnson critics support under-capitalizing assets to maximize shareholder wealth, then why are investor-owned utility companies asking for stranded cost recovery?

To summarize, the Averch-Johnson approach has become accepted as the mainstream, traditional approach to modeling economic regulation. The regulatory constraint, while not escaping criticism, is considered by many as a proper description of how the regulated firm maximizes profit in a regulatory environment. The original apparatus, as presented by Averch and Johnson, has undergone a number of significant modifications and revisions. The empirical evidence, however, has remained mixed—some studies support the over-capitalization hypothesis, others do not. In general, while mainstream, the Averch-Johnson over-capitalization hypothesis takes a technical approach to the study of economic regulation. Regulation is seen merely as an optimization problem rather than an intricate balance of the interactions of numerous economic agents and interests.

2.3 Existing Stranded Cost Models

To date two models have been developed for the estimation of stranded generation costs. Both are versions of the Federal Energy Regulatory Commission's lost revenues, or "Top-Down" approach to stranded cost estimation. One model has been developed and used by the Texas Public Service Commission. The other model was developed by the United States Department of Energy's Oak Ridge National Laboratory. While the Oak Ridge model's intention is to be an electric utility financial and production simulator, it does have the ability to estimate stranded generation facility costs.

A review of each of these models is found below. Each review contains an explanation of model development and a critique of potential results.

2.3.1 ECOM Model of Texas

A need for the Texas Public Utility Commission to investigate the problem of potentially strandable generation facilities emerged. The Texas Commission instituted Project 15001, *Stranded Cost Report: Estimation of ECOM for Generating Utilities in Texas*, to determine the magnitude of generation facility Excess Costs Over Market (ECOM) under various competitive scenarios affecting investor-owned, municipally-owned, and cooperatively-owned electric utilities in the state. Legislative questions concerning proper direction for the industry and pending national competition have contributed to this need.

To determine generation excess costs over market, an electronic workbook using Microsoft Excel version 5.0 software was designed and developed by commission staff. The workbook is called the ECOM Model. The model estimates the after-tax net present value of the change in revenues an electric utility would experience as a result of selling electricity at market prices rather than at regulated prices. It defines generation excess costs over market as the discounted present value of the difference between sunk costs and the contributions to capital of utility sales under competition. The model estimates retail excess costs over market but has the ability to estimate wholesale

excess costs over market as well. It is an obvious "Top-Down" approach.

The model's users input disaggregated capital and production costs associated with generation assets and allocate these costs by resource type and by customer class. Users also allocate projected sales by resource type and by customer class. Using these cost and revenue projections, the model calculates utility revenues under continued cost of service regulation. Next, the Commission provides a range of future market prices—low, base, and high—which is used in the calculation of market-based revenues under alternative competitive scenarios. The model then calculates the excess costs over market of generation assets based on the difference between revenues under cost-of-service regulation and those under competitive scenarios. The model can accommodate any number of additional relevant scenarios.

The ECOM model can be summarized by the following equations:

$$ECOM = dPV[FC - (MP - AVC) * MWh], \tag{2.1A}$$

or

$$ECOM = dPV[FC + TVC - Revenues], \tag{2.1B}$$

where,

dPV	= Discounted Present Value,
FC	= Fixed Costs of Current Assets,
MP	= Market Price of Electricity,
AVC	= Average Variable Costs of Electricity,
MWh	= Sales at the Market Price,
TVC	= AVC * MWh, and

Revenues = MP * MWh.

Although sanctioned by the state, several parties expressed opposing opinions concerning the adoption of ECOM's "Top-Down" approach. In particular, Destec Energy, Texas Ratepayers Organization to Save Energy, the Environmental Defense Fund, the Office of the Public Utility Counsel, Texas Citizens for a Sound Economy Foundation, and Consumers Union expressed reservations about or opposition to the approach. They all argued that the "Top-Down" approach may overstate strandable costs, that the method implicitly assumes an entitlement to full recovery of strandable generation assets, and that it may not be capable of accurately depicting a competitive market.

In contrast, several utility parties, including Texas Utilities Electric Company and Houston Lighting and Power Company, favored the application of the approach. Houston Lighting and Power Company in particular proposed use of a methodology consistent with the "Top-Down" approach used by the Federal Energy Regulatory Commission. It is interesting to note that in Houston Lighting and Power Company's contrasting opinion, it was not mentioned that the company has the highest wholesale and industrial rates in the state and several inefficient generation units (Matlock, 1995). Texas Utilities Electric Company, on the other hand, has higher than average wholesale rates and many inefficient generation units but does have the lowest industrial rates

in the state (Matlock, 1995). This is an example of one of the problems associated with the "Top-Down" approach. Companies that have high rates and inefficient generation units have the ability to fully recover stranded generation costs. In other words, a company can get rewarded for having high rates and being inefficient with production.

It is puzzling to note that in its report, *Staff Discussion of the Order: Estimation of ECOM for Generating Utilities in Texas, 1996*, the commission staff states that it believes

> ". . .the calculation of a *scenarios-based "Lost Revenues" approach* is wholly consistent with the calculation of an asset-by-asset (or a non-scenarios-based) measure of ECOM. Both "Lost Revenues" and asset-by-asset are methods of measuring ECOM. The only difference between these two approaches is that the "Lost Revenue" approach calculates ECOM based on average costs over categories of assets—defined by fuel type—while the asset-by-asset approach is a "Bottom-Up" approach. Under a consistent set of assumptions (e.g., allocating revenues to certain resources or resource types), the two approaches should yield the same ECOM for any scenario."

Since no asset-by-asset approach was conducted by the commission staff, it is difficult to accept these statements indicating that the approaches are similar.

A short-coming of the ECOM model is its inability to take into account simultaneous utility generation of other facilities around the state of Texas and the ERCOT system. It is strictly a utility company-by-utility company approach to determining stranded generation costs. The model implies that customers are displaced by non-utility

generation within a utility company's own control area or artificially wheeled power, but customers can be displaced by neighboring utility generation through transmission system interconnections. The model should be enhanced to perform its calculations on a state/system-wide basis since all ratepayers within the state/system boundaries are likely to pay stranded generation facility costs. The "Bottom-Up" approach used to determine stranded generation costs developed in this dissertation is designed as a state/system-wide approach for the specific identification of stranded generation facilities while constraining the state/system by its transmission system interconnections.

2.3.2 ORFIN Model of Oak Ridge National Laboratory

Oak Ridge National Laboratory is a research facility managed and operated by Lockheed Martin Energy Research Corporation for the United States Department of Energy. It has on staff three principle researchers studying the restructure of the electric utility industry. Eric Hirst, Lester Baxter, and Stan Hadley are the researchers, and their contributions to restructuring literature are numerous.

Oak Ridge Financial Model (ORFIN) described in ORNL/CON-424 (1996) and ORNL/CON-430 (1996) is a finance and operations model used to help analyze the impacts of electric utility restructuring as it pertains to customers, existing utilities, and other stakeholders. The model is a Microsoft Excel version 5.0 workbook, approximately 1.4

Mbytes in size. It uses multiple worksheets to separate the various calculations, input, and output. The worksheets are entitled: Input, Finance, Plants, Dispatch, Charts, Dispatch Macros, and Other Macros. The model combines detailed pricing and financial analysis (an Annual Summary Statement, Income Statement, and Balance Sheet) with an economic dispatch model over a multi-year period and is used to study various types of performance-based rates, stranded commitments recovery, and retail wheeling options. By varying the performance of a modeled electric utility, a user can observe the consequences of various performance-based ratemaking algorithms on prices and profitability. Modeling individual high-cost assets, as well as transmission and distribution assets, and modifying their accounting allow a user to compare different stranded cost recovery methods as well as ways to mitigate impact. The authors of the model indicate that it is a "Bottom-Up" approach to calculating stranded commitments. They argue that since ORFIN dispatches each generating unit and power purchase contract individually it is performing "Bottom-Up" analysis.

It is typically accepted that the costs of a utility are dominated by the cost of the generation facilities and contracts it uses to provide electricity. Because of this, the economic dispatch portion of ORFIN has been modeled in much greater detail than the other financial worksheets. Inputs to the economic dispatch worksheet in ORFIN include

six pre-existing generation facilities, two pre-existing contracts, a new resource (which can be a power plant, contract, or demand side management program), and additional capacity added on a yearly basis to meet minimum reserve margin requirements. Additional, detailed information on the operation and costs of these resources is provided to allow closer representation of actual utilities.

ORFIN incorporates system load duration curves into the economic dispatch worksheet. It uses two curves for each year: an on-peak season curve (where no maintenance is done on plants) and an off-peak season curve (where plants are derated for maintenance outages). An additional technical aspect of the model is its probabilistic-based forced outages of generation facilities. The probabilistic forced outages, generally known as a loss-of-load probability, create an equivalent load duration curve where higher-cost production facilities will see not only demands from customers but also "equivalent demands" based on the probability of lower-cost production facilities undergoing a forced outage.

Also included in the dispatch worksheet is an external wholesale power market with tiered prices based on customer loads. If capacity and/or transmission constraints keep a utility from meeting its customers' requirements, demand is purchased on the wholesale market at a market clearing wholesale power price.

The economic dispatch worksheet uses data for each year to calculate the generation, contract purchases, and wholesale (spot) purchases and sales for the utility. The dispatch worksheet first calculates load-duration curves for a specific utility's on-peak and off-peak seasons. It then sorts the ten generation facilities (including contracts) in order of their variable costs. The production cost results are then used by the financial worksheet to calculate operations and maintenance costs for the utility.

Analysis of stranded commitment costs requires two ORFIN runs. The first run is a base case with no retail wheeling occurring in the utility's control area. The second run includes retail wheeling with the user specifying the timing and amount of wheeling that occurs year by year. The retail wheeling case has retail electricity prices set equal to those in the base case. Differences in annual earnings between the base and retail wheeling cases are the model's estimates of stranded commitment losses that the utility's shareholders would experience. Keeping prices fixed between the base and retail wheeling cases ensures that none of the stranded commitment costs are borne by retail customers in the model. Instead, all stranded commitment costs are born by utility shareholders.

Similar to the problems pointed out in the ECOM Model of Texas, ORFIN also has the inability to take into account simultaneous utility generation of other interconnected

facilities. It is strictly an artificial utility company-by-utility company approach to determining stranded commitments. This model again implies that customers are displaced by non-utility generation within a utility company's own control area or with wheeled power, but customers can be displaced by neighboring utility generation through transmission system interconnections. The model should be expanded to included several companies within an interconnected system or power pool. As stated earlier, the "Bottom-Up" approach used to determine stranded commitments developed in this dissertation is designed as an interconnected system-wide approach for the specific identification of stranded generation facilities, while constraining the system by its transmission system interconnections.

Another problem with the model is the authors' mislabeling of their stranded commitment calculation. The method of computing stranded commitments as defined in the model is the difference in annual earnings between the base and retail wheeling cases. This is really an estimate of stranded earnings and not stranded commitments. The financial statements should be adjusted to calculate the difference in annual production costs between the base and retail wheeling cases. This would amount to an estimate of stranded commitments based on a "Bottom-Up" approach. As long as some form of revenues is involved in the

computation of stranded commitments, stranded profit or stranded earnings will always be determined.

2.4 Electric Utility Industry Restructuring Methods

Many consumer groups and regulatory commissions throughout the country have been investigating different methods of moving toward competition. The essence of electric power competition is that each customer will be able to buy its generation, generation-related services, and ancillary services from a market comprised of many sellers. A customer will no longer be limited to buying these services from his/her local monopolistic electric utility. A customer will, however, still be limited to buying regulated transmission and distribution service from monopolistic providers. The methods of moving to a competitive market most often discussed are:

(1) the Bilateral Contracts method, and
(2) the Poolco method.

Some industry restructuring advocates support a market structure that is completely dependent upon Bilateral Contracts. In this case, the power flows from contracts would be scheduled by the buyers and sellers, and an Independent (transmission) System Operator (ISO) would be needed merely to coordinate all contract flows and reschedule them when conflicts arise (Tellus Institute, 1997).

There are advantages and disadvantages to restructuring using the Bilateral Contract method. One advantage is that buyers are able to exercise negotiating

power by signing contracts of any and all possible durations. A potential disadvantage is introduced if contracts of long duration have contracted prices above the average market price. In this case a customer will end up paying too much for electric power. The reverse of this situation can be seen as an advantage if the average market price stays above the contracted price for the duration of the contract.

Other restructuring advocates support a Poolco (power pool) market structure. In the Poolco market, each supplier would submit bids to the Poolco in specified time increments for electric power the supplier could make available. Generation facilities would be dispatched by the Poolco from lowest to highest bid until total demand in the specified time increment was met. The highest bid generation that was used to meet total demand in the specified time increment would determine a market clearing price. This price would be paid to each and every owner of dispatched generation, regardless of the type of generation facility (i.e., base, intermediate, or peaking load), and regardless of the price at which the generation facility was actually bid. The market clearing price would also be paid by each and every consumer who purchased power from the Poolco, regardless of the type of generation facility (i.e., base, intermediate, or peaking load) that the customer actually needed to meet his load profile (Tellus Institute, 1997).

A controversial advantage of a Poolco system over a Bilateral Contract system is its ability to collapse the contract signing time and the delivery time into the same point in time. The contract terms would be the prices and quantities bid by suppliers into the Poolco. A disadvantage of a Poolco system is its inability to allow a potential buyer the opportunity to "shop around" and play one supplier off of another to negotiate a lower price for power. Without this negotiation tactic, horizontal market power is likely to surface in a Poolco system and raise prices for all buyers.

Finally, there are those who support a more complicated market structure, whereby a Poolco would be established as a competitive short-term energy market (i.e., a spot market), and Bilateral Contracts would be used to lock in to fixed prices for short-, medium-, and long-term power purchases (Tellus Institute, 1997). In this way, a customer could:

(1) sign contracts for power so that he/she would know ahead of time what prices he/she would have to pay (i.e., he/she would be ensured price stability and predictability),

(2) buy power from the Poolco, whereby he/she would have to pay the Poolco's market clearing price in each time period, or

(3) purchase power through a mix of contract purchases and spot market purchases.

To conclude, it is difficult to predict which direction regulators will proceed in restructuring the electric utility industry. Preliminary evidence has

indicated that large industrial customers favor a Bilateral Contract approach since they have large loads for negotiation leverage and small customers favor a Poolco approach since they have no market power for negotiations.

2.5 Electric Power System Modeling

It is necessary to explore literature concerning the evolution of electric power system modeling and the sophistication of solution methods used. The topics reviewed increase in complexity as they are introduced. It is hoped this review will help demonstrate the impossibility, under currently available technology, of formulating and solving a complete interconnected electric utility power system model.

2.5.1 Economic Dispatch

Generation facility dispatch determines the share of load demand that each facility delivers. The purpose of generation facility dispatch is to minimize the total system operating cost for delivering power to meet system load demand. This minimum cost objective, leading to the term of economic dispatch, can be achieved by regulating the power supplied by each unit to take advantage of its unique operating cost characteristics.

Wood and Wollenberg (1996) present the following generic formulation of an economic dispatch model.

Minimize

$$F_T = \sum_{i=1}^{N} F_i(P_i)\,, \tag{2.2}$$

Subject To

$$P_{load} - \sum_{i=1}^{N} P_i = 0 \text{,} \tag{2.3}$$

where,

F_T = total Cost for supplying the indicated load,
F_i = the Cost Rate for a particular generating unit,
P_i = the Electrical Power generated by a particular unit, and
P_{load} = total received power for consumption.

In simple terms, the objective function (F_T) is equal to the total cost for supplying the indicated load. The problem is to minimize F_T subject to the constraint that the sum of the powers generated must equal demand. Note that in this static form no transmission losses or any operating limits are explicitly stated. Economic dispatch has generally been used as a single electric utility control area method for determining which generating units will be committed to meet a given demand in the most economic fashion. It does not take into account any electrical characteristics of the power system.

2.5.2 Unit Commitment

Economic dispatch and unit commitment seem like very similar topics. Wood and Wollenberg (1996) contrast the two in the following manner.

> The economic dispatch problem assumes that there is known demand and *N* generating units already connected to the system and available for optimum operational dispatch. In contrast, unit commitment is more complex since it introduces more electrical and time factor constraints into the dispatch problem. Under unit commitment, the problem assumes to have known demand and *N* generating units available, but not necessarily

operational or connected to the system at the present time. The increased number of constraints adds more reality into problem solutions.

Unit commitment literature has been a prominent research topic for at least the last twenty-five years. The literature has provided general solutions to determine the schedule of generating units within a power system subject to device and operating constraints. Most have difficult solution methodologies.

Unit commitment literature is both wide in spectrum and deep in computational analysis. Sheblé and Fahd (1994) formulate the generic unit commitment problem as follows.

Minimize

Operational Cost (Fuel, Maintenance, and Start-Up)

Subject To

(1) minimum up-time and down-time constraints
(2) crew constraints
(3) ramp rate limits
(4) unit capability limits
(5) deration of units
(6) unit status
(7) generation constraints
(8) reserve constraints

In addition to the above constraints, the generators must satisfy system load and provide for system losses and spinning reserves.

There are many different solution methods for the unit commitment problem. Solution procedures to more complex models include:

(1) Integer and Mixed-Integer Programming,
(2) Branch-and-Bound Techniques,
(3) Linear Programming,
(4) Dynamic and Linear Programming,

(5) Separable Programming,
(6) Network Flow Programming,
(7) Lagrangian Relaxation,
(8) Expert Systems/Artificial Neural Networks, and
(9) Risk Analysis.

More complex Unit Commitment models include inherent electrical system characteristics in the constraints. Baldick (1995) states that because of introduced computational complexities from these constraints, *ad hoc* methods have historically been used to schedule generators. However, systematic techniques continue to be sought to solve the problems because optimal schedules can yield large cost savings compared to *ad hoc* schedules.

Sheblé and Fahd (1994) state the primary reason for solving the unit commitment problem is to provide a cost basis for transaction pricing. They continue to point out that research for the future should concentrate on relating the unit schedule to the available transactions with the intent of selecting the least cost, yet reliable, option.

Unit commitment has also historically been a single electric utility control area method for determining which generating units will be allocated. It sparingly takes into account production costs or any electrical characteristics of the power system. Kahn, et al. (1996) point out that in most cases the algorithms used to commit generation assets do not take transmission network constraints into account or do so only in an incomplete fashion. Optimal power flow is the subject which allows for the formulation of transmission network constraints for power system analysis.

2.5.3 Optimal Power Flow

The concept of optimal power flow comes from the combination of economic dispatch with the theory of electric power flow. The formulation of an optimal power flow problem results when economic dispatch is stated in terms of generation costs and the power dispatched from the generation units is subject to a set of equations needed to characterize the flow of power from dispatched generation units to demand loads.

Optimal power flow has had a long history of development and is a very flexible analytical tool. Applications of optimal power flow allows for the determination of an optimum generation pattern and solutions to other control variables in order to achieve minimum cost power production while meeting transmission system limitations. Current research in optimal power flow centers on the ability to solve for an optimal solution that takes into account system security.

Wood and Wollenberg (1996) discuss many different formulations of objective functions to optimal power flow problems. One formulation is to solve for the minimum power production cost and concurrently balance all system power flows. They also show that it is common to express an optimal power flow as a minimization of electrical losses on the transmission system. Another way is to express it as the minimum shift of generation and other controls from an optimal operating point. Still another way could be to allow

for the adjustment of loads in order to determine a minimum load shedding schedule under emergency conditions.

An optimal power flow is a very large and very difficult mathematical programming problem. Wood and Wollenberg (1996) state that almost every mathematical programming approach that can be applied to this problem has been attempted and it has taken developers many decades to develop computer codes that will solve an optimal power flow model reliably. In their textbook they introduce five methods of solution to optimal power flow problems. They are:

(1) the Lambda Iteration Method,
(2) Gradient Methods,
(3) Newton's Method,
(4) the Linear Programming Method, and
(5) the Interior Point Method.

Wood and Wollenberg (1996) conclude their discussion of optimal power flow by stating that, regardless of the objective function, an optimal power flow solution must satisfy a complete set of power system constraints.

Kahn, et al. (1996) discuss using the Transportation algorithm as another method of solution to optimal power flow problems. They consider it to be a simple form of solution since it neglects electrical characteristics but does provide an approximate optimal solution.

2.5.4 Transportation Model for Optimal Power Flow

A transportation network model can be used to approximate optimal system power flows. With this modeling method, power flow on an electrical power line is assumed to

be limited only by the characteristics of the line regardless of system demands of other power lines in the system. This is analogous to power being transported in trucks on a highway.

Stoll (1989) develops a two-area production model example utilizing the transportation model for interconnecting transmission network constraints. Adhering to conservation of power flow conditions, interconnecting transmission power inflow/outflow equations are derived as follows.

$$Load_{AreaA} = Generation_{AreaA} - Transmission_{A \rightarrow B} , \tag{2.4}$$

and

$$Load_{AreaB} = Generation_{AreaB} + Transmission_{A \rightarrow B} . \tag{2.5}$$

For systems with multiple interconnections, equations similar to Equation 2.4 and Equation 2.5 apply, but in a more general form where transmission flows from all areas are included. The advantage of using the transportation model is the ease with which analysis can be performed. Its disadvantage is that electrical networks are not precisely modeled.

2.5.5 Multiarea Production Simulation

Electric utilities in the 48 contiguous United States are interconnected with other electric utilities. Interconnections introduce operating cost and reliability benefits to all interconnected parties. Sometimes neighboring utilities may be able to generate power at a lower cost than another given utility providing an incentive

for a higher cost utility to purchase power outside of its control area. If the power can be purchased at less than the purchaser's generating cost and sold at a price higher than the seller's generating cost, then there are mutual incentives for both purchaser and seller to conduct business transactions.

Stoll (1989) introduces the subject of multiarea production simulation as a means for an electric utility to analyze opportunities for power purchases or sales. The procedure simulates the operation of each interconnected utility, calculates when economic interchanges may occur, and calculates the interchange purchase and sale prices. With this method he extends the subject of economic dispatch. He introduces transmission interconnection limitations into the interchange of power between interconnected utilities and uses either:

(1) a linear electric transmission model, or
(2) a transportation model

to represent transmission system limitations. The limitations must be observed so that no power system constraint violations occur.

A transmission network interconnecting several electric utilities may comprise many transmission lines of several different voltage levels. Stoll (1989) shows that a theoretically correct procedure would be to model all interconnecting lines and internal lines of each utility and solve the multiarea production simulation using an AC (alternating current) power flow solution technique that

recognizes thermal, voltage, and frequency stability constraints in conjunction with economic dispatch and unit commitment principles. However, he points out that an AC power flow technique is too computer-resource intensive to use with a simulation of 8760 hours/year. Therefore, the exact AC power flow equations are generally reduced in detail to a DC (direct current/linear) power flow model or reduced further to a transportation model.

2.6 Production Costs: Average vs. Marginal

Stoll (1989) discusses a fundamental principle in developing a priority list for the economic dispatch or unit commitment of generation facilities. He uses empirical analysis to show that the most economic operation tends to result when the fewest number of generating units are producing electric power. In his analysis, he demonstrates how a power system with many generating facilities could operate all of them to serve total demand. Since the sum of the power output from all of the facilities must equal the total load demanded, many of the generating facilities could be operating at low-power output, which results in an expensive operating cost. Alternatively, he states, a power system should commit only enough generating facilities to meet the load demanded. In this case, total average operating costs are lower. Therefore, minimum operating cost policy is to dispatch the minimum amount of capacity for service based on some economic priority.

One might argue that an average cost approach to economic dispatch is not an optimal method for prioritizing facilities. An optimal method for ranking electric generation facilities would be by marginal costs. The argument is generally valid, but in the electric utility industry, it is possible for average costs and marginal costs to yield similar results.

The relationship between marginal and average costs is shown in the following equations.

$$TC = C(q) , \tag{2.6}$$

$$AC = C(q) / q , \tag{2.7}$$

$$MC = \partial C(q) / \partial q , \tag{2.8}$$

and noting that

$$\partial AC / \partial q = [q(\partial C(q) / \partial q) - C(q)] / q^2 , \tag{2.9}$$

yields

$$MC = AC + (\partial AC / \partial q)q . \tag{2.10}$$

From above, marginal cost is equal to average cost plus an adjustment factor $[(\partial AC/\partial q)q]$. This factor effect is the "damage" (or "gain," in the case of falling marginal costs) to all factors caused by an increase in output, which causes the cost for each unit of output to increase (or decrease, for falling marginal costs) (Silberberg 1990).

The adjustment factor can be neglected if a relatively flat supply curve exists since the adjustment factor term $[(\partial AC/\partial q)q]$ will be small, preserving the rankings, or equal to zero, creating equivalent rankings. Therefore, by

neglecting the adjustment factor of a relatively flat supply curve, an average cost method for prioritizing generation facilities for economic dispatch will yield results similar to a marginal cost method. Hence, average cost rankings can be a valid method of economic dispatch.

2.7 Review of Literature Summary

The chapter begins with an in-depth review of the Averch-Johnson hypothesis where arguments supporting and refuting it are presented. The chapter then proceeds to a review of existing stranded cost models. While each states its similarities to a "Bottom-Up" approach for estimating stranded costs, neither focuses on electric power production outside of any particular utility company. Each discusses lost revenues, which can loosely be interpreted as stranded profits. Whereas a true "Bottom-Up" approach does not strictly take into account lost revenues, it does allow for the estimation of stranded costs on an asset-by-asset basis. Next, an introduction to restructuring methods is reviewed. A Bilateral Contract method and a Poolco method are discussed along with the possibility of having the best of both methods as a third option.

The chapter then discusses technical issues pertinent to the dissertation model. It reviews power engineering literature in support of finding a pure "Bottom-Up" approach to estimating stranded generation costs. The subjects of economic dispatch, unit commitment, optimal power flow, transportation modeling for optimal power flow, and

multiarea production simulation are reviewed. Finally, the chapter moves forward to review power system production costs. The argument of average vs. marginal costs is presented. An optimal economic dispatch of generation facilities is obtained by evaluating each facility's marginal costs, but the literature suggests that there is a situation where average costs can be used as a good approximation to marginal cost rankings.

The model developed in the next chapter introduces a Poolco approach to multiple electric utility production with transmission system interconnections to estimate stranded generation facilities and their costs. It is a combination of economic dispatch, unit commitment, and optimal power flow literature when taken in context of multiarea production.

CHAPTER 3

THE LaDEUX DISPATCH MODEL WITH PLANNED EXPERIMENTATION

3.1 Introduction

The purpose of this chapter is to formulate a model to assist policy makers with the estimation of stranded generation facilities. This approach develops a model which results in the optimal economic dispatch of generation facilities and efficient utilization of transmission interconnections between control areas within a power pool. Traditional economic dispatch and unit commitment research has assumed that sufficient transmission capacity is present to support wheeling transactions. This, in fact, may not be true when deregulation becomes a reality. Thus, economic dispatch and efficient power wheeling need to be considered simultaneously, not separately as has been done in previous research.

A model to determine economic dispatch and optimal power flow for wheeling power between control areas can be easily formulated and solved as a transportation model, a specialized form of a linear programming model. Unfortunately, such a model would not consider the effects of power losses due to transmission. The inclusion of power losses results in a nonlinear mathematical programming model. While nonlinear programming models are much more difficult to solve, the resulting model more accurately portrays system dynamics. Sections 3.3 through 3.7 develop

such an economic dispatch model. In order to illustrate its formulation and solution, a simple, hypothetical problem is introduced and discussed in Sections 3.8 and 3.9.

It is important to test the sensitivity of the solution to the model under a variety of typical industry conditions. For instance, designed experimentation can be used to determine how conditional factors such as seasonal peak demand, power imports, and transmission interconnection costs affect stranded generation facilities and their costs. Sections 3.10 and 3.11 describe such factors. Section 3.12 outlines and explains the conditional factors used to test the sensitivity of the model to various changes in input parameters while Section 3.13 presents a solution methodology for determining the most likely economic dispatch of generation facilities and a means for estimating their stranded or uneconomic operating costs.

3.2 Aggregated Power System Literature Used for Modeling

The mathematical model developed in this chapter combines key elements of economic dispatch, unit commitment, optimal power flow, and multiarea production simulation literature by Stoll (1989), Sheblé and Fahd (1994), Baldick (1995), and Wood and Wollenberg (1996). A review of this literature can be found in Chapter 2, Section 2.5. The model developed here is robust in design and provides an approximate optimal solution to the system being modeled.

Economic dispatch models are typically limited to single company specific dispatch. The same is true for unit

commitment models. Expanding the scope to include multiple company control areas for economic dispatch and/or unit commitment requires the identification and inclusion of transmission lines between control areas.

However, to effectively analyze power wheeling between control areas, it is not necessary to become overly concerned with power flows within a control area. Optimal power flow modeling can be modified to contain only transmission interconnections if assumptions are made to assure that power flows within any control area are unconstrained and satisfy operational limits. Because of the increased scope it would present, details of optimal power flow within a control area are not being considered for the model.

3.3 LaDEUX: A Nonlinear Programming Model

The Poolco method to electric utility restructuring was chosen over the Bilateral Contract method for development of a nonlinear programming model to estimate stranded generation facilities and their costs. Given the two alternatives, the choice was simple. The Bilateral Contract approach is known to produce suboptimal dispatching of generation facilities because power contracts of any significant time duration do not react to changes in the market. This hedge against power prices can prevent the market from clearing at the optimal minimum production cost. Wu and Varaiya (1995) show that the Bilateral Contracts method faces two fundamental problems. First, they indicate

that a lack of coordination among independent trades can lead to the violation of transmission network constraints. Second, power flows are not taken into consideration by this method. Wu and Varaiya indicate that all power flows must be balanced throughout the network and that transmission losses must be included for maintaining a balance of power.

There is the option of having a power pool and allowing bilateral contracts to coexist. If this option were to occur, Stoft (1996) argues that for its success it would be necessary to clear the market for the power pool first and allow bilateral traders the option of trading with the least possible interference from the power pool. Implementing Stoft's guidelines would satisfy the problems identified by Wu and Varaiya.

After considering all methods to restructure the electric utility industry, it seems that implementing the Poolco method is arguably the better choice. Even though it does not allow consumers to "shop around" for power prices and without proper control mechanisms it can provide the possibility for producers to develop market power, it is technically the better method.

Therefore, the remainder of this section introduces a methodology for formulating LaDEUX (**L**ouisian**a**'s **D**eregulated **E**lectric **U**tility E**X**change), a nonlinear mathematical programming model for "Bottom-Up" analysis of an electric power system's generation facilities operating under the Poolco method for restructuring. The model's objective is

production cost minimization, but several other important features capture the behavior of the system's generation and transmission functions. In particular, the model optimizes generation facility dispatch as well as determines which interconnecting power transactions are needed to meet the system's summer or winter peak demand.

LaDEUX employs basic supply and demand characteristics. It first determines the availability of generation facilities and transmission interconnection capacity. Next, it dispatches facilities to meet total system summer or winter peak demand. It then utilizes transmission interconnections to deliver economically generated power to meet the seasonal peak demand in control areas with economically inferior production capabilities. The detailed objective functions and constraint equations can be found in Sections 3.5 and 3.6 of this chapter.

3.4 Modeling Notation

A notation index defining all subscripts, cost coefficients, decision variables, and system parameters is found in Table 3.1 below. It is used for the development of LaDEUX's objective functions and constraints.

3.5 Objective Functions

The objective functions developed for LaDEUX are piecewise, multi-term linear functions which minimize electric utility power production costs. They may also include bundled transmission interconnection costs for sensitivity analysis. Anderson (1972) makes use of a

TABLE 3.1
NOTATION INDEX FOR LaDEUX

COST COEFFICIENTS	**DEFINITION**
TC	Transmission Interconnection Usage Cost
AC_{jx}	Average Variable Cost of Control Area *j*'s Generation Facility *x*
ACC_{jx}	Average Variable Cost of Control Area *j*'s Contracting Generation Facility *x*
ACI_{jx}	Average Variable Cost of Control Area *j*'s Importing Generation Facility *x*
FC_{jx}	Fuel Cost of Control Area *j*'s Generation Facility *x*
FCC_{jx}	Fuel Cost of Control Area *j*'s Contracting Generation Facility *x*
FCI_{jx}	Fuel Cost of Control Area *j*'s Importing Generation Facility *x*
DECISION VARIABLES	**DEFINITION**
GF_{jx}	Control Area *j*'s Production from Generation Facility *x* in MW
CGF_{jx}	Control Area *j*'s Production from Contracting Generation Facility *x* in MW
IGF_{jx}	Control Area *j*'s Production from Importing Generation Facility *x* in MW
TL_{jky}	Transmission Interconnection Losses in MW for Line *y* from Control Area *j* to *k*
TP_{jky}	Transmission Interconnection Total Power in MW for Line *y* from Control Area *j* to *k*
TD_{jky}	Transmission Interconnection Power Delivered in MW for Line *y* from Control Area *j* to *k*
SYSTEM PARAMETERS	**DEFINITION**
$GFCAP_{jx}$	Capacity of Control Area *j*'s Generation Facility *x*
$CGFCAP_{jx}$	Capacity of Control Area *j*'s Contracting Generation Facility *x*
$IGFCAP_{jx}$	Capacity of Control Area *j*'s Importing Generation Facility *x*
SPD_j	Summer Peak Demand with Spinning Reserves for Control Area *j*
WPD_j	Winter Peak Demand with Spinning Reserves for Control Area *j*
$TCAP_{jky}$	Transmission Interconnection Capacity for Line *y* from Control Area *j* to *k*
V_{jky}	Transmission Interconnection Line-to-Line Voltage for Line *y* from Control Area *j* to *k*
Z_{jky}	Transmission Interconnection Impedance for Line *y* from Control Area *j* to *k*

piecewise linear cost function for his models determining least-cost investments for electricity supply. Smith (1993) also utilizes a piecewise linear cost function for his real time pricing model. In addition, Vardi and Avi-Itzhak (1981) use a piecewise linear cost function for their quantitative methods in determining short- and long-term planning of installed electric energy generating capacities.

Economic theory argues that marginal production costs are accurate representations of incremental production costs. In industry, marginal production costs are considered proprietary information by electric utilities, and they are difficult to estimate without detailed production cost data. Average variable production costs, on the other hand, are not proprietary, but they generally overstate marginal production costs and are not usually accepted as true representations of production costs.

Marginal production costs are determined by summing components consisting of fuel costs and other operations costs along with maintenance costs (O&M) and the variable portion of administrative and general (A&G) costs. There is considerable debate within the academic community as to what portions of O&M and A&G are fixed and what portions are variable. This in turn makes the estimation of marginal production costs almost impossible. The approach chosen to handle this dilemma uses boundaries to estimate marginal production costs. For one boundary, fuel cost alone is used to approximate marginal production cost. Average variable

production cost is used to approximate the other boundary. Therefore, any portion of O&M or A&G added to the fuel cost component in order to estimate a true marginal production cost is expected to be a fraction of average variable production costs. Hence, the true marginal cost of production is captured within the boundaries. Consequently, the model is developed with alternate objective functions: one to model one boundary and the other to model its opposing boundary for capturing true marginal production costs.

Several terms are needed to sum production costs for generation facilities selling electric power into the power pool. Each term is characterized by the type of facility dispatched to produce power for the pool. The types of facilities include local and contracted power plants internal to the pool as well as power imported to control areas from generation facilities external to it. Each type of facility accounts for one of the summation terms in each objective function found below.

3.5.1 Production Costs

The objective functions to minimize the average variable and fuel production costs during the peak hour of a year are found in Equations 3.1A and 3.1B respectively.

Minimize

$$\sum_j \sum_x AC_{jx} * GF_{jx} + \sum_j \sum_x ACC_{jx} * CGF_{jx} + \sum_j \sum_x ACI_{jx} * IGF_{jx} \; ,$$
$$\forall j; \forall x \; . \qquad (3.1A)$$

Minimize

$$\sum_{j}\sum_{x} FC_{jx} * GF_{jx} + \sum_{j}\sum_{x} FCC_{jx} * CGF_{jx} + \sum_{j}\sum_{x} FCI_{jx} * IGF_{jx}\ ,$$

$$\forall j; \forall x\ . \tag{3.1B}$$

A transmission interconnection cost term can be added to the first two objective functions if bundled transmission and production costs are required for the model. Each sale of power outside a control area requires a power producer to use transmission interconnection capacity. When power is sold outside of a producer's control area, the producer incurs a usage fee to reimburse a transmission interconnection owner for capital outlays and other expenses. The addition of the usage fee into the objective functions above can be accomplished by extending the original summation terms to include transmission interconnection usage costs.

Some argue that the addition of transmission interconnection costs into the objective functions defeats the purpose of industry restructuring. It allows for the rebundling of costs, which is against deregulation practices. By rebundling generation and transmission interconnection costs, it is possible to set a limit on the distance a generation facility can sell its power. As transmission interconnection costs rise by either distance calculation methods or pancaked tariffs, a generation facility's total cost of service, consisting of generation and transmission interconnection costs, may become higher than the market clearing price of a control area targeted

for sale. This situation makes economically produced power in one control area uneconomic for resale in another control area.

3.5.2 Bundled Production & Transmission Costs

The objective functions to minimize the average variable and fuel production costs with transmission interconnection costs during the peak hour of a year are found in Equations 3.2A and 3.2B respectively.

Minimize

$$\sum_j \sum_x AC_{jx} * GF_{jx} + \sum_j \sum_x ACC_{jx} * CGF_{jx} + \sum_j \sum_x ACI_{jx} * IGF_{jx} + \sum_j \sum_k \sum_y TC * TP_{jky} \ ,$$
$$\forall j \ni s(j) \neq \varnothing; k \in s(j); \forall x; \forall y \ , \qquad (3.2A)$$

Minimize

$$\sum_j \sum_x FC_{jx} * GF_{jx} + \sum_j \sum_x FCC_{jx} * CGF_{jx} + \sum_j \sum_x FCI_{jx} * IGF_{jx} + \sum_j \sum_k \sum_y TC * TP_{jky} \ ,$$
$$\forall j \ni s(j) \neq \varnothing; k \in s(j); \forall x; \forall y \ , \qquad (3.2B)$$

where s(j) is the set of all adjacent, successor control areas to control area j.

Although production cost minimization is the objective for LaDEUX, production facilities that are not part of or are partially part of the optimal solution are important for determining stranded costs. Each generation facility not dispatched to serve demand becomes a stranded facility. The same is true for a partially dispatched facility—it becomes a partially stranded facility. The identification of stranded facilities and the power pool's market clearing price are the most important modeling contributions for determining stranded generation facility costs.

3.6 Constraints

Generation facility capacities, control area seasonal peak demands, contract and import power supplies, transmission interconnection capacity, and loss characteristics all provide limitations for a power system. It is these limitations which are the basis for LaDEUX's constraints. Formulations and explanations of all system constraints are found in the following subsections.

3.6.1 Generation Facility Capacities

The sum of nameplate capacities for individual generation units within a facility imposes a maximum amount of power production for the facility. A control area may have several different types of generation facilities to supply power for the region. For instance, a control area may have generation facilities owned and operated by the local electric utility (GF_{jx}), and it may have internal and/or external non-utility facilities contracted to meet the demand for the area (CGF_{jx}). In addition to both of these providers, power may also be imported into the control area (IGF_{jx}). Regardless of the type of generation present to meet demand, each facility has its own capacity limitation ($GFCAP_{jx}$, $CGFCAP_{jx}$ and $IGFCAP_{jx}$). The mathematical formulation of capacity constraints for each type of generation facility is found in Equations 3.3, 3.4 and 3.5.

(1) *Local Electric Utility Generation Capacity*

$$GF_{jx} \leq GFCAP_{jx}, \quad \forall j; \forall x. \tag{3.3}$$

(2) *Contracted Non-Utility Generation Capacity*

$$CGF_{jx} \leq CGFCAP_{jx}\,, \quad \forall j; \forall x\,. \tag{3.4}$$

(3) *Imported Generation Capacity*

$$IGF_{jx} \leq IGFCAP_{jx}\,, \quad \forall j; \forall x\,. \tag{3.5}$$

3.6.2 Control Area Demand Balancing

Satisfying planned peak demand within a control area can be accomplished either through generation resources inside the area or from power flowing into the area through transmission interconnections. To balance, LaDEUX simply sums power produced within a control area (GF_{jx} and CGF_{jx}) with power flows into the area (TD_{jxy}), removes any power leaving the area for resale in another control area (TP_{jxy}) while satisfying peak demand with the remainder. A simple illustration of control area peak demand balancing can be found in Figure 3.1.

Peak demand for any control area is made up of two components. The first component is the actual load[1] which must be served. The second component concerns "spinning (generation) reserves" which are used to meet demand under emergency conditions.

In order to provide users with reliable service, utilities have adopted a tactic of running one or more extra generation units. The units are productive, but supply electric power at a very low rate of output. Such units are said to provide spinning reserves. Spinning reserve generators can increase power production within a few

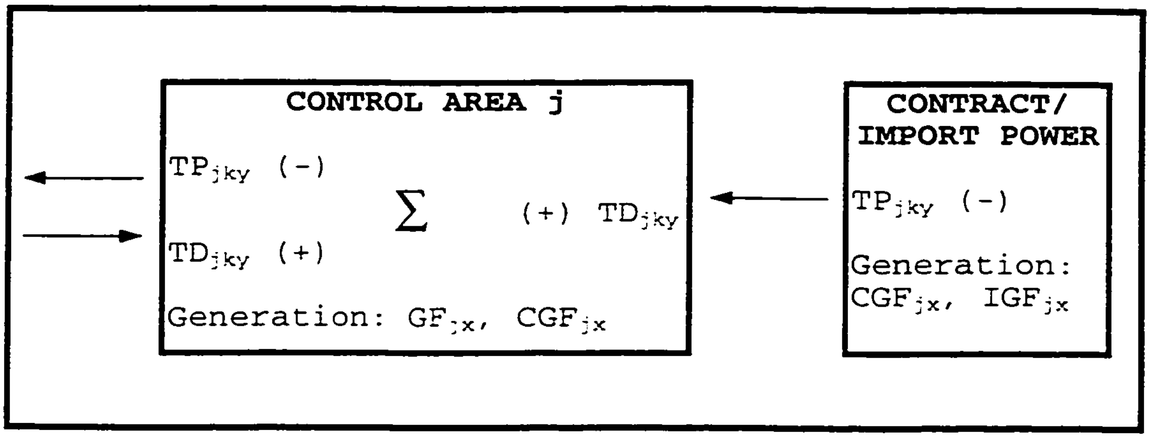


FIGURE 3.1
CONTROL AREA DEMAND BALANCING CONSTRAINT DIAGRAM

seconds, thereby avoiding a system failure when a producing generator fails. The continuous operation of spinning reserves is expensive, but has long been an essential element of reliable power supply in the U.S. and Canada (Stalon, 1997). The economics of spinning reserves provide powerful incentives for all but the very largest utilities to interconnect in order to share such reserves. Two electric utilities that interconnect with a transmission line of sufficient capacity can use the same spinning reserves, thereby reducing imposed federal requirements to provide their own reserves.

Both components of peak demand are expected to exhibit seasonal effects. Summer peak (SPD_j) and winter peak (WPD_j) demand are expected to vary generation facility dispatching. As demand increases from winter to summer, more facilities will be dispatched to increase the supply of electric power. The increase in demand strands fewer facilities, but as

demand decreases from summer to winter, fewer facilities are dispatched. Therefore, the supply of electric power is reduced. The decrease in demand from the seasonal effect strands more facilities.

The constraints formulated below incorporate seasonal demand effects for balancing control area demands. The mathematical formulation for seasonal control area demand balancing is found in Equations 3.6A and 3.6B.

(1) *Summer Seasonal Effect on Control Area Demand Balancing*

$$\sum_{x} GF_{jx} + \sum_{x} CGF_{jx} + \sum_{k}\sum_{x} TD_{jkx} - \sum_{k}\sum_{x} TP_{jkx} = SPD_j \ ,$$

$$\forall j \ni s(j) \neq \varnothing; k \in s(j); \forall x; \forall y \ . \qquad (3.6A)$$

(2) *Winter Seasonal Effect on Control Area Demand Balancing*

$$\sum_{x} GF_{jx} + \sum_{x} CGF_{jx} + \sum_{k}\sum_{x} TD_{jkx} - \sum_{k}\sum_{x} TP_{jkx} = WPD_j \ ,$$

$$\forall j \ni s(j) \neq \varnothing; k \in s(j); \forall x; \forall y \ . \qquad (3.6B)$$

3.6.3 Contract and Import Facility Power Balancing

Quite often a power pool may have external power producers who wish to sell economically produced power to the pool through control areas with uneconomic production costs. These producers may be contracted by the power pool to do so, or they may simply be entrepreneurs who wish to sell excess power. Figure 3.1 illustrates how power can be wheeled from externally located contracting (CGF_{jx}) or importing (IGF_{jx}) generation facilities to economically inferior control areas.

These power producers are dependent upon the capacity of connecting transmission lines (TP_{jky}) for wheeling power to the pool. It is therefore necessary for LaDEUX to assure that any amount of contracted and/or imported power sold into the pool does not exceed the capacity of the transmission lines connecting it with the external generation sources.

The mathematical formulation for control area contract and import power balancing is found in Equation 3.7.

$$\sum_{x} CGF_{jx} + \sum_{x} IGF_{jx} - \sum_{k}\sum_{y} TP_{jky} = 0 \,,$$

$$\forall j \ni s(j) \neq \varnothing; k \in s(j); \forall x; \forall y \,. \tag{3.7}$$

3.6.4 Transmission Interconnection Capacity

Sufficient transmission interconnection capacity is vital for wheeling power between control areas within the power pool. Similar to generation facility production limitations, transmission interconnections between control areas have limitations too. A constraint is needed to assure that power wheeled between control areas (TP_{jky}) does not exceed the capacity of the transmission lines ($TCAP_{jky}$) interconnecting the areas. More simply put, the total power transferred across an interconnection cannot be more than the total capacity of the interconnection. For modeling purposes it is therefore assumed that power flow on an interconnecting transmission line is limited only by the characteristics of the line regardless of the loadings of other interconnecting lines in the power system. Stoll

(1989) makes the same assumption for his transportation optimal power flow model.

The mathematical formulation for transmission interconnection capacity is found in Equation 3.8.

$$TP_{jky} \leq TCAP_{jky} ,$$

$$\forall j \ni s(j) \neq \varnothing; k \in s(j); \forall y . \qquad (3.8)$$

3.6.5 Transmission Interconnection Losses

Electrical losses are mathematically represented as a quadratic function. Thus, nonlinearities are imposed on the model when representing transmission interconnection losses for constraint purposes. These nonlinearities results in a model that is much more complex and difficult to solve. Linear programming solution methods such as the Simplex Method or the Transportation Algorithm cannot properly handle constraints with nonlinear functions and another means for solution must be used.

Formulating a generalized transmission interconnection loss constraint requires some basic power engineering knowledge. However, the derivation is relatively straight forward and is presented in subsequent paragraphs.

To begin, total power (TP) on a transmission line can be separated into two components (see Figure 3.2):

(1) power that is delivered (TD) to a customer, and
(2) power that is lost (TL) during transmission.

$$TP = TD + TL . \qquad (3.9A)$$

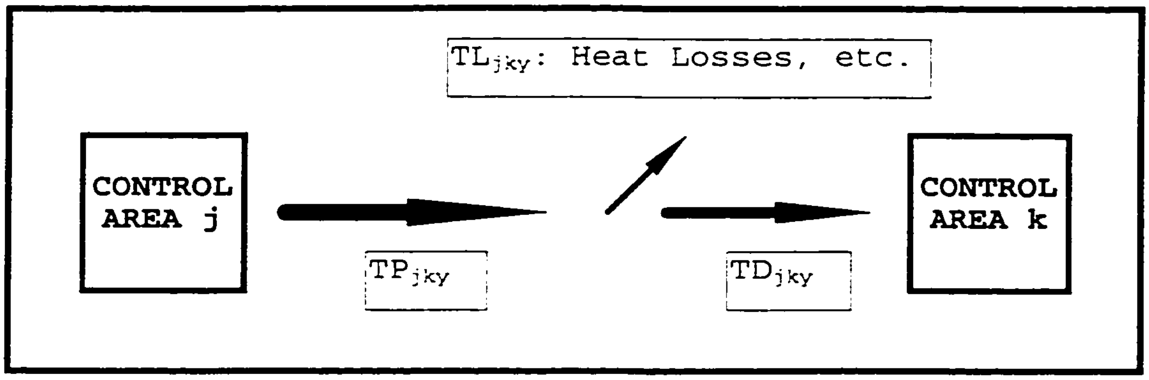


FIGURE 3.2
TRANSMISSION INTERCONNECTION POWER BALANCE DIAGRAM

In order to mathematically model a transmission line loss component, one must consider several different mathematical representations of transmission lines. Each representation is dependent upon line length. The electrically *short* line representation is for lines generally less than 50 miles in length. The *medium* line representation is for lines roughly 50 to 150 miles in length and the *long* line representation is considered for lines of more than 150 miles. Stevenson (1982) states that if an overhead transmission line is classified as electrically short, the mathematical representation of the shunt capacitance characteristic is so small that it can be omitted entirely with little loss of modeling accuracy, and one need only consider the series resistance (R) and series inductance (L) when obtaining an impedance parameter (Z) for the line. Ellgerd (1982) refers to transmission lines below approximately 100 miles in length as electrically *short*.

Since almost all transmission interconnections are less than 100 miles in length, electrically short line assumptions are used to derive the transmission interconnection loss constraint. Therefore, the impedance parameter (Z) of an electrically short transmission interconnection can be formulated as

$$Z = \sqrt{R^2 + L^2}\ , \qquad (3.9B)$$

and, subsequently, a mathematical representation of (three-phase) transmission interconnection losses can be formulated as

$$TL = 3 * I^2 * Z\ . \qquad (3.9C)$$

Next, the power delivered (TD) and loss (TL) variables can be rewritten in the following form

$$TP = (\sqrt{3} * V_{l-l} * I) + (3 * I^2 * Z)\ , \qquad (3.9D)$$

where,

V_{l-l} = transmission interconnection line-to-line voltage, and
I = line current of the transmission interconnection.

To determine interconnection line current (I), the power delivery portion of the total power equation,

$$TD = \sqrt{3} * V_{l-l} * I\ , \qquad (3.9E)$$

rearranges into

$$I = TD / (\sqrt{3} * V_{l-l})\ . \qquad (3.9F)$$

By substituting the value of the line current (I) into the loss portion of the total power equation, this yields:

$$TL = 3*(TD/(\sqrt{3}*V_{l-l}))^2*Z\ ,\qquad (3.9G)$$

which reduces to

$$TL = (TD^2/V_{l-l}^2)*Z\ ,\qquad (3.9H)$$

and finally assumes the mathematical constraint form found in Equation 3.10.

$$TL_{jky} = [((TD_{jky})^2*Z_{jky})/(V_{jky})^2]\ ,\quad \forall j \ni s(j) \neq \emptyset; k \in s(j); \forall y\ .\qquad (3.10)$$

3.6.6 Power Delivery and Loss Balance

As illustrated in the derivation for the loss constraint, the total power transferred across a transmission interconnection can be divided into two components. The total power on any interconnection is composed of power that is actually delivered to another control area and power that is lost across the interconnection (as a result of resistance heating, etc.) when completing a transaction. Figure 3.2 illustrates how electric power on transmission interconnections can be broken into its three component parts.

This constraint assures that the power on a transmission interconnection (TP_{jky}) is equal to the power delivered to a control area (TD_{jky}) and the power lost (TL_{jky}) while completing the transaction. The mathematical formulation for the transmission interconnection delivery and loss balance constraint is found in Equation 3.11.

$$TD_{jky} + TL_{jky} = TP_{jky}\ ,\quad \forall j \ni s(j) \neq \emptyset; k \in s(j); \forall y\ .\qquad (3.11)$$

3.7 Modeling Assumptions

Several modeling assumptions for determining optimal electric power flow on the transmission interconnections must be mentioned. Some assumptions are technical in nature and others are economic. A list of all modeling assumptions follows.

Assumption #1:

It is assumed that each control area has sufficient internal transmission capacity in order to satisfy demand within itself. The only transmission constraints considered in the model are for interconnections alone.

Assumption #2:

One-hour coincident summer or winter peak demands are assumed for all control areas. In addition, any changes in the quantity of electricity demanded, resulting from modeled price changes, are based on a system weighted average elasticity between residential, commercial, and industrial consumers.

Assumption #3:

All constraints with respect to electric power generation operating limits are assumed to be satisfied. In other words, thermal, voltage, and frequency stability limits are all assumed to be met for continuous operation of the electric power system.

Assumption #4:

Reactive power constraints are assumed to be satisfied by the local electric utility or its consumers. Recent research notes that there is a wide range of reactive power compensation equipment on the market, from low cost fixed capacitors to more expensive static VAr compensators (Kahn and Baldick, 1994). These devices are relatively inexpensive, and it is assumed that either consumers or competitive power providers will purchase the compensators in order to avoid power factor penalties from local transmitting electric utilities.

Assumption #5:

Qualifying Facilities (QFs) are assumed to be economic (Dismukes and Kliet, 1997). In other words, the avoided cost of generation revenue which QFs have received in the past is assumed to cover their production costs or QFs would not be selling power to their local electric utility.

Assumption #6:

It is assumed that all power sold into a power pool by a QF represents full QF capacity. A QF will not be able to use the power it needs and then sell its excess capacity into the power pool.

Assumption #7:

It is assumed that generation (supply-side) efficiencies do not accrue within the system as a

result of increased competition. In other words, the value of the entire generation system is equivalent to the sum of the component generation facilities.

Assumption #8:

It is assumed that no transmission synergies or losses accrue as a result of economic dispatch or coordination from the power pool. In other words, the value of the entire transmission system is equivalent to the sum of all component transmission lines.

Assumption #9:

The model assumes no market power which could influence the economic dispatch or bidding of generation facilities.

3.8 A Simple Example Formulation

In order to motivate development of LaDEUX, a small, simplified electric power system is introduced. The system is designed to economically dispatch generation facilities and wheel electric power between control areas when necessary.

The small electric power system consists of three control areas, seven generation facilities, and three interconnecting transmission lines. It is depicted in Figure 3.3. Its characteristics and system parameters are detailed in Table 3.2. It operates as a Poolco, and no reserve margins are required. Assume the system has a coincident one-hour peak demand for all three control areas.

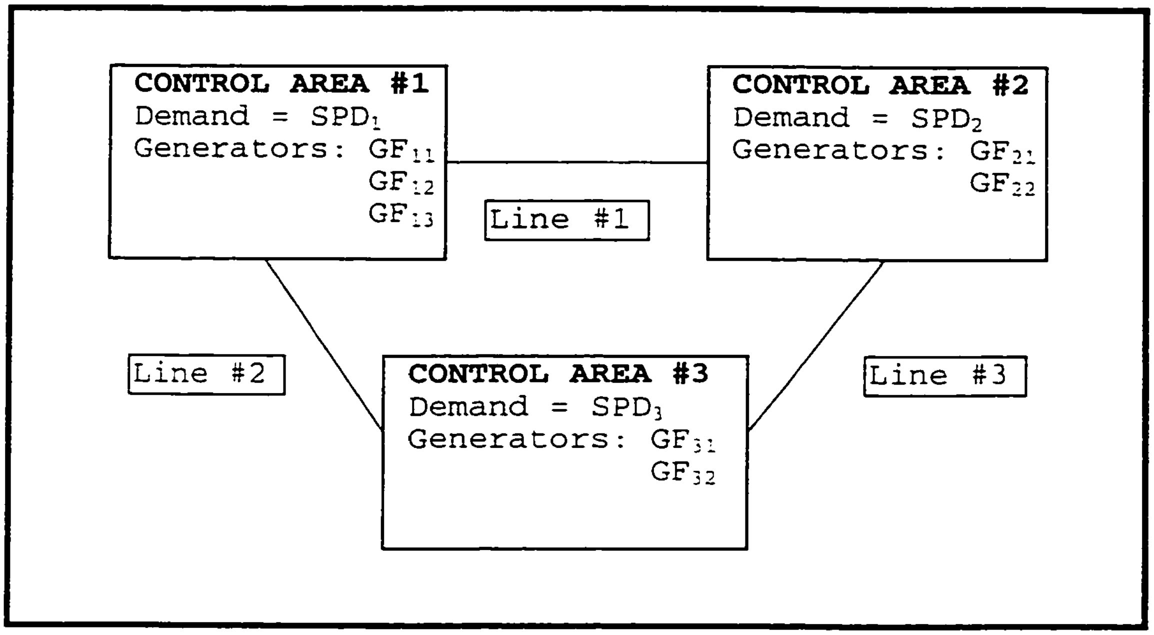


FIGURE 3.3
SIMPLE EXAMPLE POWER SYSTEM

TABLE 3.2
SIMPLE EXAMPLE POWER SYSTEM CHARACTERISTICS

CONTROL AREA #1	**CONTROL AREA #2**	**CONTROL AREA #3**
Peak Demand SPD_1 = 200 MW	Peak Demand SPD_2 = 125 MW	Peak Demand SPD_3 = 100 MW
Capacity GF_{11} = 100 MW GF_{12} = 150 MW GF_{13} = 50 MW	Capacity GF_{21} = 100 MW GF_{22} = 50 MW	Capacity GF_{31} = 75 MW GF_{32} = 50 MW
Power Pool Bid GF_{11} = \$4/MWh GF_{12} = \$5/MWh GF_{13} = \$6/MWh	Power Pool Bid GF_{21} = \$8/MWh GF_{22} = \$9/MWh	Power Pool Bid GF_{31} = \$15/MWh GF_{32} = \$16/MWh
LINE #1	**LINE #2**	**LINE #3**
Capacity = 100 MW between Control Areas #1 and #2	Capacity = 100 MW between Control Areas #1 and #3	Capacity = 100 MW between Control Areas #2 and #3
Cost = \$1/MWh	Cost = \$1/MWh	Cost = \$1/MWh
Voltage = 115 kV	Voltage = 115 kV	Voltage = 115 kV
Impedance = 10 Ω	Impedance = 10 Ω	Impedance = 10 Ω

It is a simple, straightforward procedure to formulate a nonlinear programming model for the problem in order to determine the economic dispatch of generation facilities and power transfers between control areas. Assume an objective function that minimizes production costs and transmission interconnection costs. The constraints necessary for model formulation include generator capacities, control area demand balancing, transmission interconnection capacity, transmission interconnection losses, and transmission interconnection delivery and loss balancing. An economic dispatch model for the simple example is found below.

NONLINEAR PROGRAMMING EXAMPLE MODEL

Minimize

$$\sum_{j}\sum_{x} AC_{jx} * GF_{jx} + \sum_{j}\sum_{k}\sum_{y} TC * TP_{jky} \ ,$$

Subject To

(1) $GF_{jx} \leq GFCAP_{jx}$, $\qquad \forall j; \forall x$,

(2) $\sum_{x} GF_{jx} + \sum_{k}\sum_{y} TD_{jky} - \sum_{k}\sum_{y} TP_{jky} = WPD_{j}$,

$\qquad \forall j \ni s(j) \neq \varnothing; k \in s(j); \forall x; \forall y$,

(3) $TP_{jky} \leq TCAP_{jky}$, $\qquad \forall j \ni s(j) \neq \varnothing; k \in s(j); \forall y$,

(4) $TL_{jky} = [((TD_{jky})^2 * Z_{jky}) / (V_{jky})^2]$, $\qquad \forall j \ni s(j) \neq \varnothing; k \in s(j); \forall y$,

(5) $TD_{jky} + TL_{jky} = TP_{jky}$, $\qquad \forall j \ni s(j) \neq \varnothing; k \in s(j); \forall y$.

EXAMPLE MODEL FORMULATION

Minimize

$$\begin{aligned} & 4*GF_{11} + 5*GF_{12} + 6*GF_{13} + 8*GF_{21} \\ + & 9*GF_{22} + 15*GF_{31} + 16*GF_{32} + 1*TP_{121} \\ + & 1*TP_{211} + 1*TP_{132} + 1*TP_{312} + 1*TP_{233} \\ + & 1*TP_{323} \end{aligned} \tag{3.12}$$

Subject To

(1) *Generator Capacities*

$$GF_{11} \leq 100 \tag{3.13}$$
$$GF_{12} \leq 150 \tag{3.14}$$
$$GF_{13} \leq 50 \tag{3.15}$$
$$GF_{21} \leq 100 \tag{3.16}$$
$$GF_{22} \leq 50 \tag{3.17}$$
$$GF_{31} \leq 75 \tag{3.18}$$
$$GF_{32} \leq 50 \tag{3.19}$$

(2) *Control Area Demand Balancing*

$$GF_{11} + GF_{12} + GF_{13} + TD_{211} + TD_{312} - TP_{121} - TP_{132} = 200 \tag{3.20}$$
$$GF_{21} + GF_{22} + TD_{121} + TD_{323} - TP_{211} - TP_{233} = 125 \tag{3.21}$$
$$GF_{31} + GF_{32} + TD_{132} + TD_{233} - TP_{312} - TP_{323} = 100 \tag{3.22}$$

(3) *Transmission Interconnection Capacity*

$$TP_{121} \leq 100 \tag{3.23}$$
$$TP_{211} \leq 100 \tag{3.24}$$
$$TP_{132} \leq 100 \tag{3.25}$$
$$TP_{312} \leq 100 \tag{3.26}$$
$$TP_{233} \leq 100 \tag{3.27}$$
$$TP_{323} \leq 100 \tag{3.28}$$

(4) *Transmission Interconnection Losses*

$$TL_{121} = ((TD_{121})^2*10)/(115)^2 \tag{3.29}$$
$$TL_{211} = ((TD_{211})^2*10)/(115)^2 \tag{3.30}$$
$$TL_{132} = ((TD_{132})^2*10)/(115)^2 \tag{3.31}$$
$$TL_{312} = ((TD_{312})^2*10)/(115)^2 \tag{3.32}$$
$$TL_{233} = ((TD_{233})^2*10)/(115)^2 \tag{3.33}$$
$$TL_{323} = ((TD_{323})^2*10)/(115)^2 \tag{3.34}$$

(5) *Transmission Interconnection Delivery and Loss Balance*

$$TD_{121} + TL_{121} = TP_{121} \tag{3.35}$$
$$TD_{211} + TL_{211} = TP_{211} \tag{3.36}$$
$$TD_{132} + TL_{132} = TP_{132} \tag{3.37}$$
$$TD_{312} + TL_{312} = TP_{312} \tag{3.38}$$
$$TD_{233} + TL_{233} = TP_{233} \tag{3.39}$$
$$TD_{323} + TL_{323} = TP_{323} \tag{3.40}$$

3.9 Solution to the Simple Example Formulation

Solution to the example problem introduced in the previous section is easily obtained using software developed to solve nonlinear mathematical programming problems. Table 3.3 displays the simple problem's solution.

The solution indicates how economic dispatch was performed based on production cost bids by the generation facilities into the power pool. Notice that Control Area #1's generation facilities are the most economic at $4, $5 and $6 per MWh and get dispatched into the system first. They provide 300 MW of the 431.2 MW needed to meet the system's one-hour peak demand and transmission interconnection losses. Again, notice that Control Area #2's generation facilities are the next most economic at $8 and $9 per MWh. These generation facilities provide the final 131.2 MW needed to meet the one-hour peak demand and transmission interconnection losses of the system.

Results from the nonlinear programming model also indicate how power transfers take place within the simple system. Line #2 transfers 89.7 MW from Control Area #1 to Control Area #3 while losing 6.1 MW across the

TABLE 3.3
NONLINEAR PROGRAMMING SOLUTION
FOR THE SIMPLE EXAMPLE POWER SYSTEM

CONTROL AREA #1	**CONTROL AREA #2**	**CONTROL AREA #3**
GF_{11} = 100.0 MW	GF_{21} = 100.0 MW	GF_{31} = 0.0 MW
GF_{12} = 150.0 MW	GF_{22} = 31.2 MW	GF_{32} = 0.0 MW
GF_{13} = 50.0 MW		
LINE #1	**LINE #2**	**LINE #3**
TD_{121} = 4.2 MW	TD_{132} = 89.7 MW	TD_{233} = 10.3 MW
TL_{121} = 0.0 MW	TL_{132} = 6.1 MW	TL_{233} = 0.1 MW
TD_{211} = 0.0 MW	TD_{312} = 0.0 MW	TD_{323} = 0.0 MW
TL_{211} = 0.0 MW	TL_{312} = 0.0 MW	TL_{323} = 0.0 MW

interconnection. Line #1 transfers 4.2 MW from Control Area #1 to Control Area #2 while accruing negligible losses across the interconnection. Finally, Line #3 transfers the remaining 10.3 MW from Control Area #2 to Control Area #3 while losing 0.1 MW across the interconnection.

Since there is sufficient transmission interconnection capacity to satisfy individual control area demands, the major finding of this simple example is the stranded generation facilities of Control Area #3. The market clearing price for electricity for this example is $9 per MWh[2]. Control Area #3's generation bids were well above this price, so its facilities were not dispatched into the system. If Control Area #3's facilities are investor-owned, the cost of each facility must be determined for stranded cost recovery.

3.10 Model Analysis

The purpose of the chapter so far has been formulation of a modeling methodology to characterize economic power production and wheeling transactions using estimated marginal production costs, generation facility and transmission system parameters, and seasonal peak demand. This methodology determines a power system's minimum production cost and market clearing price and identifies stranded generation facilities. One must keep in mind that formulation of any model is just a method of simplifying and describing a real problem through the use of mathematics. No matter how significant the simplification is, the model must be evaluated before its results can be accepted.

The purpose of the remainder of the chapter is to evaluate model results through designed experimentation and supply a solution methodology for estimating stranded generation facility costs. Through experimental evaluation, purposeful changes are made to LaDEUX's input variables so that one can observe and identify reasons for changes in its stranded generation facility output response. Empirical experimentation of the economic dispatch methodology is expected to provide more detailed solutions for answering important stranded cost questions. The underlying motivation of the sensitivity analysis is to precisely determine stranded and uneconomically dispatched generation facilities and furnish cost guidelines to regulatory bodies for policy

decisions. Details concerning the factors important for empirical experimentation follow.

3.11 Factors for Model Analysis

The primary decision for the LaDEUX economic dispatch model is total generation facility production costs, which are a function of its corresponding production cost coefficients. But, economically dispatched, uneconomically dispatched, and non-dispatched facilities are greatly dependent upon seasonal peak demand and the amount of power imported to the system as well. A third factor, the transmission interconnection usage cost associated with wheeling electric power, can further constrain the results of the other two factors. Each of the factors for empirical experimentation is described below.

3.11.1 Seasonal Peak Demand Factor

The objective of using seasonal peak demand factors allows one to determine the amount of production needed to meet peak demand during the summer or winter seasons, and thus, creates two factor levels for sensitivity analysis. Peak demand is defined as the highest electric requirement including losses experienced by a bulk electric system in a given period (e.g., a day, month, season, or year). It is equal to the sum of the metered (net) power outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system often expressed in MW (IEEE-PES, 1996). For southern states, the production required during the winter season is

considerably less than the amount required during summer months. The reverse is true for northern states. Thus, depending upon geography, there is a base production requirement (must-run facilities) for one season and hence, a base number of non-dispatched generation facilities. As the seasons change, peak demand rises from base production to fulfill the new, higher peak demand and other less economically productive and previously stranded generation facilities must be dispatched to meet the new demand. Therefore, depending upon seasonal peak demand, the number of stranded generation facilities and their costs can vary.

3.11.2 Power Imports Factor

The objective of using a power import factor allows one to determine the amount of power pool production needed to meet seasonal peak demand. If imports are not allowed into the power pool, the number of stranded generation facilities will actually depend upon the pool's seasonal peak demand. But, if power imports are allowed into the power pool, the actual number of stranded generation facilities may increase depending upon the pool's market clearing price.

For sensitivity analysis, power imports are set at two levels. For the first level, consider the situation of operating the power pool as a closed system, effectively allowing no power imports into the pool. In a closed system, the number of stranded generation facilities depends only on production costs and seasonal demand. For the second level,

consider the situation where the market clearing price dictates the amount of power desired from sources outside the pool. This is considered to be an open system. The amount is constrained only by the capacity of the transmission interconnections available to import the power. Thus, if external producers have excess production capacity and their production costs are less than a closed system's market clearing price, then the pool will accept as much power as transmission interconnections will allow. This situation effectively lowers the pool's market clearing price. For an open system, the number of stranded generation facilities depends on production costs, seasonal demand, and the amount of imported power. Imported power can greatly affect the number of stranded generation facilities; therefore, depending upon the level of power imports, the number of stranded generation facilities can vary immensely.

3.11.3 Transmission Interconnection Costs

Transmission interconnection costs were addressed earlier in Section 3.5. When implemented by LaDEUX, these costs are part of the model's objective function.

Using bundled transmission interconnection costs allows one to determine the amount of production needed to meet demand while considering the costs required for wheeling power between control areas. These costs can restrict power flows in a deregulated market. For instance, if transmission interconnection tariffs are incurred every time power is passed through a control area, there comes a

point where competition for a generation facility will cease to occur because of the pancaked transmission interconnection tariffs required to wheel power from the facility to the user. In this case it would be possible to draw a circle around any given generation facility to identify its market. Any transactions conducted outside the circle would be considered uncompetitive because of excessive tariffs.

For sensitivity analysis purposes, bundled and unbundled transmission interconnection costs will be studied. For the first level of sensitivity analysis, the power pool will be configured as a completely unbundled, functionally independent system where economic dispatching is based solely on production costs. For the second level of sensitivity analysis, transmission interconnection costs are added to LaDEUX to test the affect of pancaked tariffs on economic dispatching.

The postage stamp method is the pricing mechanism of choice for this research. It is a pricing method that is independent of distance and direction. The same charge is applied whether transmission distance is long or short. Therefore, depending upon bundled or unbundled transmission interconnection costs, the number of stranded generation facilities and their costs are expected to vary.

3.12 Designed Experiments

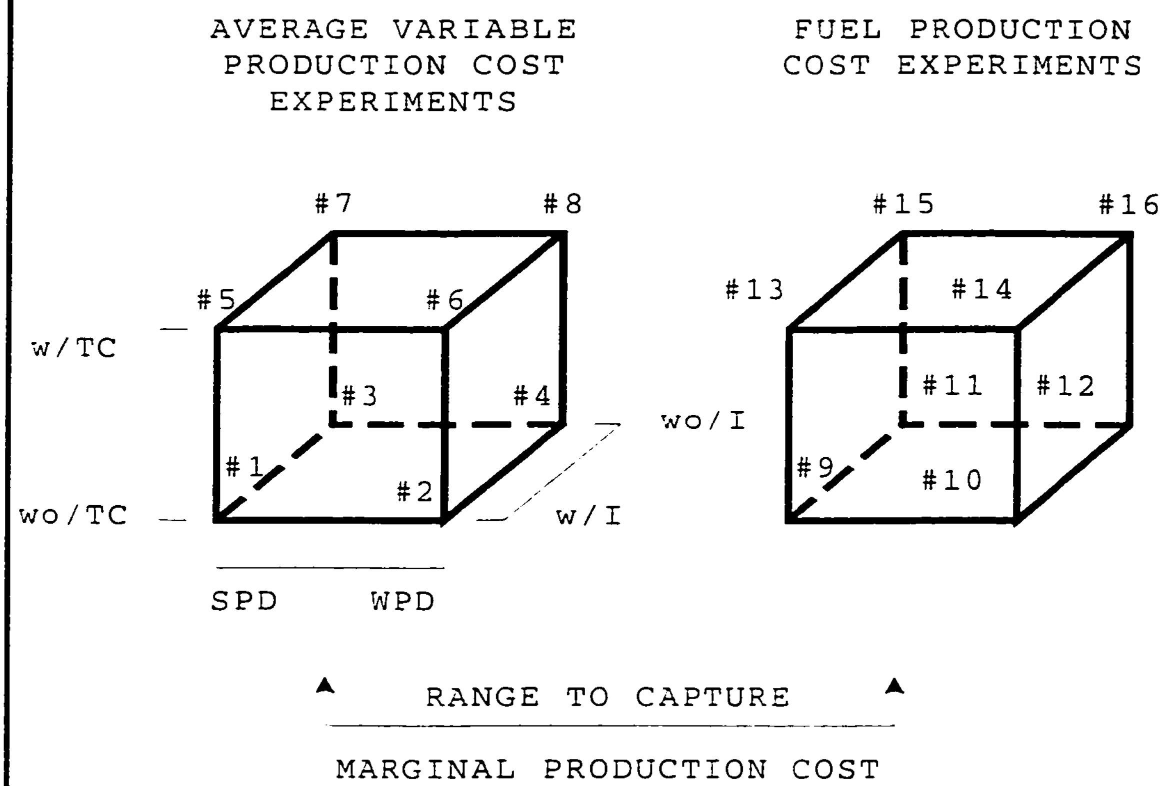
Much of the research in engineering, science, and industry is empirical and makes extensive use of designed

experimentation (Montgomery, 1991). Figure 3.4 illustrates the sixteen experiments developed for empirical analysis using the three factors discussed in Section 3.11. Production cost boundaries of average variable and fuel costs meant to capture true marginal production costs are designed to test the response of the LaDEUX model. Specific pairs of like experiments form the different ranges for capturing stranded generation facility costs from the boundary estimates of true marginal production costs.

3.13 LaDEUX Experimental Solution Methodology

Nonlinear mathematical programming, implemented through LINGO Hyper/PC Release 3.1 for Windows, is used for processing solutions to determine minimal production costs, dispatched and non-dispatched generation facilities, transmission interconnection loadings and losses, and the pool's market clearing price. The nonlinear solver software package employs both Successive Linear Programming (SLP) and Generalized Reduced Gradient (GRG) algorithms.

Models with nonlinear expressions are much more difficult to solve and may have several solutions which are said to be only locally optimal. LINGO does employ both of its solvers (SLP and GRG) together in an attempt to determine a global optimal solution, but there is no guarantee of obtaining such a solution. It is therefore necessary to assist the solvers by providing several initial generation facility production variable values. These values affect the "path" LINGO takes when searching for a solution.



NOTES:
1. SPD = Summer Peak Demand
2. WPD = Winter Peak Demand
3. I = Power Imports
4. TC = Transmission Interconnection Costs

FIGURE 3.4
EXPERIMENTAL DESIGN FOR
ECONOMIC DISPATCH SENSITIVITY ANALYSIS

For this research, several control areas will have their generation facility production variables initialized together to full capacity to meet Louisiana's seasonal demand. This provides an initial solution to the model and one "path" for determining an optimal solution. Several other "paths" will be created by grouping different control areas together and initializing their generation facility production variables to full capacity to meet the same seasonal peak demand.

The model's optimal solution identifies economic and uneconomic electric power production facilities and indicates the movement of electric power between control areas. Generation facilities not dispatched or uneconomically dispatched by LaDEUX in order to meet system demand are considered stranded and may be eligible for cost recovery.

LaDEUX's solution methodology is a two-step process. Each step contains multiple empirical experiments designed to capture true marginal production cost dispatch. Experimental solutions are obtained in the following manner.

Step One:

(A) Average variable production costs are processed by the model for each experimental case. Empirical experiments to be performed for *Step One* are found in Tables 3.4 and 3.5.

(B) A market clearing price for electric power production is determined.

(C) Non-dispatched investor-owned utility facilities are identified and the Net Book Value (original construction cost, plus capital additions, less depreciation) of each is determined to be its stranded cost.

(D) The Net Book Value for all remaining dispatched investor-owned utility facilities is then compared to revenues earned (market clearing price * quantity sold). A positive difference indicates a stranded benefit whereas a negative difference indicates a stranded cost. The total of each facility's stranded cost contribution becomes one boundary estimate for gross stranded generation facility costs.

TABLE 3.4
AVERAGE VARIABLE PRODUCTION COST EXPERIMENTS

POWER SYSTEM	*PEAK DEMANDS*	
	SUMMER	**WINTER**
WITH IMPORTS	Experiment #1	Experiment #2
WITHOUT IMPORTS	Experiment #3	Experiment #4

TABLE 3.5
AVERAGE VARIABLE PRODUCTION
AND TRANSMISSION COST EXPERIMENTS

POWER SYSTEM	*PEAK DEMANDS*	
	SUMMER	**WINTER**
WITH IMPORTS	Experiment #5	Experiment #6
WITHOUT IMPORTS	Experiment #7	Experiment #8

The procedure is performed again to determine the opposing boundary for capturing true marginal production costs.

Step Two:

(A) Fuel production costs are processed by the model for each experimental case. Empirical experiments to be performed for *Step Two* are found in Tables 3.6 and 3.7.

(B) A market clearing price for electric power production is determined.

(C) Non-dispatched investor-owned utility facilities are identified and the Net Book Value (original construction cost, plus capital additions, less depreciation) of each is determined to be its stranded cost.

(D) The Net Book Value for all remaining dispatched investor-owned utility facilities is then compared to revenues earned (market clearing price * quantity sold). A positive difference indicates a stranded benefit whereas a negative difference indicates a stranded cost. The total of each facility's stranded cost contribution becomes one boundary estimate for gross stranded generation facility costs.

Solutions obtained using the two different production costs provide boundary estimates for stranded generation facility costs. Since true marginal costs should be between average variable and fuel production costs, the boundary estimates

TABLE 3.6
FUEL COST EXPERIMENTS

POWER SYSTEM	*PEAK DEMANDS*	
	SUMMER	**WINTER**
WITH IMPORTS	Experiment # 9	Experiment #10
WITHOUT IMPORTS	Experiment #11	Experiment #12

TABLE 3.7
FUEL AND TRANSMISSION COST EXPERIMENTS

POWER SYSTEM	*PEAK DEMANDS*	
	SUMMER	**WINTER**
WITH IMPORTS	Experiment #13	Experiment #14
WITHOUT IMPORTS	Experiment #15	Experiment #16

found from this "Bottom-Up" procedure represent the best estimates, from available data, for determining stranded generation facility costs.

3.14 Modeling and Experimentation Summary

This chapter formulated a nonlinear programming methodology for determining minimal production costs for a power pool as well as allowing for the assessment of its stranded generation facilities. Once the facilities are known, financial procedures can be employed to estimate stranded generation facility costs. These procedures are discussed in greater detail in Chapter 4.

The chapter began by aggregating power system modeling literature in the context of network modeling. It then introduced an economic dispatch approach for model development. A notation index was provided to explain all

cost coefficients, decision variables, and system parameters used for developing an economic dispatch model. The chapter then proceeded to introduce a nonlinear programming modeling methodology called LaDEUX. Objective functions were set-up as piecewise linear cost functions which minimize the cost of electric power production during the peak hour of a season. If necessary, the objective functions could be modified to include transmission interconnection costs. The development of generation facility and transmission interconnection capacity, control area peak demand, transmission interconnection losses, and power balance constraints followed the objective function formulations. Nine assumptions were then presented to simplify technical and economic modeling issues.

The chapter then introduced a simple example problem which illustrated the significance of the Poolco approach to restructuring the electric utility industry. The simple example problem was then solved so one could obtain an understanding of economic dispatch, market clearing prices, and power transactions between control areas.

Designed experimentation was introduced next to test the sensitivity of the LaDEUX solution. Variations of seasonal peak demand, power import factors, and transmission interconnection costs were used to test total one-hour, coincident peak production cost and generation facility dispatch responses to the model. A generalized

two-step solution strategy was then presented for solving LaDEUX.

The model developed in this chapter is deterministic in design yet robust in the sense that it can handle any number of new generation facilities or transmission interconnections introduced into the system for analysis. The ability to do sensitivity analysis makes this research a significant contribution to electric utility industry restructuring literature.

3.15 End Notes

[1] The term "actual load" includes losses that occur during the generation, transmission, and distribution of electric power inside a control area.

[2] This is the bid price of the last generation unit dispatched and, hence, is the market clearing price.

CHAPTER 4

STRANDED GENERATION FACILITY COST ANALYSIS METHODS

4.1 Introduction

The LaDEUX model provides the user with an assessment of economically dispatched generation facilities needed to meet a power pool's peak demand. The information obtained from the assessment can further be used to estimate stranded generation facility costs, specifically, investor-owned utility stranded generation facility costs.

Two approaches for estimating these costs are presented in this chapter. The first is the Cost-of-Plant or book value method. For this method, each facility is evaluated solely on the criterion of economic dispatch. Book values are applied to stranded and partially stranded facilities in order to obtain stranded generation facility costs.

The other approach of estimating stranded generation facility costs is the Embedded Cost method. This method takes into consideration generation facilities that are dispatched, but are uneconomically operating in the market because of large sunk costs. For this method, an investor-owned utility's embedded rate is compared to the pool's market clearing price. Stranded costs accrue for a facility when its embedded rate is above the market clearing price for electricity, and stranded benefits accrue for a facility when its embedded rate is less than the market clearing

price. This method is actually an extension of the Cost-of-Plant method.

The chapter concludes with examples of each approach. The simple system introduced in Chapter 3 is reintroduced with more detailed cost parameters to demonstrate the methods.

4.2 Cost-of-Plant Method

For the Cost-of-Plant method, each facility is evaluated solely by an economic dispatch criterion that determines which generation facilities are necessary to meet a power pool's peak demand. The term "stranded generation facility" is interpreted in its strictest form.

Stranded costs are then determined in a very simple fashion. All facilities not dispatched are considered "stranded," and their book values are summed to indicate the pool's stranded generation facility costs. In the case of a fully dispatched generation facility, no book value costs are applied. Partially stranded facilities have costs allocated on a percentage basis based on the proportion of capacity not dispatched for peak demand to the facility's full load capacity. The Cost-of-Plant method is described mathematically by Equation 4.1.

$$Total\ Stranded\ Cost = \sum_{i=1}^{n}(BV_i * ND_i * Div_i)\ , \quad \forall n\ , \qquad (4.1)$$

where,

BV_i = Book Value of Generation Facility i,

ND_i = Proportion of Full Load Capacity for Generation Facility i Not Economically Dispatched, and

Div_i = Diversification Factor for investor-owned utilities that have Interstate Control Areas.

The diversification factor is necessary since most investor-owned utility systems cross state boundaries. This factor allows one to allocate stranded generation facility costs by state based on the power pool's peak demand. A mathematical representation of the diversification factor is found in Equation 4.2.

$$Div_i = State's\ Annual\ Peak\ Load \div System_i\ Annual\ Peak\ Load\ . \tag{4.2}$$

It is applicable to all generation facilities which provide electricity to customers of multistate companies.

The sunk costs associated with dispatched facilities are not considered stranded costs since the facilities are not strictly "stranded." These costs are considered to be costs for doing business since they are part of an original business strategy developed by an investor-owned utility company. Even though a regulatory body approves strategic capital expenditures, the original idea and subsequent expenditure justification reside with the investor-owned utility company, and hence, they are their costs to manage.

While this method is one approach for estimating stranded generation facility costs, it is not a true economic approach since it does not take into consideration generation facility sunk costs for operating facilities. It is a method that stringently estimates "stranded" generation facility costs. The next cost analysis method conforms to

the popular idea of including sunk costs as a component for determining stranded generation facility costs.

4.3 Embedded Cost Method

While some argue that stranded costs associated with book values of facilities that are strictly stranded are all that matter, others argue that facilities which are dispatched and operating above a market clearing price incur stranded costs too. Therefore, it is the intention of the Embedded Cost method to capture these excess costs. The flow chart of Figure 4.1 provides an illustrative explanation of how the Embedded Cost method is performed.

Fundamentally, this method is a comparison between a generation facility's embedded rate to a power pool's market clearing price. Stranded costs occur when a facility's embedded rate is above the market clearing price for electricity, and stranded benefits occur when the embedded rate is less than the market clearing price.

A facility's embedded rate is made up of several components. A general representation of the rate follows.

$$Embedded\ Rate = Expenses + (Return\text{ - }on\text{ - }Capital) + Depreciation\ . \qquad (4.3)$$

Each component is described in detail in the following subsections.

4.3.1 Expenses Component

The first component of a generation facility's embedded rate is made up of variable expenses. It is simply the sum of fuel and operation & maintenance expenses and

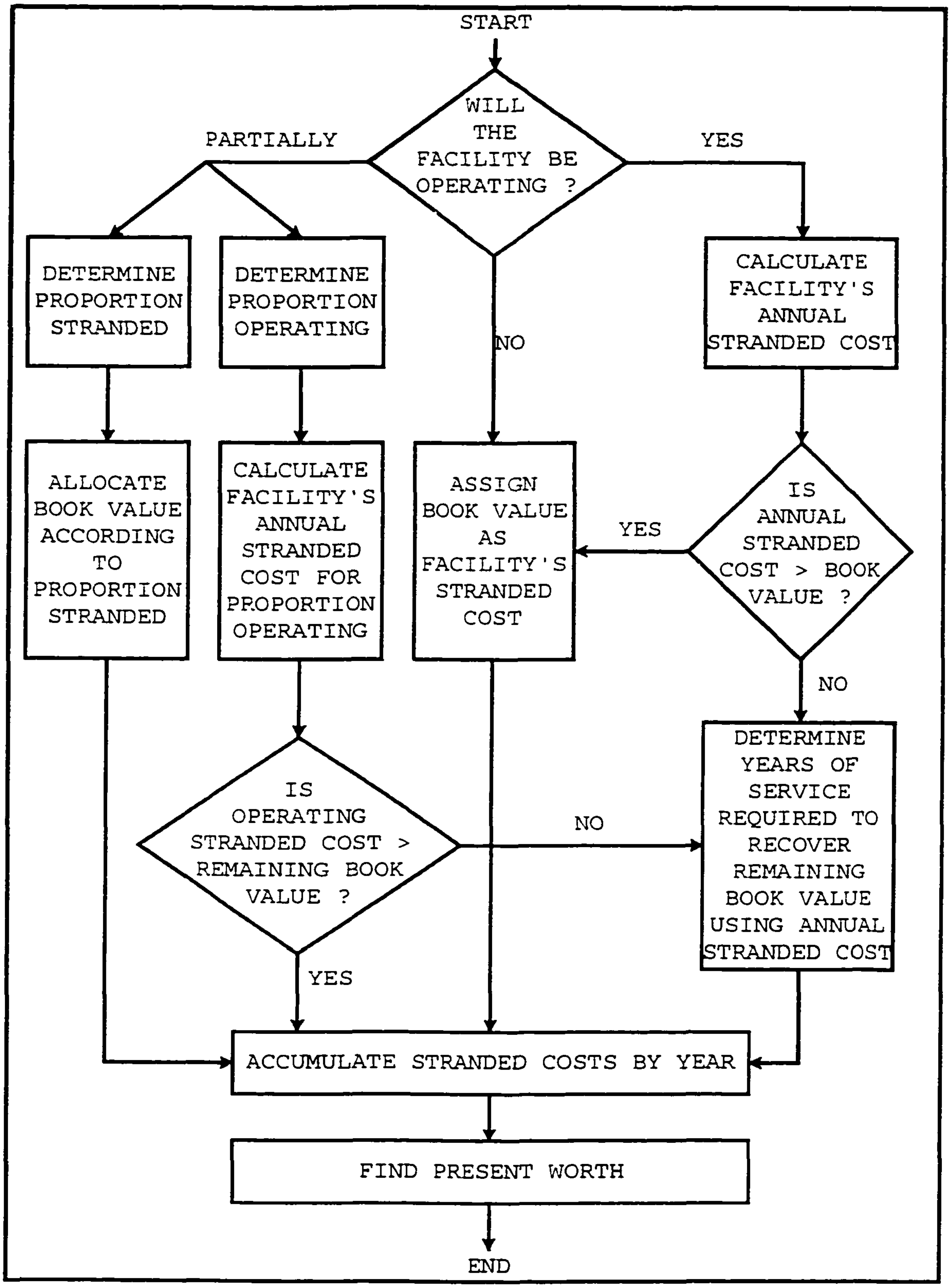


FIGURE 4.1
FLOW CHART FOR IMPLEMENTATION OF THE EMBEDDED COST METHOD

can be mathematically represented on a per KWh basis in the following manner.

$$Expenses = (Fuel\ Cost + Oper.\ \&\ Maint.\ Cost) \div Total\ KWh\ Sold\ . \qquad (4.4)$$

This component can also be thought of as an average variable cost or average production expenses.

4.3.2 Return-on-Capital Component

The rate-of-return on capital is the most controversial component for estimating a generation facility's stranded cost. Some argue that sunk costs are not an issue and, hence, there is no such thing as a stranded cost. But, others argue that investor-owned utility companies have made prudent investments under regulatory discretion under the premise that ratepayers will assume and repay all sunk costs. This component allows for the recovery of such sunk cost debt. The mathematical representation of this component on a per KWh basis is found in Equation 4.5.

$$Return - on - Capital = (R - o - C * BV) \div Total\ KWh\ Sold\ , \qquad (4.5)$$

where,

R-o-C = Regulated Rate-of-Return on Capital, and

BV = Book Value of a Generation Facility.

4.3.3 Depreciation Component

Depreciation expenses are also a component of a generation facility's embedded rate. A straight line approach with a useful life of 40 years is normally assumed. Recently investor-owned utility companies have been employing other accelerated depreciation methods, but

none are included here for consistency purposes. The mathematical representation for straight line depreciation on a per KWh basis is found in Equation 4.6.

$$Depreciation = Original\ Construction\ Cost \div (40 * Total\ KWh\ Sold)\ . \qquad (4.6)$$

4.3.4 Calculating Annual Embedded Stranded Costs

To estimate stranded generation facility costs using the Embedded Cost method, one must first employ the same approach used by the Cost-of-Plant method.

(1) If a facility is not dispatched, it is considered stranded, and its book value is used to indicate its stranded cost.

(2) For partially dispatched facilities, their stranded costs are first allocated on a percentage of book value basis based on the proportion of capacity not dispatched for system peak load to the facility's full load capacity.

Once this part is completed, the estimation of stranded costs for fully and partially dispatched generation facilities must be performed.

To continue, each fully or partially dispatched generation facility's embedded rate must be compared to the power pool's market clearing price. The difference between the embedded rate and the market clearing price is the basis for estimating stranded costs or stranded benefits for operational facilities. An annual estimate of stranded costs can be obtained using the relationship given in Equation 4.7.

$$Annual\ Stranded\ Cost = (ER - MCP) * TAKWh * Div\ , \qquad (4.7)$$

where,

ER = Generation Facility's Embedded Rate,

MCP = System's Market Clearing Price, and

TAKWh = Total Available KWh from a Generation Facility to the power pool.

To estimate the total annual available energy to the pool, certain load characteristics must be identified. One such characteristic is a load factor. It is the ratio of total annual energy served to annual peak load and is common to all control areas (Gönen, 1986). The mathematical representation of a control area's load factor (LF) is found in Equation 4.8.

$$LF = Total\ Annual\ KWh \div (Annual\ Peak\ Load * 8760)\ . \tag{4.8}$$

A slight manipulation of the load factor equation, with the use of a historical load factor, can provide the following estimate for total annual energy consumption.

$$Total\ Annual\ KWh = (Annual\ Peak\ Load * 8760 * LF)\ . \tag{4.9}$$

The annual peak load of a generation facility can be obtained by multiplying its proportion dispatched (Disp %) to meet the power pool's peak demand with its capacity (Cap) as shown in Equation 4.10.

$$Annual\ Peak\ Load = Disp\ \% * Cap\ . \tag{4.10}$$

Finally, total annual available energy can be estimated using Equation 4.11.

$$Total\ Annual\ KWh = (Disp\ \% * Cap * 8760 * LF)\ . \tag{4.11}$$

Once an annual stranded cost figure has been found, there are two possible scenarios that can occur. The numerical figure can either be:

(1) equal to or larger than the facility's book value, or

(2) smaller than the facility's book value (or remaining book value in the case of a partially operational facility).

A decision must then be made from the following two alternatives.

(1) If a facility's annual stranded cost figure is equal to or larger than its book value (or remaining book value), then its book value (or remaining book value) is considered to be its total stranded cost.

(2) If a facility's annual stranded cost figure is smaller than its book value, then the number of years until complete recovery of the book value must be determined.

A simple mathematical expression can be developed to determine the year in question for alternative 2 above. The year is determined by the point of intersection between a generation facility's accumulated book value less depreciation and its total accumulated stranded cost. The mathematical representation of this expression is found in Equation 4.12.

$$[BV - (Ann\ Dep * n)] = (Annual\ Stranded\ Cost * n)\ , \qquad (4.12)$$

where,

Ann Dep = Generation Facility's Annual Depreciation.

Solving for n determines the amount of time in years that it will take to recover the book value of an operational facility.

4.3.5 Total Embedded Stranded Costs

To obtain an estimate of the total and present value of all stranded generation facility costs, each facility

must be evaluated according to the different conditions of dispatch (dispatched or not dispatched) and operation (operating as a stranded benefit or stranded cost). Estimates of annual stranded generation facility costs must be accrued until all stranded book values are recovered.

Once annual stranded costs are identified, a present value can be obtained to reflect current total stranded generation facility costs. A mathematical representation of the present value function for future stranded cost obligations is found in Equation 4.13.

$$Present\ Value = \sum_{k=1}^{n} Annual\ Stranded\ Costs * [1 \div (1+r)^{k}]. \tag{4.13}$$

4.4 Stranded Cost Analysis for the Simple Example

The simple example power system first introduced in Chapter 3 is revisited to demonstrate the use of each cost analysis method. Table 4.1 provides economic dispatch information as well as all system parameters and costs necessary to perform the cost analysis methods.

4.4.1 Cost Analysis Using the Cost-of-Plant Method

For this method, stranded costs for the simple system are determined solely by an economic dispatch criteria. This method evaluates which generation facilities are necessary to meet the power pool's peak demand. If a facility is not dispatched, it is considered "stranded" and its book value is used to indicate its stranded cost. In the case of a fully dispatched generation facility, no book value is applied, and, in the case of a partially stranded facility,

TABLE 4.1
SIMPLE EXAMPLE POWER SYSTEM CHARACTERISTICS

CONTROL AREA #1	CONTROL AREA #2	CONTROL AREA #3
Generation Facility Capacities		
GF_{11} = 100 MW	GF_{21} = 100 MW	GF_{31} = 75 MW
GF_{12} = 150 MW	GF_{22} = 50 MW	GF_{32} = 50 MW
GF_{13} = 50 MW		
Embedded Rates		
$GF_{11} = \$ 6/\text{MWh}$	$GF_{21} = \$11/\text{MWh}$	$GF_{31} = \$17/\text{MWh}$
$GF_{12} = \$13/\text{MWh}$	$GF_{22} = \$12/\text{MWh}$	$GF_{32} = \$20/\text{MWh}$
$GF_{13} = \$ 8/\text{MWh}$		
Book Values		
$GF_{11} = \$ 4,000,000$	$GF_{21} = \$ 400,000$	$GF_{31} = \$1,500,000$
$GF_{12} = \$10,000,000$	$GF_{22} = \$1,000,000$	$GF_{32} = \$ 500,000$
$GF_{13} = \$ 2,000,000$		
Straight Line Depreciation (40 Year Life)		
$GF_{11} = \$150,000$	$GF_{21} = \$ 50,000$	$GF_{31} = \$ 40,000$
$GF_{12} = \$300,000$	$GF_{22} = \$ 30,000$	$GF_{32} = \$ 20,000$
$GF_{13} = \$ 75,000$		
Economic Dispatch		
GF_{11} = 100.0 MW	GF_{21} = 100.0 MW	GF_{31} = 0.0 MW
GF_{12} = 150.0 MW	GF_{22} = 31.2 MW	GF_{32} = 0.0 MW
GF_{13} = 50.0 MW		
System Market Clearing Price		
$GF_{22} = \$9/\text{MWh}$ (Based on Power Pool Production Cost)		
Load Factors		
LF = 0.50 (Assumed for each Control Area)		

its cost is based on the percentage of the proportion of capacity not dispatched to meet the pool's peak demand to the facility's full load capacity.

According to Table 4.1, GF_{31} and GF_{32} are not dispatched and have stranded costs equal to their respective book values. GF_{22} is partially dispatched and has its stranded cost based on the ratio of non-dispatched

capacity to full load capacity. By summing the book value figures for these stranded and partially stranded generation facilities, estimates for the simple system's stranded generation facility costs, according to the Cost-of-Plant method, total $2,376,000.

4.4.2 Cost Analysis Using the Embedded Cost Method

To determine stranded generation facility costs for the simple system by the Embedded Cost method, a comparison between each generation facility's embedded rate and the system's market clearing price must be performed. First, cost analysis results indicate that GF_{31} and GF_{32} are not dispatched and have stranded costs equal to their respective book values. GF_{22} is partially dispatched and has a portion of its stranded cost based on its book value multiplied by the ratio of its non-dispatched capacity to its full load capacity. Next, after computing the annual stranded cost figures for GF_{11} and GF_{13} it was determined that they incur stranded benefits and, therefore, have no recoverable stranded costs. Annual stranded costs were calculated next for GF_{12}, GF_{21}, and GF_{22}. The annual stranded cost figure for GF_{21} is above its book value, so its book value is assigned as its stranded cost. The next step in the process involves the determination of time necessary to recover the book value of GF_{12} and the remaining book value of GF_{22}. GF_{12} takes 3.42 years for full recovery and GF_{22} takes 2.06 years for full recovery. It must be noted that GF_{22} begins to have stranded benefits starting in year 3.

Figure 4.2 summarize the results of the Embedded Cost method of estimating stranded generation facility costs for the simple system.

Table 4.2 is presented to summarize the figures obtained in Figure 4.2 from use of the Embedded Cost method. To conclude the Embedded Cost analysis method for the simple system, the present worth of future stranded generation facility costs are determined. Table 4.2 also provides the equivalent present worth using a 6% discount factor.

4.5 Cost Analysis Summary

This chapter presented the Cost-of-Plant and Embedded Cost methods for cost analysis that can be used to determine stranded generation facility costs. The Cost-of-Plant method accumulates stranded generation costs based solely on the criterion of economic dispatch. Book values are applied to stranded and partially stranded facilities in order to obtain total stranded generation facility costs. The Embedded Cost method takes into consideration generation facilities that are dispatched, but are operating uneconomically because of large sunk costs. In this method, a generation facility's embedded rate is compared to its power pool's market clearing price. Stranded costs accrue for a facility when its embedded rate is above the market clearing price for electricity, and stranded benefits accrue for a facility when its embedded rate is less than the market clearing price. A flow chart of the Embedded Cost

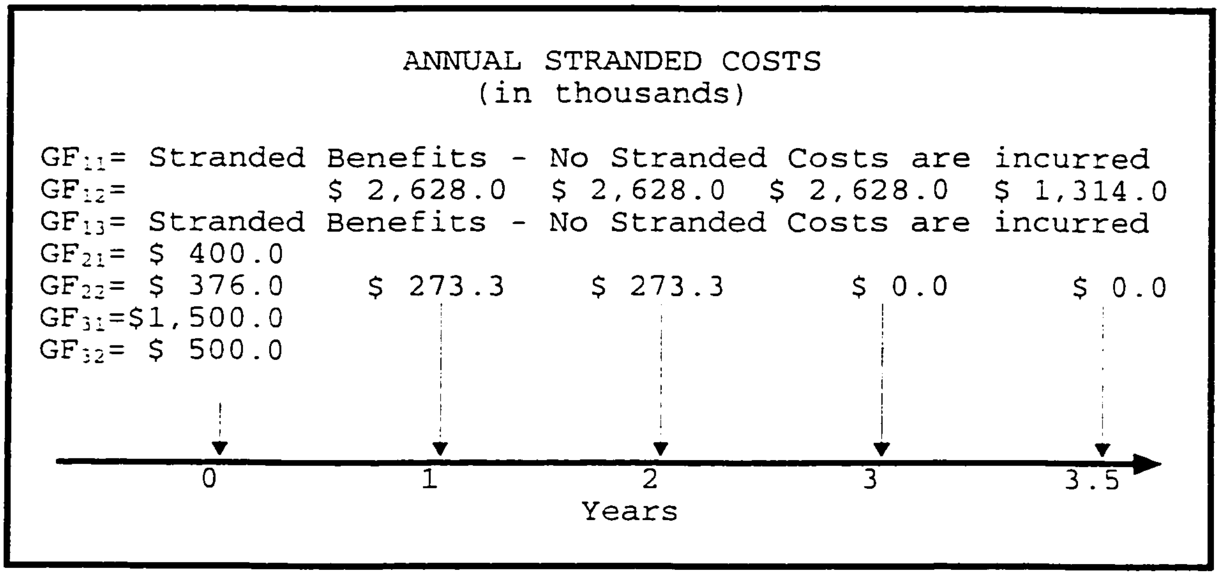


FIGURE 4.2
COST RECOVERY STREAMS FOR THE SIMPLE EXAMPLE POWER SYSTEM

TABLE 4.2
EMBEDDED COST METHOD RESULTS
FOR THE SIMPLE EXAMPLE POWER SYSTEM

YEAR	STRANDED GENERATION FACILITY COST
0	$2,776,000
1	$2,901,312
2	$2,901,312
3	$2,628,000
3.5	$1,314,000
TOTAL	$12,520,624
PRESENT WORTH	$11,373,344

method was presented to provide the reader with a better understanding of how its cost analysis is performed. The chapter concluded with examples of each method using the simple system introduced earlier in Chapter 3.

CHAPTER 5

DATA SOURCES FOR THE LaDEUX MODEL

5.1 Introduction

Chapter five presents data used for the creation of LaDEUX. The Louisiana Public Service Commission is currently considering an option to restructure the state's electric utility industry into its own power pool, thus providing motivation for this state-specific economic dispatch model. The LaDEUX model was developed using these data to determine whether a power pool is feasible, how it will function, and which generation facilities are needed to meet demand. It furthermore adds a significant contribution to determining whether or not restructuring is in the best interest of Louisiana electric power consumers.

The estimation of stranded generation facilities and their costs significantly depends upon the data collected. It is therefore imperative that actual company-specific data be used in the model.

Louisiana-specific data required by LaDEUX have been gathered from a variety of sources covering generation facility production and cost parameters, summer and winter peak demand, and transmission interconnection capacity. In general, transmission networks do not adhere to state boundaries. Therefore, all data relating to generation facilities and transmission interconnections located adjacent to and within the boundaries of Louisiana have been

included since they affect the operation of the state's electric utility system. The most recent data available for generation production, transmission interconnections, and seasonal demand are from 1996. Sources used for all data collected are listed in the following sections of this chapter.

5.2 The Making of LaDEUX

In order to model Louisiana's electric utility system adequately, all generation facilities, transmission interconnections, and control area peak demands must be included. The Southwest Power Pool's (SPP) 1996 Summer and Winter Peak, Base Case, Load Flow Data provided support for formulating the LaDEUX model. Figure 5.1 depicts the Louisiana-specific model in diagram form. SPP load flow data identified 12 control areas operating in Louisiana. Five other external control areas were identified as potential power importers. The SPP data also identified 88 transmission interconnections, 24 qualifying generation facilities in and adjacent to the State, 2 Rural Utility Services generation facilities, 11 municipally-owned generation facilities, 38 investor-owned utility generation facilities in and adjacent to the state, and 2 contracted generation facilities. An illustration of the complete system can be found in Appendix A.

An examination of Figure 5.1 reveals control areas that can be categorized as potential power exporters (having excess generation capacity) while others can be classified

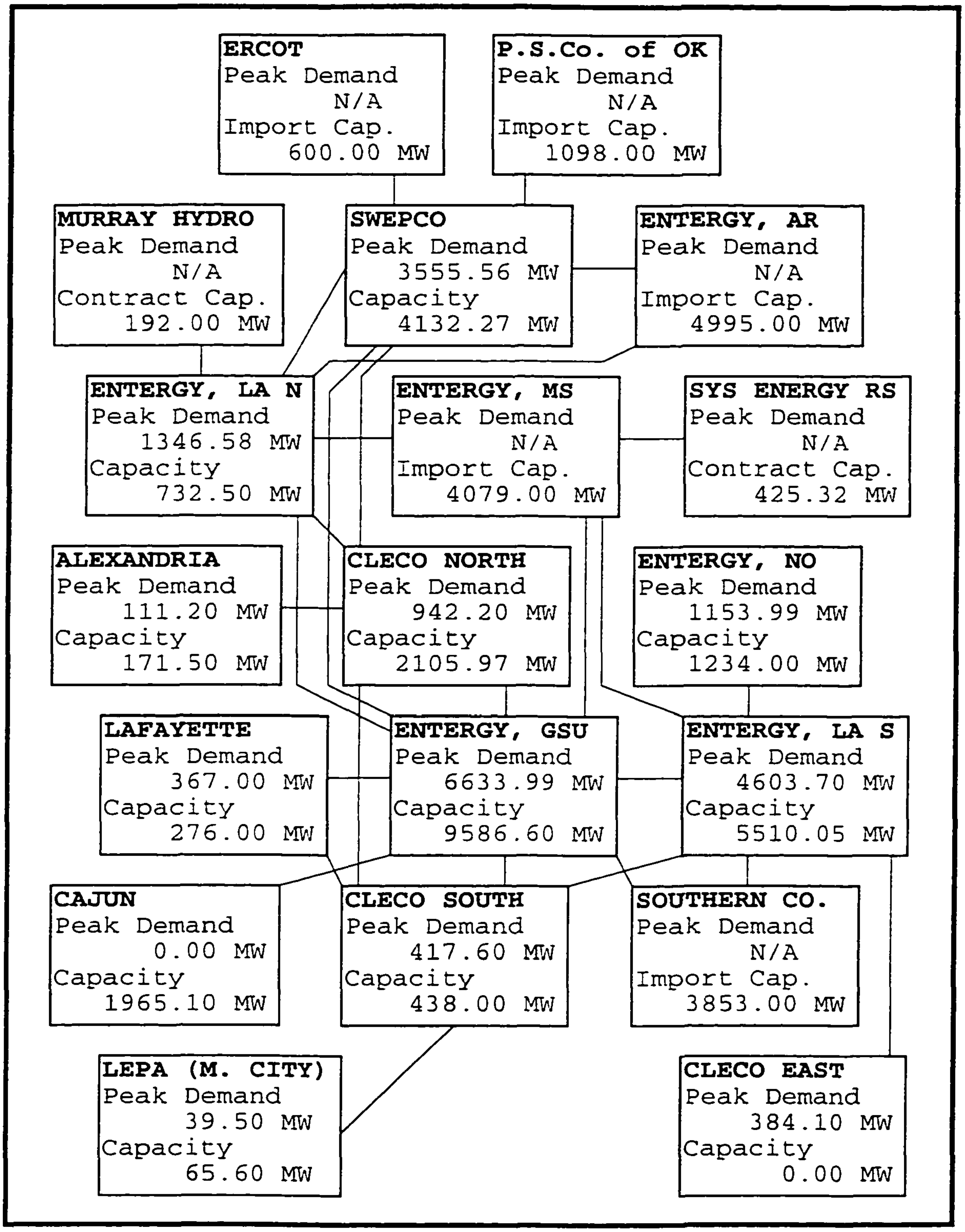


FIGURE 5.1
ONE-LINE LaDEUX MODEL
USING 1996 SPP SUMMER PEAK DEMAND DATA

as potential power importers (having generation capacity shortages). Thus, it is important for the Louisiana system to have sufficient transmission interconnection capacity in place in order to support importing or exporting power transactions. The LaDEUX model determines whether adequate interconnection capacity exists and how it can support a restructured electric utility industry. A list of likely importers and exporters is found in Table 5.1.

TABLE 5.1
COMPANIES LIKELY TO HAVE CAPACITY SURPLUSES OR SHORTAGES

SURPLUS CAPACITIES	SHORTAGE CAPACITIES
City of Alexandria	CLECO
Cajun Electric	(East Operations)
CLECO	Lafayette Utilities
(North Operations)	Entergy
(South Operations)	(LA-North Operations)
System Energy Resources	
Entergy	
(Gulf States Utilities)	
(LA-South Operations)	
(New Orleans)	
LEPA	
Murray Hydro	
SWEPCO	
Entergy*	
(Arkansas)	
(Mississippi)	
Southern Companies*	
(Mississippi Power)	
Public Service Company of Oklahoma*	
ERCOT*	

Note:
* - Indicates a bordering company or power pool expected to have excess generation capacity to export into Louisiana.

5.3 Generation Facility Data

Data sources for power production by investor-owned, municipally-owned, and government-owned generation facilities, as well as qualifying facilities and power importers are presented in this section. All sources are identified along with their contributions toward developing a Louisiana-specific database for modeling the state's electric power system.

Before proceeding to the discussion of the data sources, several caveats must be noted. First, not all 1996 power production data could be obtained. Data for the Alexandria municipally-owned system and several qualifying facilities were not available. For modeling purposes, 1995 data was available in published form and used for the following Qualifying Facilities:

(1) Fina Oil and Chemical,
(2) NISCO,
(3) E.I. Dupont, and
(4) Exxon Chemical.

In addition, only 1994 data was available in published form for the Alexandria municipally-owned system and the following Qualifying Facilities:

(1) Jeanerette Sugar,
(2) Dean Lumber, and
(3) Snider Industries.

The facilities together provide 583.2 MW of generation capacity. In comparison to total system wide available generation capacity of 25,517.92 MW, they account for only 2.29% of all available production capacity. Therefore, it can be concluded that the inability to obtain 1996

production data will not present a significant problem for modeling or analysis.

Second, there are also several generation facilities within the Louisiana system which are jointly owned. Precise locations and costs are necessary for modeling accuracy. For placement purposes, these facilities are positioned within control areas which correspond to their actual geographic location. Average variable costs and fuel costs for these facilities are determined by means of a weighted average, where percent of ownership is used as the weight.

Third, Lafayette Utilities' Doc Bonin generation facility was not 100% operational during 1996. Unit #1 is currently under repair, and its normal capacity of 50 MW is not available. Normal capacity for the facility from Units #1, #2, and #3 is 326 MW. Therefore, the production capability of the generation facility was adjusted to 276 MW for modeling purposes. It is estimated that Unit #1 will be available sometime in late 1998 or early 1999.

Finally, System Energy Resources, Inc.'s Grand Gulf nuclear generation facility is jointly owned by companies both internal and external to the Louisiana system. Of the 1235.25 MW of generation capacity, 90% is contracted to Entergy's Arkansas, Louisiana, Mississippi, and New Orleans companies. Entergy's Louisiana and New Orleans companies account for 14% and 17% of the contracted capacity respectively, making approximately 345 MW of capacity directly available to Louisiana consumers.

Data collected for all generation facilities can be found in Appendix B and are listed by control area. Average variable and fuel cost coefficients specific to model formulation (AC_{jx}, ACC_{jx}, ACI_{jx}, FC_{jx}, FCC_{jx}, and FCI_{jx}) are included. Appendix B.1 contains ranked values for average variable cost of production by facility under the column heading *TOTAL AVERAGE VARIABLE COST*. Appendix B.2 contains ranked values for fuel production cost by facility under the column heading *FUEL COST*. Capacities for each type of generation facility (GF_{jx} ,CGF_{jx} , and IGF_{jx}) can also be found in either entry of Appendix B. Corresponding values are located under the column heading *MW CAPACITY*.

5.3.1 Investor-Owned

Data for investor-owned electric power generation facilities (CLECO, Entergy Gulf States, Entergy Louisiana, Entergy New Orleans, SWEPCO, and System Energy Resources) were collected from *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others* for all companies. The filing of this form is required by FERC (Federal Energy Regulatory Commission) for each investor-owned electric utility. The form contains important modeling parameters such as facility name, year originally constructed, total installed capacity, primary fuel type, total production expenses per net KWh, average cost of fuel burned per KWh, net generation, etc., but does not contain marginal production costs. Investor-owned electric utility companies

consider marginal production costs proprietary information and do not release such information to the public.

Capital costs, book values, and sales data for investor-owned electric utility companies (including the portion of Cajun Electric Power Cooperative that is investor-owned) were collected from various reports. Both cost analysis methods presented in Chapter 4 require the use of such data. Construction cost data were obtained from the Utility Data Institute. Report UDI-2053-94, *Electric Utility Power Plant Construction Costs,* lists construction costs for conventional steam turbine, simple-cycle gas turbine, combined-cycle (steam turbine and gas turbine), hydroelectric, and internal combustion power plants. Book values, sales data, control area load factors, and Louisiana diversification factors were all obtained or interpreted from *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others.*

Data concerning a generation facility's cost-of-plant (book value), original construction cost, and total energy sold is located in Appendix B.3. under the column headings *COST-OF-PLANT, ORG. CONS. COST* and *TOTAL KWH SOLD* respectively. In addition, Appendix B.3 includes a load factor and Louisiana diversification factor for each control area under the column headings *LOAD FACTOR* and *LOUISIANA DIV. FACTOR* respectively.

5.3.2 Municipally-Owned

Data for municipally-owned electric power generation facilities were collected from a number of different sources. Municipally-owned generation facilities are not required to report or publish detailed system statistics or costs, making data collection a difficult task. To begin the task, the United States Department of Energy's Energy Information Administration report DOE/EIA-0437 entitled *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1994* was consulted. The report contains information important to the identification of several Louisiana municipally-owned generation facilities (Alexandria, Houma, Lafayette, LEPA, Morgan City, Natchitoches, and Ruston), but its cost information is considered outdated for modeling purposes.

To obtain updated production expenses and fuel costs, public disclosure requests for 1996 data were made to all municipally-owned generation facilities (Alexandria, Houma, Lafayette, LEPA, Minden, Morgan City, Natchitoches, New Roads, Plaquemine, Opelousas, Rayne, and Ruston) through the Louisiana Public Service Commission Legal Department. Data requests included modeling parameters such as: year originally constructed, book value of plant, accumulated depreciation through 1996, total installed capacity, primary fuel type, total operation expenses, total maintenance expenses, total fuel expenses, and total sales. Since investor-owned generation facilities would not disclose

their marginal production costs, it was not requested from the municipally-owned facilities.

Alexandria and Opelousas were the only municipally-owned facilities that did not respond to the disclosure requests. Opelousas is a mothballed facility, so its data are not of great concern, but Alexandria is a functional facility. For modeling purposes data necessary to represent the facility were taken from *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1994*.

5.3.3 Government-Owned

Data for the only government-owned electric power generation facility (Cajun Electric Power Cooperative) were collected from the *United States Department of Agriculture's Rural Utility Services: RUS Form 12*. The filing of this form is required by Rural Utility Services (RUS) for all government-owned electric utilities. The form contains important modeling parameters such as facility name, operator, total installed capacity, fuel type, total production expenses, average cost of fuel burned per KWh net generation, etc., but does not contain marginal production costs.

5.3.4 Qualifying Facilities

Data for Qualifying Facility (QF) generation were collected from the Louisiana Department of Natural Resources, Technology Assessment Division's *Non Utility Generation of Electricity in Louisiana* report. The report contains nonutility generation data consisting of QF status,

generation capacity, fuel type, and service arrangement (interconnected, utility backup or stand alone) for facilities affecting Louisiana's electric utility system. In addition, the report lists buy-back rates from each nonutility generation facility's host investor-owned electric utility. The rates are presented in month-by-month and yearly average format. The rates are assumed to cover costs for production and fuel. If not, there would be no incentive for a nonutility generator to sell power back to its host electric utility.

5.3.5 Power Importers

Data for companies or power pools importing power into Louisiana were collected from production cost reports published by the Utility Data Institute. Reports UDI-2011-97 and UDI-2023-98 list production costs for operating steam-electric plants, gas turbines, and combined-cycle power plants respectfully.

An overall production cost for each potential importer was determined by taking a weighted average of production costs of all potential importing generation facilities. Each importer's peak demand was used as the weight for the cost calculation. Weighted average variable as well as fuel production cost data were determined and can be found in Appendix B.1 and B.2 respectively. Each potential importer's weighted average variable and fuel production costs are highlighted in bold letters under the column headings *TOTAL AVERAGE VARIABLE COST* and *FUEL COST*. These cost figures were

used with the presumption that an importer has not only sufficient transmission interconnection capacity into Louisiana but also excess power production capacity.

For modeling purposes, power imports are treated as variables. Given a bordering company's generation, interconnection capacity, and power pool bid, the LaDEUX model can determine the state's market clearing price for power and amount of imported power necessary to meet summer or winter peak demand.

5.4 Transmission Interconnection Data

Data for transmission interconnections were obtained from the Southwest Power Pool's *1996 Summer Peak, Base Case Load Flow Model*. The model is configured as a series of demand nodes (transmission substations) interconnected by arcs (transmission lines). Each node has its own identification number containing company, area and zone information. Arcs are identified by their respective "From" and "To" nodes.

The load flow model contains information for all transmission lines rated 69 kV and above in the power pool. It contains data consisting of transmission line capacity ratings (for both normal and emergency conditions), line-to-line voltage, and line impedance. For conservative modeling purposes, normal operation capacity data were used for all interconnecting lines.

An overall postage stamp transmission cost was calculated for Louisiana's electric power system. It is a

weighted average of average transmission provider costs. Each provider's summer peak demand is used as the weight for the postage rate calculation.

Transmission interconnection data are available in Appendix C. It contains a weighted average postage rate cost coefficient (TC) and interconnection parameters for capacity ($TCAP_{jky}$), line-to-line voltage (V_{jky}), and line impedance (Z_{jky}). A 3-phase, 100 MVA base was used to obtain true impedance parameters for all transmission interconnections. The weighted average postage rate value is highlighted in Appendix C.1. System parameters for interconnection capacity, voltage, and impedance are indicated under the column headings *MW CAP.*, *V 1-1,* and *IMPEDANCE* in Appendix C.2.

5.5 Summer and Winter Peak Demand Data

Data for summer and winter peak demand were extracted from the Southwest Power Pool's *1996 Summer Peak and Winter Peak, Base Case Load Flow Models*. The Southwest Power Pool's models indicate seasonal peak demand for each transmission substation within the pool. Transmission substations are identified by utility company, area, and zone. Their respective demands indicate total seasonal control area peak demand when summed together.

For reliability reasons, spinning reserve requirements are included with the seasonal peak demand data. The Southwest Power Pool's seasonal peak demand figures have been increased 15% to include spinning reserve generation

facilities economically dispatched by LaDEUX. Scherer (1976) incorporates this same spinning reserve requirement in his *ex ante* approach for estimating peak and off-peak marginal costs for an electric power system. These facilities provide consumers with a level of service they expect from the industry.

Seasonal peak demand affects the identification of stranded generation facilities and their costs. As demand increases from winter to summer, more facilities are dispatched to increase power production. The increase in demand strands fewer generation facilities and decreases stranded generation facility costs. But, as demand decreases from summer to winter, fewer facilities are needed. The decrease in demand strands more facilities and increases stranded generation facility costs.

Data collected for summer and winter peak demand with spinning reserve requirements are listed in Appendix D. Specific peak demand parameters for summer (SPD_j) and winter (WPD_j) are included. Appendix D.1 contains values for summer peak demand whereas Appendix D.2 contains values for winter peak demand for each control area under the column heading *TOTAL PEAK DEMAND IN MW*.

5.6 Data Sources Summary

Details concerning the Louisiana electric utility system were presented in this chapter. This information is the basis for creating the LaDEUX model for estimating stranded generation facilities and their costs.

All generation facility, transmission interconnection, and summer and winter peak demand parameters and cost sources were presented. Investor-owned, municipally-owned, government-owned, and qualifying facility sources furnished data consisting mainly of fuel type, capacity, and production costs. Production data for power importers consists only of capacity and costs. In addition, a few insignificant inconsistencies in the data were presented and explained.

Transmission interconnections are vital for wheeling to be successful. Sufficient interconnection capacity provides the infrastructure to move electric power from deregulated generation facilities to wholesale and/or retail customers. The transmission interconnection data found in this chapter includes capacity, line-to-line voltage, impedance, and a system-wide weighted average for transmission interconnection costs.

Stranded generation facility estimates are affected by system peak demands. More facilities are needed to meet summer peak demand while fewer facilities are needed to meet winter peak demand. The summer and winter peak demand figures presented in this chapter contain the losses incurred while transmitting and distributing electric power within a control area. Spinning reserves were included in excess of peak demand figures to estimate which generation facilities are needed to satisfy consumer demand, system reliability, and security requirements.

CHAPTER 6

EXPERIMENTATION RESULTS

6.1 Introduction

The research thus far has identified generation and transmission interconnection parameters, supplied system cost data, developed an economic dispatch model, and presented two cost analysis methods for determining stranded generation facility costs. In this chapter, the data, economic dispatch model, and cost analysis methods come together for experimental analysis of Louisiana's electric utility system. Stranded generation facilities are identified, market clearing prices are determined, and stranded generation facility costs are estimated according to experimental design factors of summer or winter peak demand, an open or closed system for power imports, and bundled or unbundled transmission interconnection costs.

Generalized economic dispatching results are discussed in Section 6.2; complete economic dispatching results are presented in Appendix E. The effects of power imports on Louisiana's electric utility system are discussed in Section 6.3. Economic dispatch results are then used in conjunction with each cost analysis method to determine boundary cost estimates for stranded and uneconomically operating generation facility costs. Results and comparisons from the Cost-of-Plant and Embedded Cost estimation methods are found in Section 6.4. Some interesting economic dispatching

discoveries are presented in Section 6.5, and the chapter concludes with a summary of the two stage estimation methodology for stranded generation facility costs in Section 6.6.

6.2 Economic Dispatching Results

In Chapter 3, sixteen experiments were designed to test the sensitivities of solution to the LaDEUX model. Variations of peak demand, power import factors, and transmission interconnection costs were used for experimentation purposes to study the dispatching of generation facilities as well as production cost responses to the model. Complete economic dispatch solutions from LaDEUX for Louisiana's generation facilities can be found in Appendix E.

Experimental solutions to the LaDEUX model provide results which indicate how Louisiana's generation facilities can be categorized into three classes. These classes are listed and briefly described as follows.

(1) ***Must-run facilities***, otherwise known as base-load facilities, are facilities that are dispatched by LaDEUX in all sixteen experiments. These facilities can be found in Tables 6.1 and 6.2.

(2) ***Transitional facilities***, better known as intermediate, peaking, and spinning reserve facilities, are regulated facilities dispatched by LaDEUX to meet peak demand as it cycles transitionally from base-load to peak-load. These facilities can be found in Tables 6.3 and 6.4.

(3) ***Stranded facilities***, or non-dispatched facilities, are facilities that are never dispatched in any of the sixteen experiments by LaDEUX. These facilities can be found in Tables 6.5 and 6.6.

Production parameters vary greatly between the above classes. Thus, each class provides unique information for determining stranded generation facilities and estimating their costs. Descriptions of each are found in the following subsections.

Traditional economic dispatch commits generation facilities for service according to lowest production costs only. It is worthy to note that although the average variable and fuel production costs of Tables 6.1 through 6.6 are ranked according to $/MWh, generation facilities were not necessarily selected in this order for inclusion in all experimental optimal solutions. The technical transmission interconnection power flow constraints associated with line capacity, losses, and costs, in some instances, required the dispatching of higher cost facilities. In such situations, load pockets are likely to arise. Load pockets are areas lacking the resources necessary to "wheel in" low-cost power, and provide for discontinuities in supply curves.

6.2.1 Must-Run Facilities

Tables 6.1 and 6.2 indicate Louisiana's must-run facilities according to average variable and fuel production cost dispatching (AVC Dispatch and FC Dispatch) respectively. These are facilities that are allocated to meet Louisiana's base demand and are dispatched to full capacity in all LaDEUX experiments.

Both of these groups contain a large number of qualifying facilities. Although the total amount of power

TABLE 6.1
MUST-RUN FACILITIES UNDER AN
AVERAGE VARIABLE COST (AVC) DISPATCHING PRIORITY

PLANT NAME	QF/HOST	ST	FUEL TYPE	AVC DISPATCH	MW CAPACITY
Minden	Minden	LA	Gas	$7.50/MWh	34.50
Fina Oil	QF/Entergy	TX	Gas	14.00	37.00
NISCO	QF/Entergy	LA	Gas	15.70	200.00
E.I. Dupont	QF/Entergy	TX	Gas	16.50	85.00
Exxon Chem.	QF/Entergy	LA	Gas	17.60	84.00
Cogen Power	QF/Entergy	TX	Heat	18.50	5.00
IMC-Agrico	QF/Entergy	LA	Slph	19.00	22.00
Calciner	QF/Entergy	LA	Coke	19.10	27.00
Formosa	QF/Entergy	LA	Gas	19.10	46.00
Doc Bonin	LAFA	LA	Gas	19.35	276.00
Engr. Carbons	QF/Entergy	TX	Heat	19.80	10.00
Vulcan Chem.	QF/Entergy	LA	Gas	20.10	108.00
Grand Gulf	S.E.R.	MS	Nclr	20.20	345.00
Huntsman	QF/Entergy	TX	Gas	20.30	72.00
B.P. Oil	QF/Entergy	LA	RGas	21.20	19.15
Clark Ref.	QF/Entergy	TX	Gas	21.30	84.80
Air Liquide	QF/Entergy	TX	Gas	21.40	36.00
Jeanerette	QF/CLECO	LA	BGas	21.90	0.10
Waterford 3	Entergy	LA	Nclr	22.10	1,200.00
Dow Chem.	QF/Entergy	LA	Gas	22.20	670.00
Bordon Chem.	QF/Entergy	LA	Gas	22.40	91.50
James River	QF/Entergy	LA	Pulp	22.40	57.50
Star Entp.	QF/Entergy	TX	Gas	22.90	164.00
Air Products	QF/Entergy	LA	Gas	23.70	23.00
Pirkey 8	SWEPCO	TX	Lgnt	24.60	619.38
Big Cajun 2	Cajun	LA	Coal	24.76	1,735.10
Dean Lumber	QF/SWEPCO	TX	Wood	25.70	0.60
Snider Ind.	QF/SWEPCO	TX	Wood	25.90	5.00
Rodemacher 2	CLECO	LA	Coal	26.00	558.00
River Bend 1	Entergy	LA	Nclr	28.68	1,022.30
BASF	QF/Entergy	LA	Gas	28.70	36.60
Agrielectric	QF/Entergy	LA	Rice	34.90	12.50
Dolet Hills	CLECO	LA	Lgnt	35.40	650.37
R.S. Nelson 6	Entergy	LA	Coal	40.20	430.00
Natchitoches	Natch.	LA	Gas	40.21	48.00
Welsh 6	SWEPCO	TX	Coal	41.90	1,674.00
Morgan City	Mrgn. City	LA	Gas	51.73	65.60
Big Cajun 1	Cajun	LA	Gas	52.67	230.00
Teche	CLECO	LA	Gas	53.10	427.90
Lewis Creek	SWEPCO	TX	Gas	53.90	544.00
TOTAL CAPACITY					**11,756.90**

TABLE 6.2
MUST-RUN FACILITIES UNDER A
FUEL COST (FC) DISPATCHING PRIORITY

PLANT NAME	QF/HOST	ST	FUEL TYPE	FC DISPATCH	MW CAPACITY
Murray Hydro	QF/Entergy	LA	None	$0.00/MWh	192.00
Minden	Minden	LA	Gas	3.33	34.50
Grand Gulf	S.E.R.	MS	Nclr	5.10	345.00
Doc Bonin	LAFA	LA	Gas	5.76	276.00
Waterford 3	Entergy	LA	Nclr	6.00	1,200.00
River Bend 1	Entergy	LA	Nclr	6.74	1,022.30
Pirkey 8	SWEPCO	TX	Lgnt	11.00	619.38
Fina Oil	QF/Entergy	TX	Gas	14.00	37.00
Dolet Hills	CLECO	LA	Lgnt	15.50	650.37
NISCO	QF/Entergy	LA	Gas	15.70	200.00
E.I. Dupont	QF/Entergy	TX	Gas	16.50	85.00
P.S. Nelson 6	Entergy	LA	Coal	17.00	430.00
Rodemacher 2	CLECO	LA	Coal	17.38	558.00
Exxon Chem.	QF/Entergy	LA	Gas	17.60	84.00
Big Cajun 2	Cajun	LA	Coal	17.95	1,735.10
Cogen Power	QF/Entergy	TX	Heat	18.50	5.00
IMC-Agrico	QF/Entergy	LA	Slph	19.00	22.00
Formosa	QF/Entergy	LA	Gas	19.10	46.00
Calciner Ind.	QF/Entergy	LA	Coke	19.10	27.00
Engr. Carbons	QF/Entergy	TX	Heat	19.80	10.00
Vulcan Chem.	QF/Entergy	LA	Gas	20.10	108.00
Huntsman Corp.	QF/Entergy	TX	Gas	20.30	72.00
Welsh 6	SWEPCO	TX	Coal	21.00	1,674.00
B.P. Oil	QF/Entergy	LA	RGas	21.20	19.15
Clark Refining	QF/Entergy	TX	Gas	21.30	84.80
Air Liquide	QF/Entergy	TX	Gas	21.40	36.00
Jeanerette	QF/CLECO	LA	BGas	21.90	0.10
Dow Chem.	QF/Entergy	LA	Gas	22.20	670.00
Borden Chem.	QF/Entergy	LA	Gas	22.40	91.50
James River	QF/Entergy	LA	Pulp	22.40	57.50
Star Entp.	QF/Entergy	TX	Gas	22.90	164.00
Air Products	QF/Entergy	LA	Gas	23.70	23.00
TOTAL CAPACITY					**10,578.70**

produced by these facilities is relatively small (1,293.75 MW out of 11,756.9 MW total for Table 6.1 and 2,034.05 MW out of 10,578.7 MW total for Table 6.2), they are dispatched first because they are the most cost effective to operate.

Traditional electric utility economic dispatch involved classifying and dispatching generation facilities according to size, type, and production costs concurrently. In the past, nuclear and large fossil-fired facilities made up an electric utility's must-run classification. These units typically have capacities of considerable size and require constant output settings and steam system thermal balance. With the onset of deregulation, this method of classifying generation facilities is in jeopardy. As more inexpensive qualifying facilities enter power pools, they are displacing traditional, capital intensive facilities from their must-run classification.

In Louisiana's case, all three nuclear generation facilities maintained their status as must-run facilities, but very few of the state's large fossil facilities managed to keep their must-run status. They were replaced by qualifying facilities and displaced into the transitional category which is certain to initiate requests for substantial stranded and uneconomically dispatched generation facility cost recovery by investor-owned utilities when deregulation becomes a reality.

6.2.2 Transitional Facilities

Tables 6.3 and 6.4 indicate Louisiana's transitional facilities and are identified according to average variable and fuel production cost dispatching (AVC Dispatch and FC Dispatch) respectively. They are allocated on an incremental basis to meet Louisiana's cyclical peak demand while taking into consideration all transmission interconnection constraints. Some are dispatched to full capacity while others are not. The last facility dispatched from this group determines the market clearing price for each experiment executed by LaDEUX. Appendix E can be referenced for complete information concerning generation facility dispatch proportions for all sixteen LaDEUX experiments.

TABLE 6.3
TRANSITIONAL FACILITIES UNDER AN
AVERAGE VARIABLE COST (AVC) DISPATCHING PRIORITY

PLANT NAME	QF/HOST	ST	FUEL TYPE	AVC DISPATCH	MW CAPACITY
Sabine	Entergy	TX	Gas	$55.00/MWh	2,051.00
Wilkes 5	SWEPCO	TX	Gas	55.70	881.52
R.S. Nelson 3&4	Entergy	LA	Gas	59.80	755.00
Arsenal Hill 1	SWEPCO	LA	Gas	60.60	125.00
Rodemacher 1	CLECO	LA	Gas	62.10	445.50
Murray Hydro	QF/Entergy	LA	None	63.80	192.00
9 Mile Point	Entergy	LA	Gas	64.20	1,917.00
Knox Lee 3	SWEPCO	TX	Gas	66.50	499.50
Little Gypsy	Entergy	LA	Gas	66.80	1,251.00
Willow Glen	Entergy	LA	Gas	67.10	2,178.00
Michoud	Entergy	LA	Gas	69.40	959.00
Sterlington	Entergy	LA	Gas	79.00	480.00
TOTAL CAPACITY					**11,734.52**

TABLE 6.4
TRANSITIONAL FACILITIES UNDER A
FUEL COST (FC) DISPATCHING PRIORITY

PLANT NAME	**QF/HOST**	**ST**	**FUEL TYPE**	**FC DISPATCH**	**MW CAPACITY**
Arsenal Hill 1	SWEPCO	LA	Gas	$25.00/MWh	125.00
Dean Lumber	QF/SWEPCO	TX	Wood	25.70	0.60
Snider Ind.	QF/SWEPCO	TX	Wood	25.90	5.00
Lewis Creek	Entergy	TX	Gas	26.00	544.00
Sabine	Entergy	TX	Gas	27.00	2,051.00
Wilkes 5	SWEPCO	TX	Gas	27.00	881.52
BASF	QF/Entergy	LA	Gas	28.70	36.60
R.S. Nelson 3&4	Entergy	LA	Gas	29.00	755.00
Ruston	Ruston	LA	Gas	29.62	81.00
Rodemacher 1	CLECO	LA	Gas	30.00	445.50
9 Mile Point	Entergy	LA	Gas	31.00	1,917.00
Big Cajun 1	Cajun	LA	Gas	31.66	230.00
Knox Lee 3	SWEPCO	TX	Gas	32.00	499.50
Michoud	Entergy	LA	Gas	32.00	959.00
Willow Glen	Entergy	LA	Gas	32.00	2,178.00
Little Gypsy	Entergy	LA	Gas	32.00	1,251.00
Teche	CLECO	LA	Gas	32.10	427.90
Sterlington	Entergy	LA	Gas	33.00	480.00
Coughlin	CLECO	LA	Gas	33.00	368.10
Hunter	Alexandria	LA	Gas	34.00	171.50
Agrielectric	QF/Entergy	LA	Rice	34.90	12.50
TOTAL CAPACITY					**13,419.72**

Similar to the must-run facility classification, traditional electric utility economic dispatch involved dispatching transitional generation facilities according to size, type, and production costs concurrently. Facilities of this category usually include small fossil, hydroelectric, and gas turbine generators. With the onset of deregulation, generation facilities previously classified as must-run, base-load facilities are becoming transitional facilities. According to the results of this research, large investor-

owned fossil facilities make up the majority of this classification. These facilities were originally planned and constructed to take advantage of economies of scale in the industry. This situation is problematic for the industry since the economic dispatching of these facilities under deregulated conditions is forcing the facilities to operate uneconomically. Therefore, stranded costs are accrued and electric utilities will also be asking for their recovery once the industry is restructured.

6.2.3 Stranded Facilities

Tables 6.5 and 6.6 indicate Louisiana's completely stranded generation facilities according to average variable and fuel production cost dispatching (AVC Dispatch and FC Dispatch) respectively. These facilities are never allocated to meet peak demand by the LaDEUX model. Stranded costs from this group accumulate from facilities which have not been fully depreciated and electric utilities are certain to request their recovery when deregulation becomes a reality.

It should be noted that several of these fully stranded facilities have already been placed in long term storage. According to Maloney et al. (1996b), regulated firms have historically had incentives to idle generation facilities that are still economical to operate. Furthermore, Maloney argues some of these may still be valuable in a competitive market and produce net positive cash flows. If Maloney's argument is correct and these stored facilities are fully depreciated, a move to

TABLE 6.5
STRANDED FACILITIES UNDER AN
AVERAGE VARIABLE COST (AVC) DISPATCHING PRIORITY

PLANT NAME	QF/HOST	ST	FUEL TYPE	AVC DISPATCH	MW CAPACITY
Houma	Houma	LA	Gas	$72.51/MWh	98.00
Waterford 1&2	Entergy	LA	Gas	74.70	891.00
Coughlin	CLECO	LA	Gas	78.50	368.10
Ruston	Ruston	LA	Gas	81.93	81.00
Lieberman 2	SWEPCO	LA	Gas	86.10	277.27
Lone Star 4	SWEPCO	TX	Gas	95.90	50.00
Hunter	Alexandria	LA	Gas	108.00	171.50
A.B. Pat. (Steam)	Entergy	LA	Oil	214.40	16.00
Buras	Entergy	LA	Gas	218.80	21.00
Rayne	Rayne	LA	Gas	329.34	2.50
Plaquemine	LEPA	LA	Gas	339.13	42.90
New Roads	New Roads	LA	Gas	3286.19	7.60
Opelousas	Opelousas	LA	Gas	In Storage	36.00
Market Street	Entergy	LA	N/A	In Storage	103.00
A.B. Pat. (Gas)	Entergy	LA	Gas	In Storage	133.00
Thibodaux 9	Entergy	LA	Gas	In Storage	21.00
Franklin	CLECO	LA	Gas	In Storage	10.00
Monroe	Entergy	LA	Gas	In Storage	137.00
LA St. #1	Entergy	LA	Gas	In Storage	148.00
LA St. #1 Unit 4A	Entergy	LA	N/A	In Storage	129.00
LA St. #2	Entergy	LA	Gas	In Storage	175.00
Neches	Entergy	TX	N/A	In Storage	269.00
Firestone	QF/Entergy	LA	Gas	Not Connected	0.30
Citgo	QF/Entergy	LA	Gas	Not Connected	75.00
TOTAL CAPACITY					**3,263.17**

TABLE 6.6
STRANDED FACILITIES UNDER A
FUEL COST (FC) DISPATCHING PRIORITY

PLANT NAME	QF/HOST	ST	FUEL TYPE	FC DISPATCH	MW CAPACITY
Waterford 1&2	Entergy	LA	Gas	$35.00/MWh	891.00
Houma	Houma	LA	Gas	38.69	98.00
Lieberman 2	SWEPCO	LA	Gas	39.00	277.27
Natchitoches	Natch.	LA	Gas	40.21	48.00
Morgan City	Mrgn. City	LA	Gas	41.45	65.60
Lone Star 4	SWEPCO	TX	Gas	42.00	50.00
New Roads	New Roads	LA	Gas	49.18	7.60
Rayne	Rayne	LA	Gas	65.17	2.50
Plaquemine	LEPA	LA	Gas	79.53	42.90
Buras	Entergy	LA	Gas	90.00	21.00
A.B. Pat. (Steam)	Entergy	LA	Oil	107.00	16.00
Opelousas	Opelousas	LA	Gas	In Storage	36.00
Market Street	Entergy	LA	N/A	In Storage	103.00
A.B. Pat. (Gas)	Entergy	LA	Gas	In Storage	133.00
Thibodaux 9	Entergy	LA	Gas	In Storage	21.00
Franklin	CLECO	LA	Gas	In Storage	10.00
Monroe	Entergy	LA	Gas	In Storage	137.00
LA St. #1	Entergy	LA	Gas	In Storage	148.00
LA St. #1 Unit 4A	Entergy	LA	N/A	In Storage	129.00
LA St. #2	Entergy	LA	Gas	In Storage	175.00
Neches	Entergy	TX	N/A	In Storage	269.00
Firestone	QF/Entergy	LA	Gas	Not Connected	0.30
Citgo	QF/Entergy	LA	Gas	Not Connected	75.00
TOTAL CAPACITY					**2,756.17**

competition and modest capital investment could restore them to useful life and provide investor-owned utilities production benefits with which they may exercise market power.

It is worthy to note that Tables 6.3 and 6.5 indicate a discontinuity in generation supply. For instance, Entergy's Sterlington facility is listed as a transitional facility whereas three south Louisiana facilities—Houma, Waterford 1&2, and Coughlin—are listed as stranded. All three of these facilities are less expensive to operate per MWh than Sterlington, but in experiment #7 (experimental factors: average variable production cost, summer peak demand, a closed system for imports, and bundled transmission costs), transmission interconnection constraints of costs and losses keep them from wheeling power to Entergy Louisiana's northern customers.

These supply curve discontinuities are an important discovery uncovered by LaDEUX's economic dispatch results. In fact, it should be noted that many experimental results found in Appendix E exhibit this same discontinuous generation supply phenomenon. The finding illustrates that a pure study of Louisiana's generation production capabilities without transmission interconnection constraints is inadequate for assessing stranded generation facility costs. This finding is discussed in greater detail in Section 6.5.

6.3 The Effects of Power Imports

In 8 of the 16 LaDEUX experiments, an open system for power imports was modeled to study the cost effects of wheeling less expensive power to Louisiana's electric utility customers. For modeling purposes, power imports were treated as variables. Given a bordering utility's generation facilities, transmission interconnection capacity, and generation production costs on a weighted average basis, the LaDEUX model determined the amount of power imports necessary to meet peak demand under certain economic and technical conditions and the Louisiana system's market clearing price for power. The stranding of local generation facilities is the most important side effect encountered when importing economically produced power. Tables 6.7 and 6.8 indicate the total anticipated amount of economically produced power to be imported into the Louisiana system after restructuring becomes a reality.

Several interesting results were discovered concerning Louisiana's neighboring utilities. First, to the west, ERCOT (Texas Utilities Electric Company) produces inexpensive power on both an average variable and fuel cost basis but has only one 600 MW transmission interconnection into the SWEPCO system. In addition to this constraint, it is also limited in competing on an open power market for interstate commerce reasons. In all eight open system experiments, the lone transmission interconnection was loaded to capacity, indicating that transmission interconnection costs and

TABLE 6.7
ANTICIPATED TOTAL POWER IMPORTS IN MW
ACCORDING TO AVERAGE VARIABLE PRODUCTION COST DISPATCHING

EXP #	ERCOT	ENTERGY ARKANSAS	SOUTHERN CO.	PUBLIC SERVICE CO. OF OKLAHOMA	ENTERGY MISSISSIPPI
	SUMMER PEAK DEMAND WITHOUT TRANSMISSION COSTS				
1	600	2055	2055	0	0
	WINTER PEAK DEMAND WITHOUT TRANSMISSION COSTS				
2	600	714	1621	0	0
	SUMMER PEAK DEMAND WITH TRANSMISSION COSTS				
5	600	1750	1933	0	0
	WINTER PEAK DEMAND WITH TRANSMISSION COSTS				
6	600	646	1538	0	0

TABLE 6.8
ANTICIPATED TOTAL POWER IMPORTS IN MW
ACCORDING TO FUEL PRODUCTION COST DISPATCHING

EXP #	ERCOT	ENTERGY ARKANSAS	SOUTHERN CO.	PUBLIC SERVICE CO. OF OKLAHOMA	ENTERGY MISSISSIPPI
	SUMMER PEAK DEMAND WITHOUT TRANSMISSION COSTS				
9	600	3201	2378	180	0
	WINTER PEAK DEMAND WITHOUT TRANSMISSION COSTS				
10	600	2269	2099	0	0
	SUMMER PEAK DEMAND WITH TRANSMISSION COSTS				
13	600	2520	2177	10	0
	WINTER PEAK DEMAND WITH TRANSMISSION COSTS				
14	600	1458	1899	0	0

losses were not a factor. It can therefore be concluded that if Louisiana's electric power system had the capability of receiving more power from ERCOT, it would do so.

To the north and east, Entergy Arkansas and Southern Companies (Mississippi Power Company) produce inexpensive power on both an average variable and fuel cost basis, and a significant amount of that power could be imported into Louisiana's system. It is interesting to note that bundled transmission interconnection prices do affect the amount of power each company imports. Bundled prices reduce power imports from Entergy Arkansas by 21% during summer peak demand and 36% during winter peak demand. They also reduce imports from Southern Companies by 8% during summer peak demand and 10% during winter peak demand.

Finally, to the northwest and northeast, Public Service Company of Oklahoma and Entergy Mississippi produce uneconomic power when referenced to Louisiana's production costs. Entergy Mississippi's power is never dispatched into Louisiana's system by LaDEUX, and only a very small amount of power from Public Service Company of Oklahoma is dispatched into SWEPCO's control area in experiment #9 (experimental factors: fuel production cost, summer peak demand, and unbundled transmission costs) and experiment #13 (experimental factors: fuel production cost, summer peak demand, and bundled transmission costs). Again, it is interesting to note that bundled transmission interconnection costs do affect the amount of power exported

by Public Service Company of Oklahoma and reduce it by as much as 95%.

6.4 Estimates of Stranded Generation Facility Costs

The two cost analysis methods presented in Chapter 4 can be applied to all generation facilities within LaDEUX, but not all facilities qualify for stranded cost recovery. For instance, municipally-owned generation facilities are not subjected to regulatory review and are therefore not eligible to recover any stranded generation facility costs. The same is true for qualifying facilities. It is the ambition of this research to estimate recoverable stranded generation facility costs. Hence, these are costs that are from facilities regulated by the Louisiana Public Service Commission.

Marginal production costs for economic dispatch of Louisiana's generation facilities are not published. Thus, it was decided early on that this research methodology would be designed to estimate a range for stranded generation facility costs by means of production cost boundaries known to include marginal production costs. Marginal costs are composed of fuel costs and other operational costs along with maintenance costs (O&M) and the variable portion of administrative and general (A&G) costs. They are known to exist between the boundaries of average variable production costs and fuel production costs, though probably closer to fuel costs. The reader may wish to reference Figure 3.4 for the research methodology's original experimental design.

The economic dispatching of generation facilities and market clearing prices from the experiments designed in Chapter 3 were required before the estimation of stranded generation facility costs could begin. Once known, only the information concerning non-dispatched facilities was used to determine the range for stranded generation facility costs by the Cost-of-Plant method. These are estimates for stranded costs in their strictest form. Other estimates of stranded generation facility costs were found by the Embedded Cost method. This method extends the approach of the Cost-of-Plant method to include costs of uneconomically dispatched facilities. It does so by comparing a dispatched facility's embedded capital cost with an experimental market clearing price.

The following subsections provide stranded generation facility cost boundary estimates by seasonal peak demand. The Embedded Cost method's capital cost component is computed assuming a 12% regulated nominal rate-of-return on capital for unbundled generation facilities. A 6% present worth factor is also assumed. Other present worth factors could be assumed depending upon the assumptions used for inflation and tax rates. Costs incurred by each investor-owned electric utility estimated by the Cost-of-Plant method can be found in Appendix F. The same information can be found in Appendix G by means of the Embedded Cost method.

6.4.1 Stranded Cost Results for Summer Peak Demand

Table 6.9 provides summer peak demand economic dispatch results from LaDEUX for all odd numbered experiments. The table displays market clearing prices and market clearing facilities by average variable cost and fuel cost dispatching. Market clearing prices for experiments #9, #11, #13, and #15 from fuel cost dispatching were relatively stable, between $32 and $34, with market clearing facilities located in several different geographic locations around the state. The market clearing prices and facilities determined by average variable cost dispatching were not as stable and geographically diverse. For experiments #1, #3, and #5, all market clearing facilities were located in the New Orleans area with somewhat stable market clearing prices, but experiment #7's market clearing price was remarkably high. Experiment #7's result indicates the importance of transmission interconnection constraints and costs on a closed system when attempting to wheel power to customers in northern Louisiana.

Table 6.10 provides estimates for stranded generation facility costs during summer peak demand using both cost analysis methods. Estimates by the Cost-of-Plant method are greatly influenced by experimental industry factors under summer peak demand conditions. As a general observation, one should note how power imports greatly affect the Cost-of-Plant estimates. An open system for power imports more

TABLE 6.9
SUMMER PEAK DEMAND
MARKET CLEARING PRICES (MCP) AND
MARKET CLEARING FACILITIES (MCF) FOR
AVERAGE VARIABLE COST (AVC) AND FUEL COST (FC) DISPATCHING

EXP #	MCP FOR AVC DISPATCH	MCF FOR AVC DISPATCH	EXP #	MCP FOR FC DISPATCH	MCF FOR FC DISPATCH
AN OPEN SYSTEM WITHOUT TRANSMISSION COSTS					
1	$66.8/MWh	Little Gypsy	**9**	$32.0/MWh	Michoud
A CLOSED SYSTEM WITHOUT TRANSMISSION COSTS					
3	69.4	Michoud	**11**	33.0	Sterlington
AN OPEN SYSTEM WITH TRANSMISSION COSTS					
5	66.8	Little Gypsy	**13**	32.0	Little Gypsy and Michoud
A CLOSED SYSTEM WITH TRANSMISSION COSTS					
7	79.0	Sterlington	**15**	34.0	Hunter

TABLE 6.10
RANGE ESTIMATES FOR STRANDED GENERATION FACILITY COSTS
FROM THE 8 SUMMER PEAK EXPERIMENTS USED TO CAPTURE
MARGINAL PRODUCTION COSTS

EXP #	COST ANALYSIS METHOD	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
AN OPEN SYSTEM WITHOUT TRANSMISSION COSTS			
1,9	Cost-of-Plant	$ 812,666,241	$ 876,736,445
	Embedded Cost	$2,325,480,335	$5,468,048,773
A CLOSED SYSTEM WITHOUT TRANSMISSION COSTS			
3,11	Cost-of-Plant	$ 385,714,093	$ 374,815,226
	Embedded Cost	$1,908,322,794	$5,397,932,752
AN OPEN SYSTEM WITH TRANSMISSION COSTS			
5,13	Cost-of-Plant	$ 780,482,459	$ 809,002,276
	Embedded Cost	$2,320,265,434	$5,471,627,942
A CLOSED SYSTEM WITH TRANSMISSION COSTS			
7,15	Cost-of-Plant	$ 379,181,222	$ 362,629,999
	Embedded Cost	$ 984,268,058	$5,336,844,436

than doubles the estimated amount of stranded generation facility costs. In contrast, estimates obtained by the Embedded Cost method are fairly stable since they are based on each experiment's market clearing price.

The only result in Table 6.10 that is out of the ordinary is the Embedded Cost estimate for average variable cost dispatching obtained for experiment #7. It is less than half of other similar summer peak demand average variable cost dispatching results. This result is explained by its experimental market clearing price of $79.0/MWh. It is much higher than other summer peak demand, average variable cost, experimental market clearing prices found in Table 6.9. Its occurrence allows for all generation facilities with embedded costs under this abnormally high market clearing price to operate profitably.

6.4.2 Stranded Cost Results for Winter Peak Demand

Table 6.11 provides winter peak demand economic dispatch results from LaDEUX for all even numbered experiments. The table displays market clearing prices and market clearing facilities by average variable and fuel cost dispatching. Market clearing prices for experiments #10, #12, #14, and #16 from fuel cost dispatching were relatively stable, between $31 and $32, with all market clearing facilities located in the New Orleans area. In a similar fashion, Entergy's Nine Mile Point facility was the market clearing facility and provided the market clearing

price for experiments #2, #4, #6, and #8 using average variable cost dispatching.

The stability of these results is not unexpected since winter peak demand is much more predictable and easier to manage in the southern United States than summer peak demand. This is because most electric utility system planning is based on summer peak demand. Winter peak demand is simply regulated by transitional generation facilities designed to manage the summer peak demand cycle.

Table 6.12 provides estimates for stranded generation facility costs during winter peak demand using both cost analysis methods. Estimates by the Cost-of-Plant method are, once again, influenced by the utilization of specific experimental industry factors. As a general observation, one must again note how power imports affect the Cost-of-Plant estimates. Stranded generation facility cost estimates for an open system are approximately $200 to $300 million less than the estimates for a closed system. In contrast, estimates obtained by the Embedded Cost method are once again stable since they are based on each experiment's market clearing price.

6.4.3 A Comparison of Stranded Cost Analysis Methods

When comparing the Cost-of-Plant figures of Tables 6.10 and 6.12, one can collectively conclude that winter peak demand estimates for stranded generation facility costs are significantly higher, approximately $350 to $550 million higher regardless of any other experimental

TABLE 6.11
WINTER PEAK DEMAND
MARKET CLEARING PRICES (MCP) AND
MARKET CLEARING FACILITIES (MCF) FOR
AVERAGE VARIABLE COST (AVC) AND FUEL COST (FC) DISPATCHING

EXP #	MCP FOR AVC DISPATCH	MCF FOR AVC DISPATCH	EXP #	MCP FOR FC DISPATCH	MCF FOR FC DISPATCH
	AN OPEN SYSTEM WITHOUT TRANSMISSION COSTS				
2	$64.2/MWh	9 Mile Point	**10**	$31.0/MWh	9 Mile Point
	A CLOSED SYSTEM WITHOUT TRANSMISSION COSTS				
4	64.2	9 Mile Point	**12**	32.0	Michoud
	AN OPEN SYSTEM WITH TRANSMISSION COSTS				
6	64.2	9 Mile Point	**14**	32.0	Michoud
	A CLOSED SYSTEM WITH TRANSMISSION COSTS				
8	64.2	9 Mile Point	**16**	32.0	Michoud

TABLE 6.12
RANGE ESTIMATES FOR STRANDED GENERATION FACILITY COSTS
FROM THE 8 WINTER PEAK EXPERIMENTS USED TO CAPTURE
MARGINAL PRODUCTION COSTS

EXP #	COST ANALYSIS METHOD	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
	AN OPEN SYSTEM WITHOUT TRANSMISSION COSTS		
2,10	Cost-of-Plant	$1,186,737,595	$1,311,133,168
	Embedded Cost	$2,569,594,430	$5,536,825,022
	A CLOSED SYSTEM WITHOUT TRANSMISSION COSTS		
4,12	Cost-of-Plant	$ 933,605,105	$ 912,716,646
	Embedded Cost	$2,509,275,930	$5,475,240,712
	AN OPEN SYSTEM WITH TRANSMISSION COSTS		
6,14	Cost-of-Plant	$1,176,462,080	$1,231,220,541
	Embedded Cost	$2,576,043,068	$5,483,069,650
	A CLOSED SYSTEM WITH TRANSMISSION COSTS		
8,16	Cost-of-Plant	$ 925,734,685	$ 908,219,301
	Embedded Cost	$2,507,397,127	$5,475,608,051

factors. Figure 6.1 illustrates these findings. Since costs are strictly being applied to facilities that are not dispatched, these results are not unexpected. In contrast, when one compares the Embedded Cost results of Tables 6.10 and 6.12, different conclusions are drawn depending on which production cost dispatching factor is used. Stranded generation facility costs found by dispatching with an average variable cost priority are much different than stranded costs obtained by fuel cost dispatching. When using average variable costs dispatching, uneconomically dispatched generation facilities reveal a reasonable increase (approximately doubles on average) over estimates obtained using the Cost-of-Plant method. These estimates exhibit signs of costs differences based on seasonal demand, power imports, and transmission interconnection costs. In addition, when average variable cost dispatching is used, 10 of the 38 generation facilities operate profitably and are considered to be stranded benefits in all experiments performed (#1 through #8). Table 6.13 identifies these facilities. Market clearing prices between \$64.2/MWh and \$79.0/MWh for the experiments were high enough to support such profitable operation.

Much different stranded cost results were obtained when fuel cost dispatching was used. The results of all eight experiments (#9 through #16) are very similar. Estimates of stranded generation facility costs do not exhibit costs differences based on seasonal demand, power

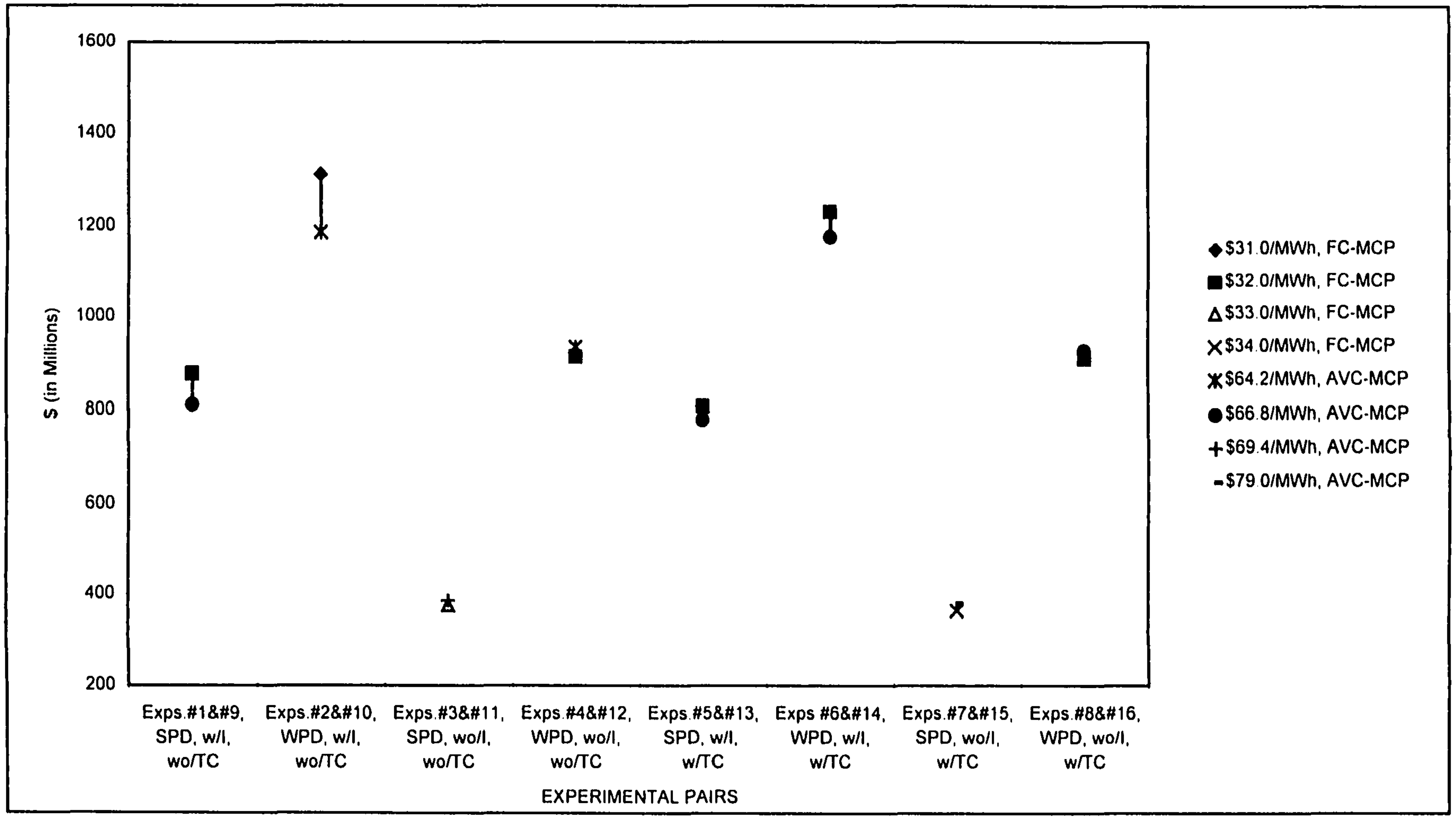


FIGURE 6.1
BOUNDARY ESTIMATES FOR STRANDED GENERATION FACILITY COSTS
USING THE COST-OF-PLANT METHOD

TABLE 6.13
GENERATION FACILITIES IDENTIFIED AS STRANDED BENEFITS UNDER AN AVERAGE VARIABLE COST DISPATCHING PRIORITY

PLANT NAME	QF/HOST	ST	FUEL TYPE	TOTAL EMBEDDED COST	MW CAPACITY
Rodemacher 2	CLECO	LA	Coal	$39.32/MWh	558.00
Pirkey 8	SWEPCO	TX	Lgnt	44.21	619.38
Welsh 6	SWEPCO	TX	Coal	48.97	1,674.00
Dolet Hills	CLECO	LA	Lgnt	55.15	650.37
Big Cajun 1	Cajun	LA	Gas	55.49	230.00
Lewis Creek	SWEPCO	TX	Gas	57.71	544.00
Teche	CLECO	LA	Gas	58.08	427.90
Wilkes 5	SWEPCO	TX	Gas	59.75	881.52
Sabine	Entergy	TX	Gas	60.60	2,051.00
Waterford 3	Entergy	LA	Nclr	63.68	1,200.00

imports, and transmission interconnection costs. Figure 6.2 illustrates this point. Fuel production cost dispatching provided market clearing prices low enough, between $31.0/MWh and $34.0/MWh, to expose the uneconomical operation of all investor-owned facilities which would require stranded cost recovery over time of all net book values.

6.5 Other Economic Dispatching Conclusions

The most important finding from the LaDEUX model is not peak-hour production cost, but the determination of a market clearing price and identification of the market clearing facility. It is the market clearing price which makes possible the estimation of stranded generation facility costs.

Analysis of the economic dispatch results provided another interesting observation concerning the determination of the market clearing facility. In 12 of the 16 experiments

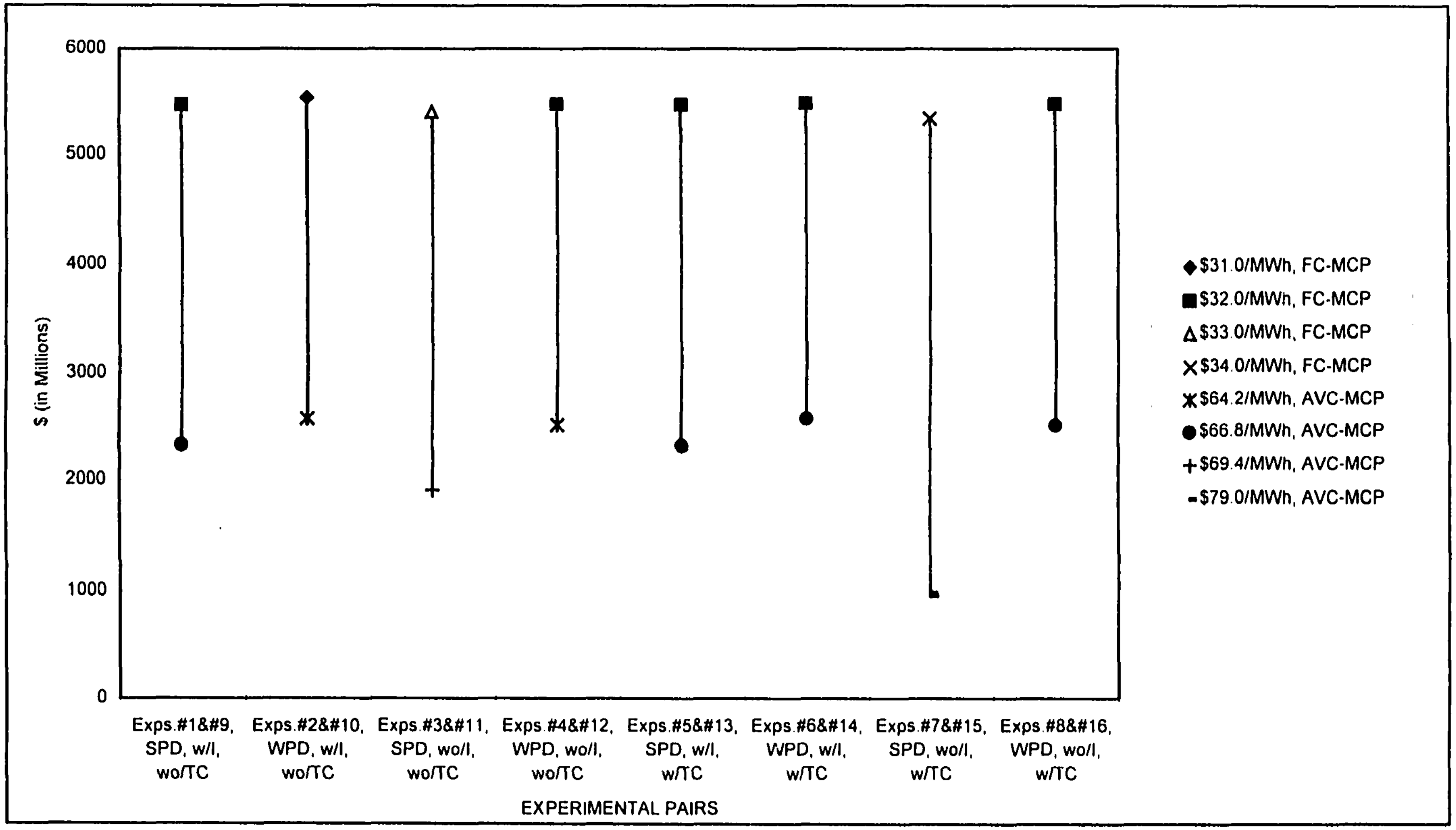


FIGURE 6.2
BOUNDARY ESTIMATES FOR STRANDED GENERATION FACILITY COSTS
USING THE EMBEDDED COST METHOD

performed, at least one uneconomically priced generation facility was dispatched in favor of a more economically priced facility. This confirms the existence of a discontinuous supply curve for Louisiana's generation system which was first mentioned in Section 6.2. The discontinuities were created by transmission interconnection constraints as well as costs. This discovery indicates that any wholesale or retail wheeling study of Louisiana's power production capabilities for stranded cost determination that does not take into account constraints associated with transmission interconnections would not adequately assess stranded and uneconomically operating generation facilities.

Figures 6.3, 6.4, 6.5, and 6.6 indicate the existence of the supply system discontinuities. In each graph, supply curves of like experiments are compared to a supply curve developed from pure economic dispatch (ECON. DISPATCH), which is dispatching without transmission interconnection constraints. These graphs indicate that transmission interconnections play a vital role in the determination of stranded and uneconomically dispatched generation facilities and their costs.

The discontinuities also established the existence of a load pocket. This is an area where demand is typically high and economically produced power is not able to penetrate it enough to force market clearing prices down. In 13 of the 16 experiments performed, the market clearing facility was located in the New Orleans area. Given

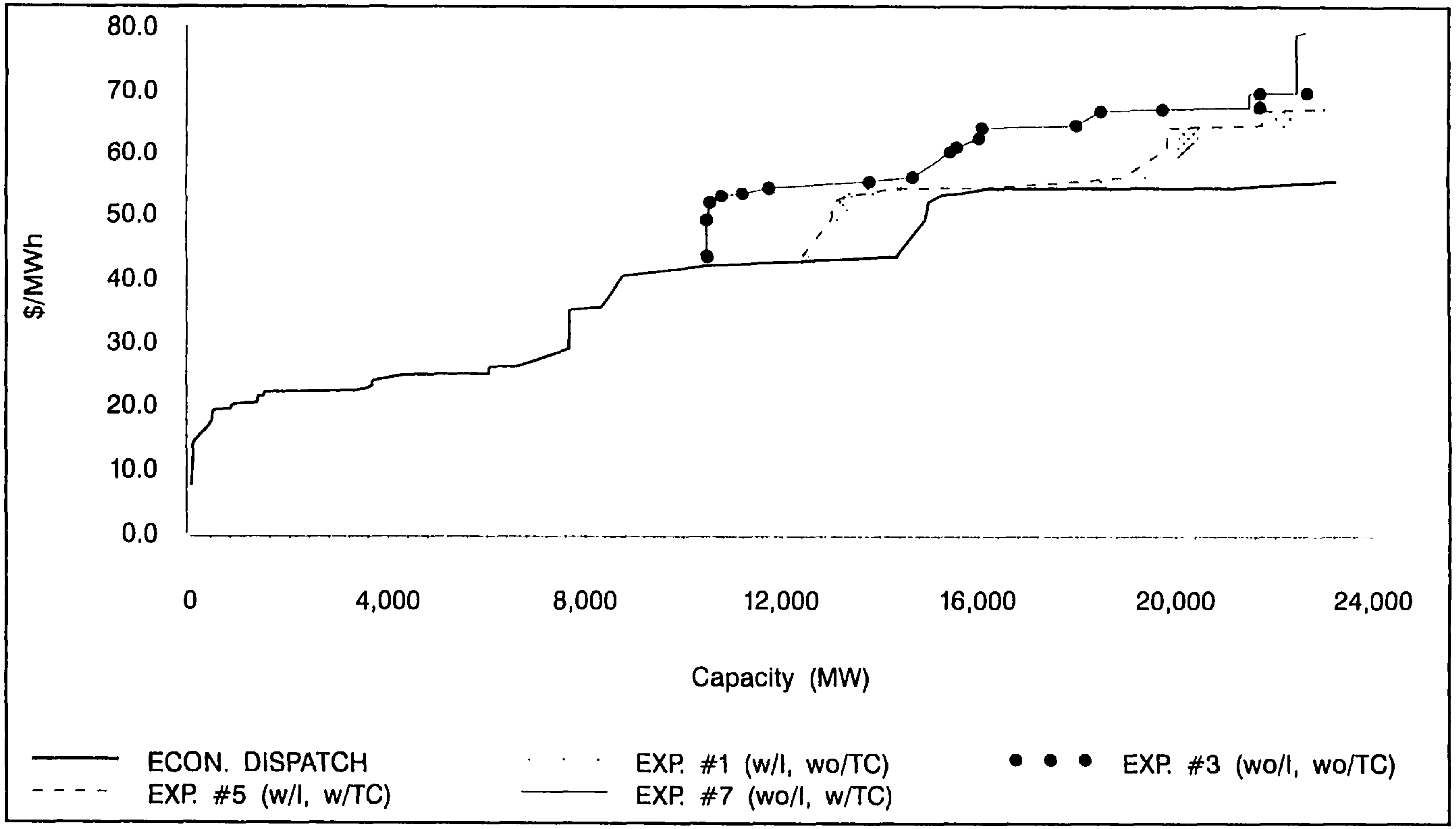


FIGURE 6.3
SUPPLY CURVES BASED ON
AVERAGE VARIABLE COST DISPATCHING
AND SUMMER PEAK DEMAND

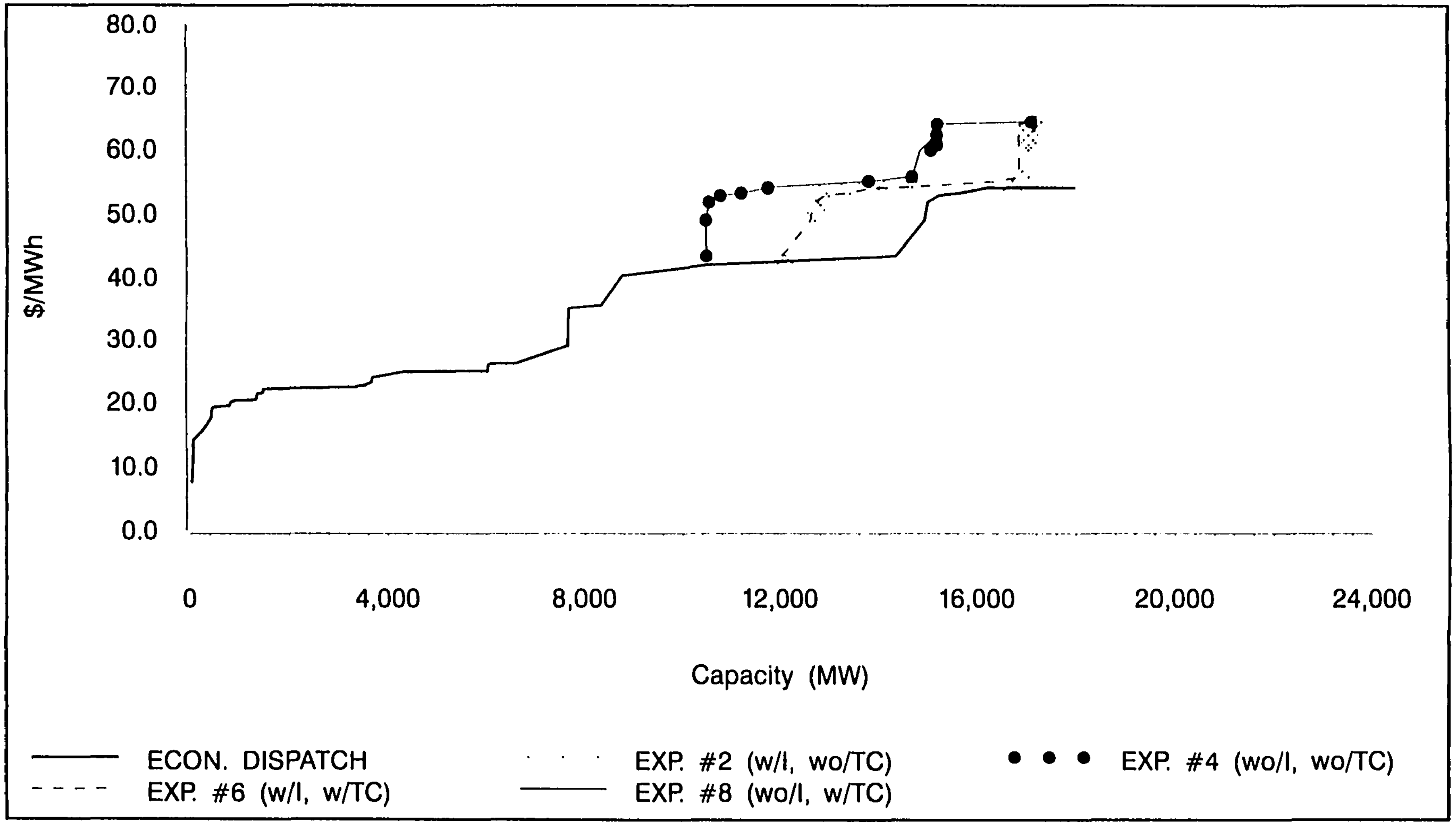


FIGURE 6.4

SUPPLY CURVES BASED ON
AVERAGE VARIABLE COST DISPATCHING
AND WINTER PEAK DEMAND

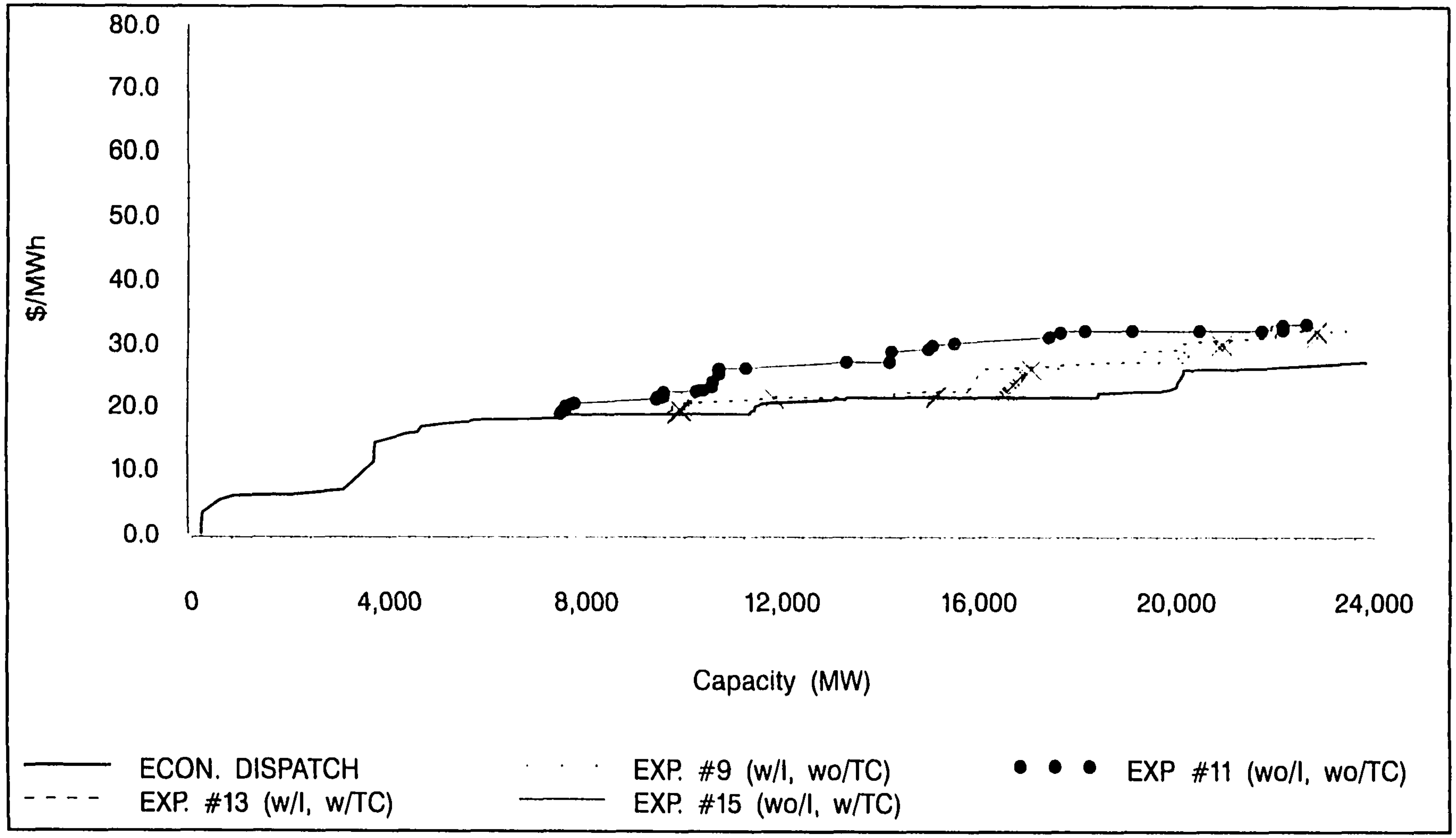


FIGURE 6.5
SUPPLY CURVES BASED ON
FUEL COST DISPATCHING
AND SUMMER PEAK DEMAND

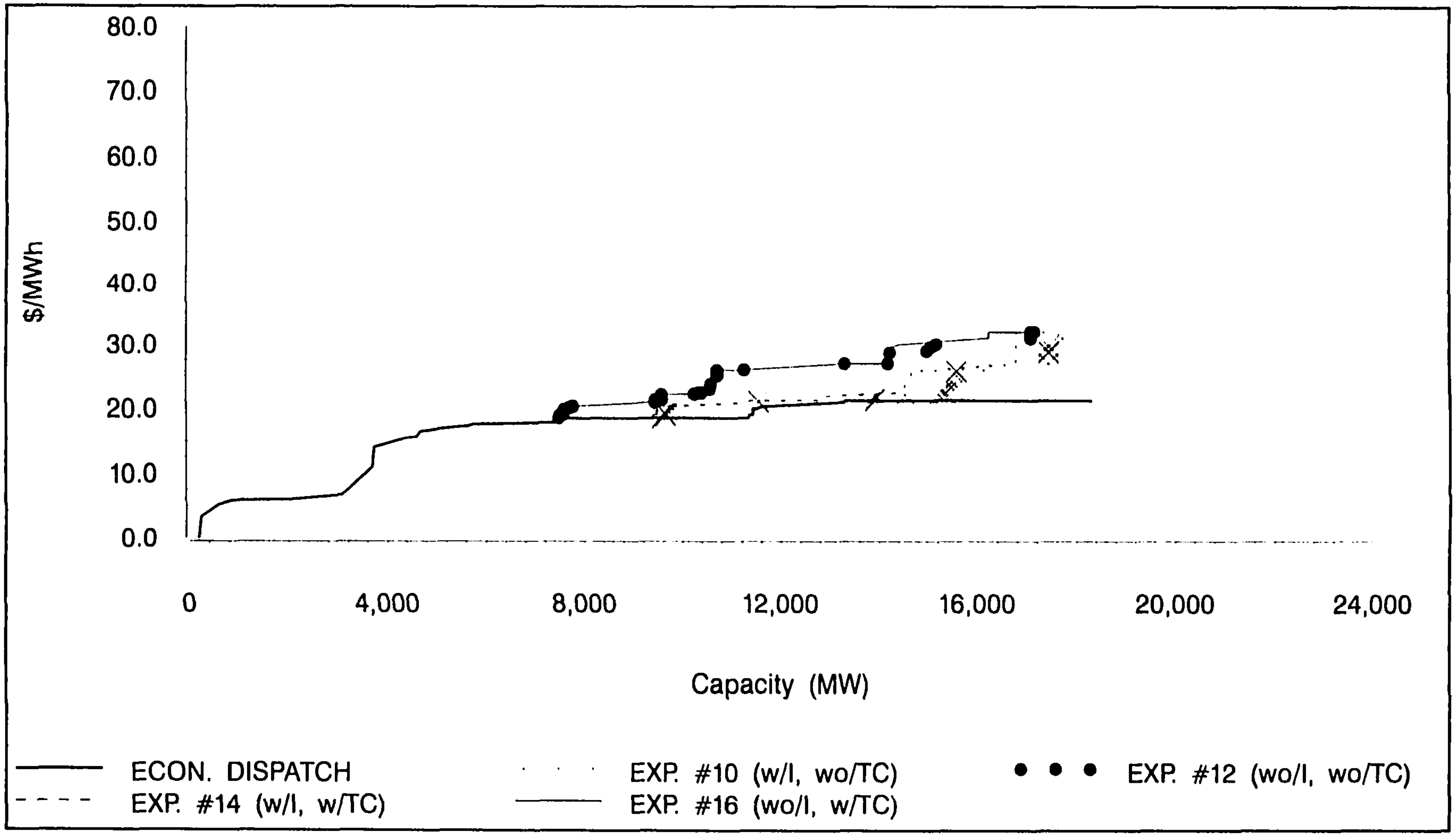


FIGURE 6.6
SUPPLY CURVES BASED ON
FUEL COST DISPATCHING
AND WINTER PEAK DEMAND

appropriate modeling parameters and existing transmission interconnection infrastructure, the 13 experiments suggested that wheeling power into the southeastern portion of Louisiana is difficult. This would be especially true if other inefficient methods of restructuring, such as Bilateral Contracts, are implemented.

In addition to the load pocket discovery, it was noted that Entergy Louisiana's Waterford 3 facility operates as a stranded benefit in 8 of the 16 experiments performed. These experiments all involve economic dispatch based on the use of average variable production costs, one of the boundaries for capturing marginal production costs. This was another interesting finding since most investor-owned utility companies claim their nuclear facilities are the largest portion of their stranded costs. In Louisiana's case, half of the experiments have shown that the New Orleans load pocket is keeping market clearing prices high enough to allow Waterford 3 to operate as a profitable facility. River Bend, of Entergy Gulf States, and Grand Gulf, of System Energy Resources, are not as fortunate. Experimental market clearing prices would have to increase substantially before they would cover the embedded capital costs of these two facilities and allow them to operate profitably.

One final result of this research confirmed the existence of stranded qualifying facilities. Dismukes and Kleit (1997) presented power market conditions in which qualifying facilities could be considered uneconomical to

operate, hence stranding the facility without the benefit of recovery.

Four qualifying facilities and one contracted facility supported the existence of this theorized market condition. Two Entergy Gulf States qualifying facilities, BASF and Agrielectric, were not dispatched by LaDEUX in 3 of 16 and 8 of 16 experiments respectively, whereas two of SWEPCO's qualifying facilities, Dean Lumber and Snider Industries, were each not dispatched by LaDEUX in 2 of 16 experiments. In addition, the Sidney A. Murray, Jr., hydroelectric facility contracted by Entergy Louisiana was not dispatched by LaDEUX in 4 of 16 experiments. The combination of transmission system constraints and above average power production costs was the reason for non-dispatch in all cases.

6.6 The California Power Exchange

Some have questioned whether the production figures of average variable and fuel costs used to estimate true marginal production costs are realistic. The best method of clarification would be a comparison of Louisiana's production cost figures to actual market clearing prices obtained from an existing power exchange. Fortunately, there is such an exchange in existence. Since January 1, 1998, a new competitive market for electric power has been in operation in California.

The present California Power Market consists primarily of utility-owned generation, transmission, and distribution

used to meet each utility's demand by way of a complicated market comprised of both Poolco and Bilateral Contract systems. There are three major control areas operated by three investor-owned utilities. Each utility is responsible for matching demand and resources within its control area to maintain technical constraints and match scheduled and actual flows at the interconnection points.

The power market has only been in existence for the past six months and has not yet reached peak demand. Therefore, any data gathered during its first year of operation should be considered experimental (warm-up data) and not used for designing other power exchange systems. Table 6.14 indicates peak market clearing prices for each of the four weeks of June 1998 for comparison purposes.

TABLE 6.14
PEAK DEMAND VOLUME AND MARKET CLEARING PRICE DATA FOR THE CALIFORNIA POWER MARKET DURING JUNE 1998

WEEK OF	PEAK DEMAND VOLUME (MWHS)	PEAK MARKET CLEARING PRICE
June 1- 7, 1998	24,340.0	$26.40/MWh
June 8-14, 1998	23,814.7	22.07
June 15-21, 1998	27,456.1	38.02
June 22-30, 1998	28,499.4	37.01

One must realize that these are peak market clearing prices presented in Table 6.14, not market clearing costs. They may be inflated to reflect strategies used to subsidize low demand periods during each day. For instance, early morning

bids from generation facilities have been known to approach $0.00/MWh. Power is not free. There is always some production cost, but this strategy is used to keep generation facilities connected to the power grid and spinning. It is uneconomic for a generation facility to be unconnected from the grid and spinning. It is also uneconomic for a facility to be unconnected and not spinning since start-up can take as long as 10 to 24 hours, on average, depending on the type of facility. Therefore, peak day (typically 2-6 p.m.) pricing is known to include margins to cover the early morning costs associated with this production strategy.

For comparison purposes, Louisiana's fuel production costs figures used to estimate true marginal production costs are more closely related to the market clearing prices of California's Power Exchange. Unfortunately, an accurate comparison is not possible at this time since summer peak demand data are not available. However, if the early trend of market clearing prices in the $35/MWh to $45/MWh range continues, it could be an indication that Louisiana is certain to have stranded generation facility costs totaling 4 to 5 billion dollars.

6.7 Experimentation Results Summary

The results of this two stage methodology have provided a significant contribution to restructuring Louisiana's electric utility system. First, two levels of peak demand, power imports, and transmission interconnection

costs were used to test response sensitivities to the LaDEUX model where market clearing facilities and market clearing prices were determined. This information was then used in the second stage of the methodology to implement the Cost-of-Plant and Embedded Cost methods of stranded generation facility cost analysis. Each method provided a range for estimating stranded generation facility costs.

The chapter presented several interesting results concerning the classification of generation facilities, identification of stranded facilities, formation of a load pocket, and boundary estimates for stranded and uneconomically dispatched generation facility costs. More importantly, it has opened the door for future research incorporating other economic and decision science topics to add more detail and further refine these estimates.

CHAPTER 7

CONCLUSIONS AND FUTURE RESEARCH

7.1 Introduction

With oncoming competition brought forth by The Energy Policy Act of 1992, many regulatory bodies and electric utility companies must determine the economic condition of their system's generation mix. This research focused on a "Bottom-Up" method for estimating such economic conditions. It predicted stranded generation facilities for Louisiana using a Poolco restructuring method to estimate investor-owned utility stranded generation facility costs.

The "Bottom-Up" approach began with the construction of a nonlinear programming model, LaDEUX, to provide an economic dispatch of deregulated generation facilities to meet Louisiana's summer and winter peak needs. Sensitivity analysis for LaDEUX was conducted by designing several experiments to simulate industry conditions. Each experiment provided contrasting generation facility economic dispatch. To conclude the "Bottom-Up" process, two methods of cost analysis were employed to estimate investor-owned utility stranded generation facility costs.

Results based on experimentation of LaDEUX and subsequent costs analysis are summarized in Section 7.2. Economic and technical limitations to the results are presented in Section 7.3. Topics for future research are

discussed in Sections 7.4 and 7.5, and finally, general conclusions are drawn in Section 7.6.

7.2 Research Results

Chapter 6 presented two stage results which first determined the economic dispatch of Louisiana's electric utility system from the LaDEUX model and then provided estimates of stranded generation facility cost. Some interesting conclusions concerning the restructured operation of Louisiana's electric utility system were drawn from the research methodology.

In the first stage of the methodology, the following sets of factors were used to create sixteen experiments, or eight experimental boundary cases, for capturing marginal production costs.

(1) Fuel vs. Average Variable Production Costs,
(2) Summer vs. Winter Peak Demands,
(3) Opened vs. Closed Power Import Policies, and
(4) Bundled vs. Unbundled Transmission Interconnection Costs.

Complete economic dispatch results from all LaDEUX experiments can be found in Appendix F.

While reviewing these results, it was noted that Louisiana's generation facilities could be categorized into three distinct classes. The classes are:

(1) must-run facilities,
(2) transitional facilities, and
(3) stranded facilities.

Generation facilities within each classification provided particular contributions toward stranded generation facility cost estimates.

The economic dispatch experiments were designed to determine a coincident peak hour production cost for Louisiana's electric utility system, but also indicated the system's market clearing price and market clearing facility. Other interesting economic dispatch discoveries included the identification of a New Orleans area load pocket, the recognition of discontinuous generation production supply curves, and the justification of previous research theorizing the potential for stranded qualifying facilities.

Each of the discoveries is significant, but the detection of discontinuous supply curves for Louisiana's generation system is a major finding of this research. It proves that any study of the state's generation facilities that does not take into account transmission interconnection constraints is incapable of accurately evaluating stranded generation facility costs.

In the second stage of the methodology, stranded generation facility costs were calculated using LaDEUX's economic dispatch results and supplied the following optimistic and pessimistic stranded costs estimates.

OPTIMISTIC
STRANDED GENERATION FACILITY COSTS: $ 984,268,058

This figure was obtained using the Embedded Cost method for stranded cost estimation and the following experimental dispatch factors:

(1) average variable production costs,
(2) coincident summer peak demand conditions,
(3) a closed power import policy, and
(4) bundled transmission interconnection costs.

PESSIMISTIC
STRANDED GENERATION FACILITY COSTS: $ 5,536,825,022

This figure was obtained using the Embedded Cost method for stranded cost estimation and the following experimental dispatch factors:

(1) fuel production costs,
(2) coincident winter peak demand conditions,
(3) an open power import policy, and
(4) unbundled transmission interconnection costs.

Economic dispatch results indicated that LaDEUX experiments which included power imported from neighboring electric utilities greatly affected the identification of Louisiana's stranded generation facilities and estimates for their costs. The estimates were higher for open system experiments compared to closed system experiments. These results were expected, but they indicated the additional amount of stranded costs incurred if Louisiana's electric utilities decided to strand their own high cost facilities and purchase inexpensive power on the open market. In addition, results showed that stranded generation facility cost estimates climbed even higher when transmission interconnection costs were bundled with production costs. These results were also expected.

There is some concern about complete stranded generation facility cost recovery. The concern has to do with the fact that once these stranded or uneconomically operating facilities are completely depreciated, owners will have the ability to manipulate market clearing prices and control their customer base. It is hoped that future

litigation or legislation will take this looming situation into consideration before rulings are made or policy is developed.

7.3 Research Limitations

In contrast to the interesting findings of this research, there are a few academic and practical limitations which should be mentioned. For instance, the Murray Hydro facility is always dispatched first by LaDEUX using the fuel production cost priority rule. This result is expected since the facility incurs no fuel costs. But, there is a problem with dispatching this facility to meet summer peak demand. The facility has the ability for peak production in the spring when northern snow melts and seasonal showers increase water levels in the Mississippi River. Unfortunately, peak demand does not occur in the spring. It occurs in late summer. Even though this is a low head, high volume facility, river conditions are generally low enough to constrain capacity. Consequently, another facility is required to provide the unmet capacity.

In addition, some readers may argue that there are technical limitations associated with the LaDEUX model. They may indicate that certain significant electrical components inherent to electrical networks are not completely modeled. This may be true, but because of the level of aggregation required for modeling control area generation facilities and transmission interconnections, a trade-off of detailed network load flow modeling must be made for economic

analysis. One must keep in mind that economic analysis is difficult to perform using detailed electric utility load flow software since costs are not part of the software's parameters.

Another controversial modeling subject to consider is the boundary issue associated with wheeling excess capacity. This shortcoming of assessing the ability of neighboring systems to wheel their excess power into the state can present uncertainties with identifying stranded generation facilities. The LaDEUX model is designed to saturate a power pool with as much power as transmission interconnections and model-driven market clearing prices will allow.

This modeling limitation may be valid since there is currently no restructuring precedent for meeting native demand first. If Louisiana's power market is priced higher than those of neighboring states, then generation facilities in those states may respond to market conditions by selling outside their native system for higher profits. The boundary issue has no definite solution but has the ability to increase stranded generation facility costs by stranding native facilities.

One final limitation concerns the static nature with which stranded generation facility costs are estimated. Price elasticities and efficiency gains are two topics that must be addressed since future market prices are expected to decline. The anticipated decline in prices coupled with an increase in demand will likely decrease estimates of

stranded generation facility costs. Further discussions concerning these two topics can be found in Sections 7.5.1 and 7.5.2.

7.4 Future Research for the LaDEUX Model

While developing the LaDEUX model, a number of additional research topics were identified. Each adds different qualities for economic dispatch. The topics include transmission interconnection pricing mechanisms, economic dispatch under environmental constraints, and simulation modeling. Each is described in separate sections below.

7.4.1 Transmission Interconnection Pricing Mechanisms

An electric utility company's transmission system is the "bridge" between market-driven generation facilities and regulated distribution facilities. It is the most important function when it comes to evaluating different restructuring methods. Wholesale, as well as retail, wheeling is not possible without sufficient capacity and advantageous pricing mechanisms.

Theories on pricing mechanisms for electric utility transmission system service fall into three distinct categories:

(1) postage stamp,
(2) distance-sensitive, and
(3) direction- and load-sensitive.

No matter which mechanism is implemented, transmission system owners must be assured of a return on their investment subject to FERC regulation.

In LaDEUX, only transmission system interconnections between competing control areas are modeled to determine the economic dispatch of generation facilities. The theories for determining rates for these interconnections are the same as the theories for determining rates for an entire transmission system. Brief descriptions of each theory are presented in the following paragraphs.

Postage stamp transmission rates are independent of distance and direction, and is the pricing mechanism of choice for this research. It is a simple and straight-forward pricing mechanism to implement since the same charge is applied whether transmission distance is long or short.

Distance-sensitive rates are based on the electrical distance between a generation facility source and electric load or, in other words, the distance over the primary electrical path. A common way to measure this is in MW-miles, which is the product of the capacity and distance involved.

This type of pricing mechanism sends "signals" to the market, whether intended or not. For example, distance-sensitive prices indicate where potential new generation facilities should be located. In addition, it discourages competition from more distant generation facilities. Therefore, if a high degree of distance sensitivity were built into transmission rates, one could draw a circle

around the load beyond which all generation facilities would be uncompetitive due to excessive transmission fees.

Direction- and *load-sensitive* rates attempt to price transmission usage on the basis of the scarcity of the resource at the time of use. Similar to the distance-sensitive pricing mechanism, this one also sends a "signal" to the market. Load-sensitive pricing indicates locations for new generation facilities in places where there is ample preexisting transmission capacity or where the prevailing direction of power flow on the system is opposite the intended flow pattern.

The addition of such distance-sensitive and direction- or load-sensitive pricing mechanisms would be expected to change solutions obtained from the LaDEUX model and in turn require an adjustment to estimates for stranded generation facility costs. The inclusion of such pricing mechanisms can provide an interesting new approach for determining stranded facilities and their costs.

7.4.2 Economic Dispatch with Environmental Constraints

Recent seminars on electric utility deregulation have presented environmental concerns associated with restructuring the industry. Adapting this research subject into the LaDEUX model to incorporate a set of constraints to simulate economic environmental dispatch should be straightforward. It is currently unclear how environmental concerns will affect economic dispatch and stranded generation facility costs for Louisiana, but this modeling

enhancement may help provide answers to environmental concerns.

7.4.3 Simulation Modeling of the Poolco System

There is also a dynamic nature to the problem of identifying stranded generation facilities and their costs since markets evolve in complex and unpredictable ways. In its current form, LaDEUX statically estimates stranded facilities at two moments in time, summer peak and winter peak. From these estimates, typical power engineering relationships are used for estimating annual energy sales to determine stranded costs for generation facilities. The reformulation of LaDEUX using dynamic simulation modeling techniques may improve the estimates of this research. This future research would be expected to take at least a year to implement. In addition, it is unclear at the present time if such an improvement in results would be worth the effort.

7.5 Future Research for the Embedded Cost Method

Determining true stranded generation facility costs requires the estimation of uncertain future market prices. The major reason for such uncertainty rests with not knowing the industry's future structure because it is being debated now. Therefore, three topics of future research for estimating stranded generation facility costs using the Embedded Cost method concern price elasticities, efficiency gains, and net stranded costs. Each is described in a separate section below.

7.5.1 Price Elasticities

Price elasticities can be used to further enhance estimates for stranded generation facility costs. Changes in summer and winter peak demand are expected as facility production costs change. As costs drop[1] and quantity demand rises, previously identified stranded generation facilities may become unstranded and reduce total stranded generation facility costs. Since this is simply an economic improvement of original cost data, there is no limit to the different levels of price elasticities that can be studied. The addition of price elasticities also creates the ability to study the dynamics of transmission interconnections. For instance, as production costs drop and seasonal peak demand rises, transmission interconnection capacity margins may decrease to a point where certain control areas become isolated and totally dependent on local production creating a new monopolistic market instead of an open market for electric power. If this situation could occur, significant rents would accrue to the owners of must-run generation facilities.

7.5.2 Efficiency Gains

Efficiency gains have not been included in the cost analysis process for a number of different reasons. First, the data used were taken from FERC Form 1 information for existing investor-owned utilities. All of these utilities were under traditional rate-of-return regulation at the time of publication, and, as noted earlier in this

research, this regulatory regime has been criticized as not providing utilities with adequate cost savings incentives. When analyzing utility expense activities, there has been no incentive to produce at a cost-minimizing level. Since traditional regulation sets a "reasonable" rate-of-return as its benchmark, any utility cost-minimizing activities are immediately passed on to ratepayers and not utility shareholders. Also, when analyzing utility capital activities, Averch and Johnson (1962) noted that rate-of-return regulation gave utilities incentives to over-capitalize and not produce efficiently.

A significant motivating factor in the policy debate of moving forward with restructuring rests with encouraging competition to stimulate cost efficiencies which do not exist under current rate-of-return regulation. Therefore, efficiency gain modifications to the Embedded Cost method for estimating stranded generation facility costs are needed and provide another interesting topic for continued research.

7.5.3 Net Stranded Costs

In this research, gross stranded costs were estimated for recovery. Net stranded costs differ from gross stranded costs because gross stranded costs ignore generation facilities that have market values greater than their book values. Baxter and Hirst (ORNL/CON-406, 1995) assume in their literature on estimating potential stranded commitments that a complete assessment of a utility's

competitive position should include both generation facilities that are above and below market value. Hence, estimates of net stranded generation facility costs would reflect the difference between uneconomical and economical facilities. They argue that a net stranded cost calculation is the appropriate measure of the potential losses to utility shareholders (or core customers) from wholesale or retail wheeling. Therefore, a natural progression of this research would include estimates for net stranded generation facility costs. It would provide an interesting and more realistic topic for continued work.

7.6 Dissertation Conclusions

This research has developed an innovative, two stage methodology for combining the technical and economic knowledge needed for the estimation of Louisiana's stranded generation facility costs. In the first stage, a nonlinear programming model was developed to provide the technical evaluation of generation facilities under economic dispatch. This part by itself is a significant contribution to restructuring Louisiana's electric utility system. It provides valuable information about the state's production capabilities to regulators, electric utilities, and power marketers. The second stage of the methodology contains two approaches for economic analysis to determine stranded costs associated with the assessment of non-dispatched and uneconomically dispatched generation facilities.

Electric utility deregulation was legislated without the vision of all restructuring implications for a new electric power market. This dissertation has successfully investigated the implications of stranded generation facilities and their costs. Thus, a foundation has been formed for future exploration into the many facets of this complex issue. Developing reasonable and equitable ways to mitigate and allocate stranded generation facility costs will be a crucial precondition to restructuring the electric utility industry both here in Louisiana and across the nation.

7.7 End Notes

[1] A drop in costs is defined as all production parties submitting lower bids into the Poolco.

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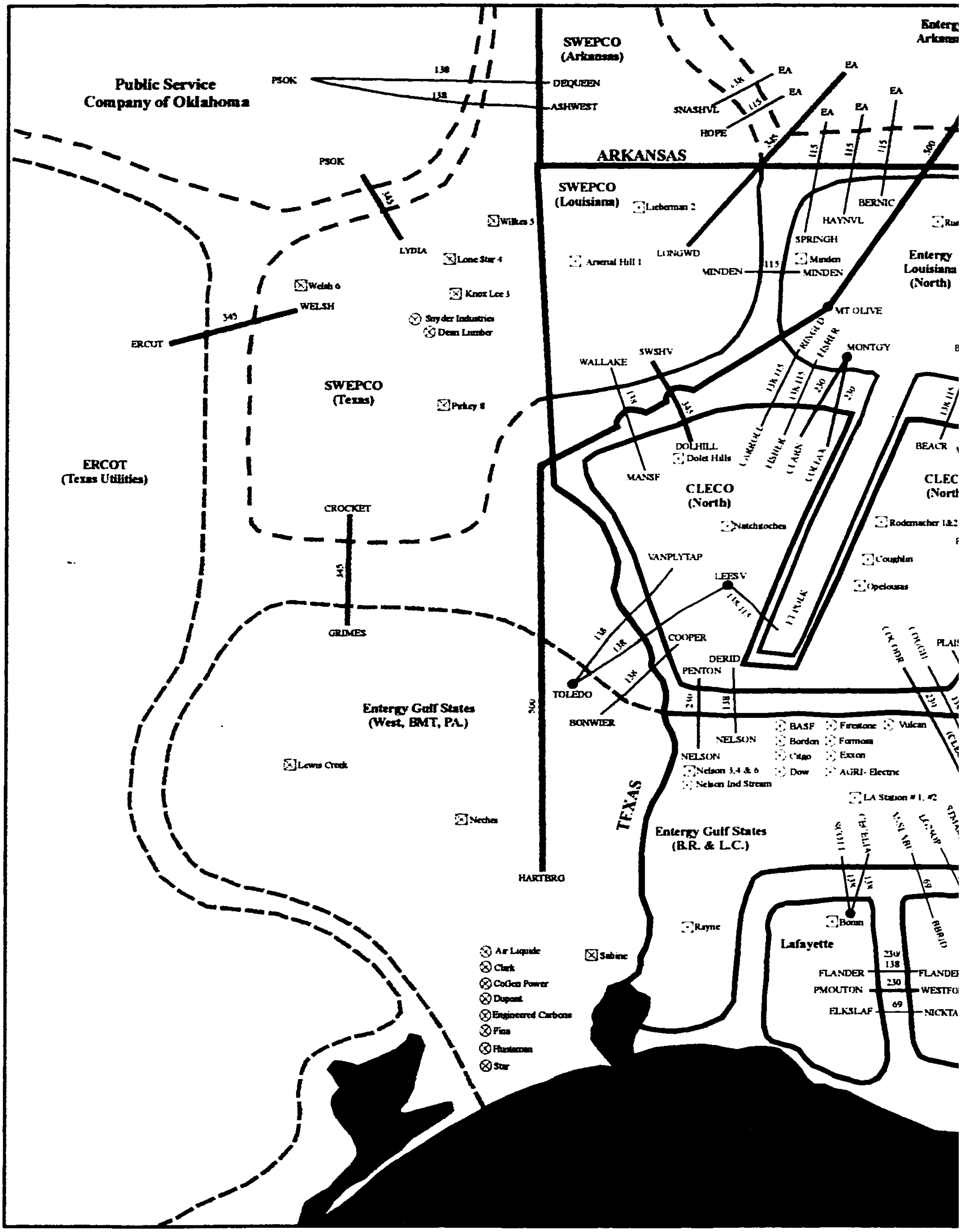
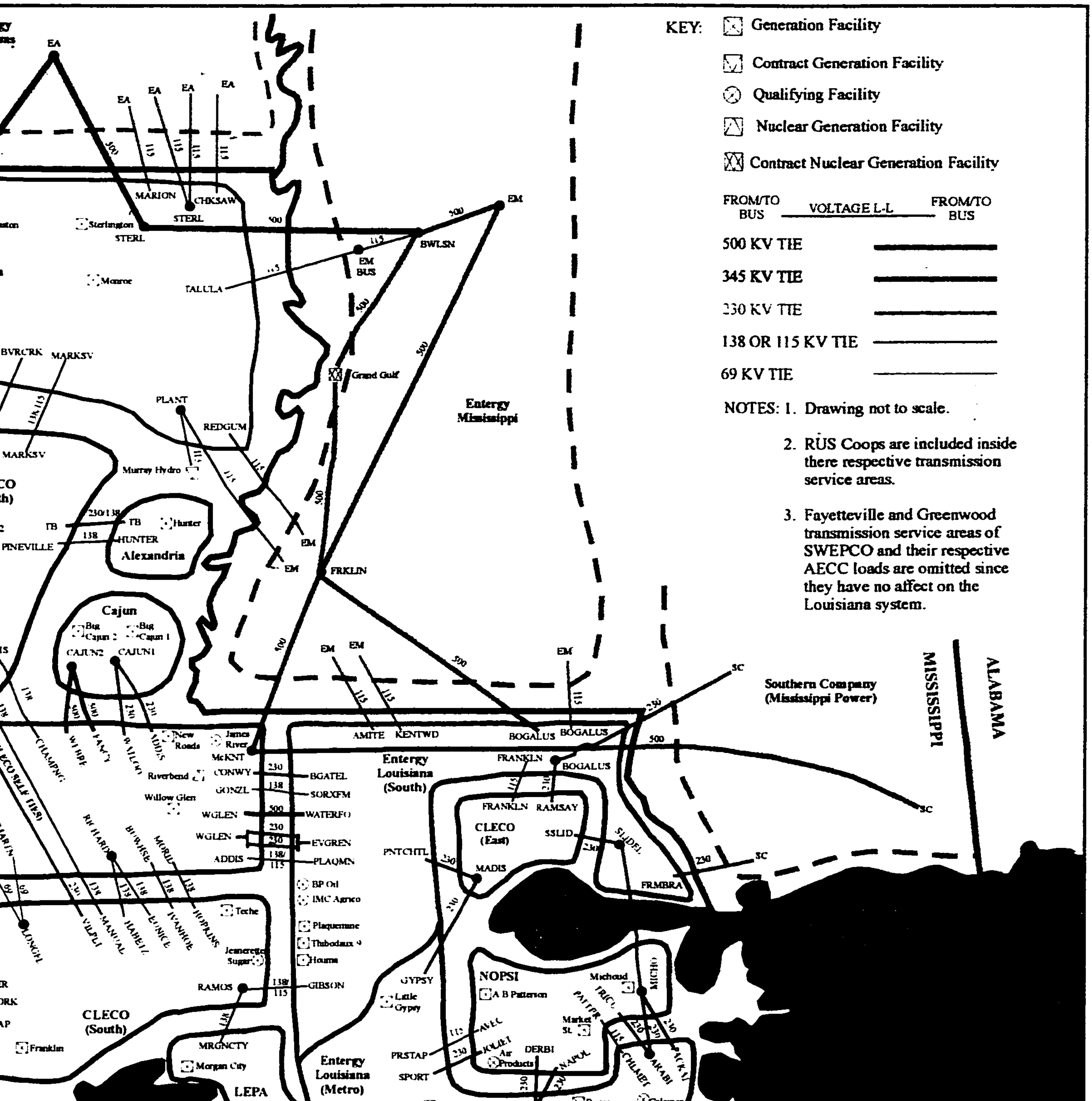
APPENDIX A

THE LOUISIANA SYSTEM MAP


Public Service
Company of Oklahoma
PSOK
DEQUEEN
ASHWEST
SWEPCO
(Arkansas)
SNASHVL
HOPE
ARKANSAS
SWEPCO
(Louisiana)
PSOK
LYDIA
WELSH
ERCUT
SWEPCO
(Texas)
ERCOT
(Texas Utilities)
CROCKET
GRIMES
Entergy Gulf States
(West, BMT, PA.)
HARTBRG
TEXAS
LONGWD
MINDEN
SPRINGH
HAYNVL
BERNIC
MT OLIVE
Entergy
Louisiana
(North)
MONTGY
WALLAKE
SWSHV
DOLHILL
MANSF
CLECO
(North)
VANPLYTAP
LEESV
COOPER
DERID
PENTON
TOLEDO
BONWIER
NELSON
Entergy Gulf States
(B.R. & L.C.)
Lafayette
FLANDER
PMOUTON
ELKSLAF
Welsh 6
Lone Star 4
Knox Lee 5
Snyder Industries
Dean Lumber
Pirkey 8
Wilkes 3
Lieberman 2
Arsenal Hill 1
Minden
Dolet Hills
Natchitoches
Rodemacher 1&2
Coughlin
Opelousas
Lewis Creek
Neches
Sabine
Rayne
BASF
Borden
Dow
Firestone
Formosa
Exxon
AGRI-Electric
Vulcan
Nelson 3,4 & 6
Nelson Ind Stream
LA Station #1, #2
Air Liquide
Clark
CoGen Power
Dupont
Engineered Carbons
Fina
Huntsman
Star


KEY:
Generation Facility
Contract Generation Facility
Qualifying Facility
Nuclear Generation Facility
Contract Nuclear Generation Facility
FROM/TO BUS
VOLTAGE L-L
FROM/TO BUS
500 KV TIE
345 KV TIE
230 KV TIE
138 OR 115 KV TIE
69 KV TIE
NOTES: 1. Drawing not to scale.
2. RUS Coops are included inside there respective transmission service areas.
3. Fayetteville and Greenwood transmission service areas of SWEPCO and their respective AECC loads are omitted since they have no affect on the Louisiana system.
Entergy Mississippi
Southern Company (Mississippi Power)
MISSISSIPPI
ALABAMA
Grand Gulf
Alexandria
Cajun
Entergy Louisiana (South)
CLECO (East)
NOPSI
Entergy Louisiana (Metro)
CLECO (South)
LEPA
MARION
CHKSAW
STERL
BWLSN
TALULA
PLANT
REDGUM
FRKLIN
AMITE
KENTWD
BOGALUS
FRANKLN
RAMSAY
SSLID
SLIDEL
FRMBRA
MADIS
PNTCHTL
GYPSY
PRSTAP
SPORT
DERBI
9 MILE
MRGNCTY
RAMOS
GIBSON
BGATEL
SORXFM
WATERFD
EVGREN
PLAQMN
CONWY
GONZL
WGLEN
ADDIS
McKNT
TB
HUNTER
PINEVILLE
MARKSV
BVRCRK
Murray Hydro
Riverbend
Willow Glen
Teche
Plaquemine
Thibodaux
Houma
Little Gypsy
A B Patterson
Michoud
Market St.
Air Products
Waterford 1&2
Waterford 3
9 Mile Point
Burns
Calciner
Morgan City
Franklin
Monroe
Sterlington

APPENDIX B

SYSTEM GENERATION DATA

APPENDIX B.1
GENERATION FACILITY PRODUCTION DATA SEPARATED BY CONTROL AREA AND RANKED BY AVERAGE VARIABLE COST

ENTERGY GULF STATES: CONTROL AREA = 1

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Fina Oil & Chem.**	Q.F./GSU	TX	GAS	37.00	0.01400	37.00
2	NISCO/RSNelson 1&2**	Q.F./GSU	LA	GAS	200.00	0.01570	237.00
3	E.I. Dupont**	Q.F./GSU	TX	GAS	85.00	0.01650	322.00
4	Exxon Chemical**	Q.F./GSU	LA	GAS	84.00	0.01760	406.00
5	Cogen Power	Q.F./GSU	TX	Waste Heat	5.00	0.01850	411.00
6	Formosa Plastics	Q.F./GSU	LA	GAS	46.00	0.01910	457.00
7	Engineered Carbons	Q.F./GSU	TX	Waste Heat	10.00	0.01980	467.00
8	Vulcan Chemical	Q.F./GSU	LA	GAS	108.00	0.02010	575.00
9	Huntsman Corp.	Q.F./GSU	TX	GAS	72.00	0.02030	647.00
10	Clark Refining	Q.F./GSU	TX	GAS	84.80	0.02130	731.80
11	Air Liquide	Q.F./GSU	TX	GAS	36.00	0.02140	767.80
12	Dow Chemical	Q.F./GSU	LA	GAS	670.00	0.02220	1437.80
13	James River Paper	Q.F./GSU	LA	Paper ByProd.	57.50	0.02240	1495.30
14	Borden Chemical	Q.F./GSU	LA	GAS	91.50	0.02240	1586.80
15	Star Enterprises	Q.F./GSU	TX	GAS	164.00	0.02290	1750.80
16	River Bend 1	GSU/CAJUN	LA	NUCLEAR	1022.30	0.02868	2773.10
17	BASF	Q.F./GSU	LA	GAS	36.60	0.02870	2809.70
18	Agrielectric	Q.F./GSU	LA	Rice Husks	12.50	0.03490	2822.20
19	Roy S. Nelson 6	GSU	LA	COAL	430.00	0.04020	3252.20
20	Lewis Creek	GSU	TX	GAS	544.00	0.05390	3796.20
21	Sabine	GSU	TX	GAS	2051.00	0.05500	5847.20
22	Roy S. Nelson 3&4	GSU	LA	GAS	755.00	0.05980	6602.20
23	Willow Glen	GSU	LA	GAS	2178.00	0.06710	8780.20
24	Rayne	Rayne	LA	GAS	2.50	0.32934	8782.70
25	New Roads	New Roads	LA	GAS	7.60	3.28619	8790.30
26	LA Station #1 Un.4A	GSU	LA		129.00	8.00000	8919.30
27	Louisiana Station #1	GSU	LA	GAS	148.00	8.00000	9067.30
28	Neches	GSU	TX		269.00	8.00000	9336.30
29	Louisiana Station #2	GSU	LA	GAS	175.00	8.00000	9511.30
30	Firestone***	Q.F./GSU	LA	GAS	0.30	8.00000	9511.60
31	Citgo***	Q.F./GSU	LA	GAS	75.00	8.00000	9586.60

APPENDIX B.1 (Continued)

ENTERGY LOUISIANA South: CONTROL AREA = 2

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	IMC-Agrico	Q.F./LP&L	LA	Sulpher	22.00	0.01900	22.00
2	Calciner Ind.	Q.F./LP&L	LA	Petr. Coke	27.00	0.01910	49.00
3	B.P. Oil	Q.F./LP&L	LA	Refinery Gas	19.15	0.02120	68.15
4	Waterford 3	LP&L	LA	NUCLEAR	1200.00	0.02210	1268.15
5	Nine Mile Point	LP&L	LA	GAS	1917.00	0.06420	3185.15
6	Little Gypsy	LP&L	LA	GAS	1251.00	0.06680	4436.15
7	Houma	City/Parish	LA	GAS	98.00	0.07251	4534.15
8	Waterford 1&2	LP&L	LA	GAS	891.00	0.07470	5425.15
9	Buras	LP&L	LA	GAS	21.00	0.21880	5446.15
10	Plaquemine	LEPA	LA	GAS	42.90	0.33913	5489.05
11	Thibodaux 9	LP&L	LA	GAS	21.00	8.00000	5510.05

ENTERGY LOUISIANA North: CONTROL AREA = 3

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	GAS	34.50	0.00750	34.50
2	Sterlington	LP&L	LA	GAS	480.00	0.07900	514.50
3	Ruston	Ruston	LA	GAS	81.00	0.08193	595.50
4	Monroe	LP&L	LA	GAS	137.00	8.00000	732.50

ENTERGY NEW ORLEANS: CONTROL AREA = 4

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Air Products	Q.F./NOPSI	LA	GAS	23.00	0.02370	23.00
2	Michoud	NOPSI	LA	GAS	959.00	0.06940	982.00
3	A.B. Patterson	NOPSI	LA	OIL	16.00	0.21440	998.00
4	Market Street	NOPSI	LA		103.00	8.00000	1101.00
5	A.B. Patterson	NOPSI	LA	GAS	133.00	8.00000	1234.00

APPENDIX B.1 (Continued)

CLECO North: CONTROL AREA = 5

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Rodemacher 2	CLECO	LA	COAL	558.00	0.02600	558.00
2	Dolet Hills	CLECO	LA	LIGNITE	650.37	0.03540	1208.37
3	Natchitoches	Natchitoches	LA	GAS	48.00	0.04021	1256.37
4	Rodemacher 1	CLECO	LA	GAS	445.50	0.06210	1701.87
5	Coughlin	CLECO	LA	GAS	368.10	0.07850	2069.97
6	Opelousas	Opelousas	LA	GAS	36.00	8.00000	2105.97

CLECO South: CONTROL AREA = 6

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Jeanerette Sugar*	Q.F./CLECO	LA	Bagasse	0.10	0.02190	0.10
2	Teche	CLECO	LA	GAS	427.90	0.05310	428.00
3	Franklin	CLECO	LA	GAS	10.00	8.00000	438.00

CLECO East: CONTROL AREA = 7

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
	No Generation Plants North of Lake Ponchatrain, just Demand.						

SWEPCO: CONTROL AREA = 8

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Pirkey 8	SWEPCO	TX	LIGNITE	619.38	0.02460	619.38
2	Dean Lumber*	Q.F./SWEPCO	TX	Wood	0.60	0.02570	619.98
3	Snider Industries*	Q.F./SWEPCO	TX	Wood	5.00	0.02590	624.98
4	Welsh 6	SWEPCO	TX	COAL	1674.00	0.04190	2298.98
5	Wilkes 5	SWEPCO	TX	GAS	881.52	0.05570	3180.50
6	Arsenal Hill 1	SWEPCO	LA	GAS	125.00	0.06060	3305.50
7	Knox Lee 3	SWEPCO	TX	GAS	499.50	0.06650	3805.00
8	Lieberman 2	SWEPCO	LA	GAS	277.27	0.08610	4082.27
9	Lone Star 4	SWEPCO	TX	GAS	50.00	0.09590	4132.27

APPENDIX B.1 (Continued)

CAJUN: CONTROL AREA = 9

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Big Cajun 2	CAJUN/GSU	LA	COAL	1735.10	0.02476	1735.10
2	Big Cajun 1	CAJUN	LA	GAS	230.00	0.05267	1965.10

LAFA: CONTROL AREA = 10

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Doc Bonin	LAFA	LA	GAS	276.00	0.01935	276.00

ALEX: CONTROL AREA = 11

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Hunter*	Alexandria	LA	GAS	171.50	0.10800	171.50

LEPA: CONTROL AREA = 12

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Morgan City	Morgan City	LA	GAS	65.60	0.05173	65.60

CONTRACT GENERATION: CONTROL AREA = C

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	TOTAL AVERAGE VARIABLE COST	CUMMULATIVE CAPACITY
1	Grand Gulf	System Energy	MS	NUCLEAR	344.63	0.02020	344.63
2	Sidney A. Murray, Jr.	LP&L	LA	HYDRO	192.00	0.06380	536.63

APPENDIX B.1 (Continued)

WHEELED POWER/IMPORTED GENERATION: CONTROL AREA = I

CONTROL AREA	COMPANY NAME	IMPORT HOST	ST.	MW CAPACITY	TOTAL AVERAGE VARIALBE COST	CUMMULATIVE CAPACITY
15	Southern Company	ENTERGY	MS	3853	0.04331	3853.00
16	MP&L	ENTERGY	MS	4079	0.06985	7932.00
17	AP&L	ENTERGY/SWEPCO	AR	4995	0.05404	12927.00
18	PSOK	SWEPCO	OK	1098	0.06927	14025.00
19	ERCOT	SWEPCO	TX	600	0.04891	14625.00

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX B.2

GENERATION FACILITY PRODUCTION DATA SEPARATED BY CONTROL AREA AND RANKED BY FUEL COST

ENTERGY GULF STATES: CONTROL AREA = 1

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	River Bend 1	GSU/CAJUN	LA	NUCLEAR	1022.30	0.02868	1022.30
2	Fina Oil & Chem.**	Q.F./GSU	TX	GAS	37.00	0.01400	1059.30
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	GAS	200.00	0.01570	1259.30
4	E.I. Dupont**	Q.F./GSU	TX	GAS	85.00	0.01650	1344.30
5	Roy S. Nelson 6	GSU	LA	COAL	430.00	0.04020	1774.30
6	Exxon Chemical**	Q.F./GSU	LA	GAS	84.00	0.01760	1858.30
7	Cogen Power	Q.F./GSU	TX	Waste Heat	5.00	0.01850	1863.30
8	Formosa Plastics	Q.F./GSU	LA	GAS	46.00	0.01910	1909.30
9	Engineered Carbons	Q.F./GSU	TX	Waste Heat	10.00	0.01980	1919.30
10	Vulcan Chemical	Q.F./GSU	LA	GAS	108.00	0.02010	2027.30
11	Huntsman Corp.	Q.F./GSU	TX	GAS	72.00	0.02030	2099.30
12	Clark Refining	Q.F./GSU	TX	GAS	84.80	0.02130	2184.10
13	Air Liquide	Q.F./GSU	TX	GAS	36.00	0.02140	2220.10
14	Dow Chemical	Q.F./GSU	LA	GAS	670.00	0.02220	2890.10
15	Borden Chemical	Q.F./GSU	LA	GAS	91.50	0.02240	2981.60
16	James River Paper	Q.F./GSU	LA	Paper ByProd.	57.50	0.02240	3039.10
17	Star Enterprises	Q.F./GSU	TX	GAS	164.00	0.02290	3203.10
18	Lewis Creek	GSU	TX	GAS	544.00	0.05390	3747.10
19	Sabine	GSU	TX	GAS	2051.00	0.05500	5798.10
20	BASF	Q.F./GSU	LA	GAS	36.60	0.02870	5834.70
21	Roy S. Nelson 3&4	GSU	LA	GAS	755.00	0.05980	6589.70
22	Willow Glen	GSU	LA	GAS	2178.00	0.06710	8767.70
23	Agrielectric	Q.F./GSU	LA	Rice Husks	12.50	0.03490	8780.20
24	New Roads	New Roads	LA	GAS	7.60	3.28619	8787.80
25	Rayne	Rayne	LA	GAS	2.50	0.32934	8790.30
26	LA Station #1 Un.4A	GSU	LA		129.00	8.00000	8919.30
27	Louisiana Station #1	GSU	LA	GAS	148.00	8.00000	9067.30
28	Neches	GSU	TX		269.00	8.00000	9336.30
29	Louisiana Station #2	GSU	LA	GAS	175.00	8.00000	9511.30
30	Firestone***	Q.F./GSU	LA	GAS	0.30	8.00000	9511.60
31	Citgo***	Q.F./GSU	LA	GAS	75.00	8.00000	9586.60

APPENDIX B.2 (Continued)

ENTERGY LOUISIANA South: CONTROL AREA = 2

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Waterford 3	LP&L	LA	NUCLEAR	1200.00	0.02210	1200.00
2	IMC-Agrico	Q.F./LP&L	LA	Sulpher	22.00	0.01900	1222.00
3	Calciner Ind.	Q.F./LP&L	LA	Petr. Coke	27.00	0.01910	1249.00
4	B.P. Oil	Q.F./LP&L	LA	Refinery Gas	19.15	0.02120	1268.15
5	Nine Mile Point	LP&L	LA	GAS	1917.00	0.06420	3185.15
6	Little Gypsy	LP&L	LA	GAS	1251.00	0.06680	4436.15
7	Waterford 1&2	LP&L	LA	GAS	891.00	0.07470	5327.15
8	Houma	City/Parish	LA	GAS	98.00	0.07251	5425.15
9	Plaquemine	LEPA	LA	GAS	42.90	0.33913	5468.05
10	Buras	LP&L	LA	GAS	21.00	0.21880	5489.05
11	Thibodaux 9	LP&L	LA	GAS	21.00	8.00000	5510.05

ENTERGY LOUISIANA North: CONTROL AREA = 3

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	GAS	34.50	0.00750	34.50
2	Ruston	Ruston	LA	GAS	81.00	0.08193	115.50
3	Sterlington	LP&L	LA	GAS	480.00	0.07900	595.50
4	Monroe	LP&L	LA	GAS	137.00	8.00000	732.50

ENTERGY NEW ORLEANS: CONTROL AREA = 4

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Air Products	Q.F./NOPSI	LA	GAS	23.00	0.02370	23.00
2	Michoud	NOPSI	LA	GAS	959.00	0.06940	982.00
3	A.B. Patterson	NOPSI	LA	OIL	16.00	0.21440	998.00
4	Market Street	NOPSI	LA		103.00	8.00000	1101.00
5	A.B. Patterson	NOPSI	LA	GAS	133.00	8.00000	1234.00

APPENDIX B.2 (Continued)

CLECO North: CONTROL AREA = 5

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Dolet Hills	CLECO	LA	LIGNITE	650.37	0.03540	650.37
2	Rodemacher 2	CLECO	LA	COAL	558.00	0.02600	1208.37
3	Rodemacher 1	CLECO	LA	GAS	445.50	0.06210	1653.87
4	Coughlin	CLECO	LA	GAS	368.10	0.07850	2021.97
5	Natchitoches	Natchitoches	LA	GAS	48.00	0.04021	2069.97
6	Opelousas	Opelousas	LA	GAS	36.00	8.00000	2105.97

CLECO South: CONTROL AREA = 6

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Jeanerette Sugar*	Q.F./CLECO	LA	Bagasse	0.10	0.02190	0.10
2	Teche	CLECO	LA	GAS	427.90	0.05310	428.00
3	Franklin	CLECO	LA	GAS	10.00	8.00000	438.00

CLECO East: CONTROL AREA = 7

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
	No Generation Plants North of Lake Ponchatrain, just Demand.						

SWEPCO: CONTROL AREA = 8

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Pirkey 8	SWEPCO	TX	LIGNITE	619.38	0.02460	619.38
2	Welsh 6	SWEPCO	TX	COAL	1674.00	0.04190	2293.38
3	Arsenal Hill 1	SWEPCO	LA	GAS	125.00	0.06060	2418.38
4	Dean Lumber*	Q.F./SWEPCO	TX	Wood	0.60	0.02570	2418.98
5	Snider Industries*	Q.F./SWEPCO	TX	Wood	5.00	0.02590	2423.98
6	Wilkes 5	SWEPCO	TX	GAS	881.52	0.05570	3305.50
7	Knox Lee 3	SWEPCO	TX	GAS	499.50	0.06650	3805.00
8	Lieberman 2	SWEPCO	LA	GAS	277.27	0.08610	4082.27
9	Lone Star 4	SWEPCO	TX	GAS	50.00	0.09590	4132.27

APPENDIX B.2 (Continued)

CAJUN: CONTROL AREA = 9

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Big Cajun 2	CAJUN/GSU	LA	COAL	1735.10	0.02476	1735.10
2	Big Cajun 1	CAJUN	LA	GAS	230.00	0.05267	1965.10

LAFA: CONTROL AREA = 10

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Doc Bonin	LAFA	LA	GAS	276.00	0.01935	276.00

ALEX: CONTROL AREA = 11

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Hunter*	Alexandria	LA	GAS	171.50	0.10800	171.50

LEPA: CONTROL AREA = 12

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Morgan City	Morgan City	LA	GAS	65.60	0.05173	65.60

CONTRACT GENERATION: CONTROL AREA = C

PLANT #	PLANT NAME	Q.F./HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
1	Grand Gulf	System Energy	MS	NUCLEAR	344.63	0.02020	344.63
2	Sidney A. Murray, Jr.	LP&L	LA	HYDRO	192.00	0.06380	536.63

APPENDIX B.2 (Continued)

WHEELED POWER/IMPORTED GENERATION: CONTROL AREA = I

CONTROL AREA	COMPANY NAME	IMPORT HOST	ST.	FUEL TYPE	MW CAPACITY	FUEL COST	CUMMULATIVE CAPACITY
15	Southern Company	ENTERGY	MS		3853.00	0.01860	3853.00
16	MP&L	ENTERGY	MS		4079.00	0.03283	7932.00
17	AP&L	ENTERGY/SWEPCO	AR		4995.00	0.02128	12927.00
18	PSOK	SWEPCO	OK		1098.00	0.02575	14025.00
19	ERCOT	SWEPCO	TX		600.00	0.02214	14625.00

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX B.3

INVESTOR-OWNED UTILITY GENERATION FACILITY COST AND SALES DATA

ENTERGY GULF STATES: CONTROL AREA = 1

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	River Bend 1	GSU/CAJUN	LA	3,095,227,159	4,512,000,000	0.4626	0.5876	6,843,285,000
2	Roy S. Nelson 6	GSU	LA	400,221,256	588,325,000	0.4626	0.5876	1,983,777,000
3	Lewis Creek	GSU	TX	64,992,832	56,360,000	0.4626	0.5876	2,416,151,000
4	Sabine	GSU	TX	349,631,298	229,207,000	0.4626	0.5876	8,517,695,000
5	Roy S. Nelson 3&4	GSU	LA	143,372,665	57,451,000	0.4626	0.5876	1,862,112,000
6	Willow Glen	GSU	LA	363,074,222	228,523,000	0.4626	0.5876	3,988,943,000
7	LA Station #1 Un.4A	GSU	LA	32,179,665	Unavailable	0.4626	0.5876	0
8	Louisiana Station #1	GSU	LA	40,306,160	Unavailable	0.4626	0.5876	0
9	Neches	GSU	TX	0	Unavailable	0.4626	0.5876	0
10	Louisiana Station #2	GSU	LA	0	Unavailable	0.4626	0.5876	0

ENTERGY LOUISIANA South: CONTROL AREA = 2

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Waterford 3	LP&L	LA	2,517,886,191	2,760,779,000	0.4793	1.00	8,926,846,000
2	Nine Mile Point	LP&L	LA	227,194,376	119,680,000	0.4793	1.00	5,702,647,000
3	Little Gypsy	LP&L	LA	119,366,688	39,786,000	0.4793	1.00	3,598,372,000
4	Waterford 1&2	LP&L	LA	143,725,713	123,480,000	0.4793	1.00	1,897,343,000
5	Buras	LP&L	LA	2,119,268	Unavailable	0.4793	1.00	3,709,000
6	Thibodaux 9	LP&L	LA	4,650,387	Unavailable	0.4793	1.00	0

ENTERGY LOUISIANA North: CONTROL AREA = 3

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Sterlington	LP&L	LA	69,695,996	16,609,000	0.0995	1.00	379,899,000
2	Monroe	LP&L	LA	21,298,491	Unavailable	0.0995	1.00	0

APPENDIX B.3 (Continued)

ENTERGY NEW ORLEANS: CONTROL AREA = 4

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Michoud	NOPSI	LA	112,715,311	36,904,000	0.2691	1.00	1,935,345,000
2	A.B. Patterson (Steam)	NOPSI	LA	22,068,263	Unavailable	0.2691	1.00	0
3	Market Street	NOPSI	LA	1,263,281	Unavailable	0.2691	1.00	0
4	A.B. Patterson (G.T.)	NOPSI	LA	1,474,282	Unavailable	0.2691	1.00	0

CLECO North: CONTROL AREA = 5

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Rodemacher 2	CLECO	LA	297,028,477	272,134,000	0.4562	1.00	3,187,051,000
2	Dolet Hills	CLECO	LA	491,838,254	527,800,000	0.4562	1.00	3,655,997,000
3	Rodemacher 1	CLECO	LA	67,704,001	74,802,000	0.4562	1.00	724,919,000
4	Coughlin	CLECO	LA	44,587,532	14,049,000	0.4562	1.00	232,386,000

CLECO South: CONTROL AREA = 6

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Teche	CLECO	LA	44,308,973	28,432,000	0.3824	1.00	1,209,205,000
2	Franklin	CLECO	LA	1,336,075	Unavailable	0.3824	1.00	0

CLECO East: CONTROL AREA = 7

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
	No Generation Plants North of Lake Ponchatrain, just Demand.							

APPENDIX B.3 (Continued)

SWEPCO: CONTROL AREA = 8

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Pirkey 8	SWEPCO	TX	435,387,599	1,260,099,000	0.5158	0.3003	4,269,747,000
2	Welsh 6	SWEPCO	TX	453,604,741	419,425,000	0.5158	0.3003	9,181,009,000
3	Wilkes 5	SWEPCO	TX	63,412,310	42,437,000	0.5158	0.3003	2,139,573,000
4	Arsenal Hill 1	SWEPCO	LA	15,440,088	340,080,000	0.5158	0.3003	146,420,000
5	Knox Lee 3	SWEPCO	TX	47,824,186	32,397,000	0.5158	0.3003	1,018,268,000
6	Lieberman 2	SWEPCO	LA	26,800,270	Unavailable	0.5158	0.3003	252,601,000
7	Lone Star 4	SWEPCO	TX	6,126,489	Unavailable	0.5158	0.3003	7,865,000

CAJUN: CONTROL AREA = 9

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Big Cajun 2	CAJUN/GSU	LA	223,924,172	1,196,000,000	0.5236	1.00	1,152,699,000
2	Big Cajun 1	CAJUN	LA	N/A	31,933,000	0.5236	1.00	282,895,000

CONTRACT GENERATION: CONTROL AREA = C

PLANT #	PLANT NAME	OWNER	ST.	COST-OF-PLANT	ORG. CONS. COST	LOAD FACTOR	LOUISIANA DIV. FACTOR	TOTAL KWH SOLD
1	Grand Gulf	System Energy	MS	3,411,393,906	3,642,691,000	0.8163	0.3100	8,301,980,000

NOTES:

1 LOUISIANA DIV. FACTOR = Diversity factor for Louisiana portion of Control Area Summer Peak Demand that cross state lines.
2 COST-OF-PLANT figures are Book Values for 1996 unless where noted.
3 COST-OF-PLANT figures include: Land and Land Rights, Structures and Improvements, and Equipment Costs.

APPENDIX C

TRANSMISSION INTERCONNECTION DATA

APPENDIX C.1
ESTIMATE FOR POSTAGE STAMP TRANSMISSION INTERCONNECTION COST

CONTROL AREA #	ELECTRIC UTILITY COMPANY	SUMMER PEAK MW DEMAND	AVG. COMPANY TRANSMISSION COST PER MWh	WEIGHTED AVG. COST ALLOCATION
1	GSU	6633.99	1.57	0.5326
2	LP&L South	4603.70	0.72	0.1695
3	LP&L North	1346.58	0.72	0.0496
4	NOPSI	1153.99	1.14	0.0673
5	CLECO North	942.20	1.32	0.0636
6	CLECO South	417.60	1.32	0.0282
7	CLECO East	384.10	1.32	0.0259
8	SWEPCO	3555.56	1.07	0.1945
9	CAJUN	0.00	0.00	0.0000
10	LAFA	367.00	2.12	0.0398
11	ALEX	111.20	1.32	0.0075
12	LEPA	39.50	1.32	0.0027
	TOTALS	19555.42		1.1812

Average Postage Rate = $1.18/MWh

NOTE:
The Postage Stamp for Transmission Interconnection Costs is a summer peak system weighted average of average company transmission costs.

APPENDIX C.2

TRANSMISSION INTERCONNECTION SYSTEM PARAMETERS

ENTERGY GULF STATES to ENTERGY LOUISIANA South INTERCONNECTIONS (1 <=> 2)

LINE #	INTERCONNECTION ENDPOINTS	V I-I	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	LP&L S. Waterfo (1452) - GSU WGlen (1419)	500	1200	0.00070	0.01094		0.01096	27.40593
2	LP&L S. Bgatel (1493) - GSU Conwy (1297)	230	436	0.00173	0.01192		0.01204	6.37175
3	!!LP&L S. - GSU: PARALLEL LINES!!	230	924				0.00291	1.54192
	LP&L S. Evgren (1461) - GSU WGlen (1420)	230	462	0.00070	0.00590	0.00594		
	LP&L S. Evgren (1461) - GSU WGlen (1420)	230	462	0.00050	0.00570	0.00572		
4	GSU Gonzl (1331) - LP&L S. Sorxfm (1520)	138	130	0.00738	0.02035		0.02165	4.12243
5	GSU Addis (1267) - LP&L S. Plaqmn (1463)	138/115	60	0.02287	0.11756		0.11976	15.83878

ENTERGY GULF STATES to ENTERGY LOUISIANA North INTERCONNECTION (1 <=> 3)

LINE #	INTERCONNECTION ENDPOINTS	V I-I	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	GSU Hartbrg (897) - LP&L N. MtOliv (1968)	500	1732	0.00266	0.03965		0.03974	99.34781

ENTERGY GULF STATES to CLECO North INTERCONNECTIONS (1 <=> 5)

LINE #	INTERCONNECTION ENDPOINTS	V I-I	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	GSU Nelson (1027) - CLECO N. Penton (239)	230	333	0.00340	0.02170		0.02196	11.61935
2	GSU Toledo (888) - CLECO N. Leesv (209)	138	145	0.03630	0.09450		0.10123	19.27864
3	GSU Toledo (888) - CLECO N. VanPlyTap (298)	138	145	0.01670	0.06510		0.06721	12.79907
4	CLECO N. Cooper (217) - GSU Bonweir (772)	138	137	0.06020	0.17010		0.18044	34.36271
5	CLECO N. Derid (208) - GSU Nelson (1028)	138	289	0.03140	0.12380		0.12772	24.32300
6	CLECO N. Plais (205) - GSU Champne (1193)	138	263	0.01030	0.03860		0.03995	7.60819

APPENDIX C.2 (Continued)

ENTERGY GULF STATES to CLECO South INTERCONNECTIONS (1 <=> 6)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	GSU Buwhse (1231) - CLECO S. Ivanhoe (214)	138	141	0.00970	0.02550		0.02728	5.19570
2	GSU Richard (1168) - CLECO S. Eunice (203)	138	296	0.00460	0.01790		0.01848	3.51964
3	GSU Richard (1168) - CLECO S. Habetz (201)	138	296	0.00960	0.03700		0.03823	7.27959
4	CLECO S. Hopkins (213) - GSU Moril (1228)	138	253	0.00130	0.00950		0.00959	1.82604
5	CLECO S. Longfl (270) - GSU StMartn (1244)	69	39	0.00037	0.00054		0.00065	0.03117
6	CLECO S. Longfl (270) - GSU LG25OP (1245)	69	39	0.01455	0.02088		0.02545	1.21165
7	CLECO S. BBrid (228) - GSU Anslabu (1233)	69	58	0.01910	0.03490		0.03978	1.89415

ENTERGY GULF STATES to SWEPCO INTERCONNECTION (1 <=> 8)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	GSU Grimes (713) - SWEPCO Crocket (2950)	345	1315	0.00316	0.03289		0.03304	39.32759

ENTERGY GULF STATES to CAJUN INTERCONNECTIONS (1 <=> 9)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	GSU Fancy (1319) - CAJUN Cajun2 (452)	500	2048	0.00004	0.00070		0.00070	1.75285
2	GSU Webre (1425) - CAJUN Cajun2 (452)	500	2598	0.00038	0.00574		0.00575	14.38141
3	GSU Addis (1266) - CAJUN Cajun1 (451)	230	566	0.00401	0.02800		0.02829	14.96313
4	GSU Watloo (1422) - CAJUN Cajun1 (451)	230	685	0.00017	0.00120		0.00121	0.64114

ENTERGY GULF STATES to LAFA INTERCONNECTIONS (1 <=> 10)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	GSU Cecelia (1236) - LAFA Bonin (404)	138	144	0.02140	0.05741		0.06127	11.66803
2	GSU Scott (1170) - LAFA Bonin (404)	138	224	0.00359	0.01523		0.01565	2.97989

APPENDIX C.2 (Continued)

ENTERGY GULF STATES to FRKLIN (MP&L Bus) INTERCONNECTION (1 <= 14)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	GSU Mcknt (1365) - MP&L Frklin (1864)	500	1732	0.00080	0.01210		0.01213	30.31604

ENTERGY GULF STATES IMPORTS from Southern Company (SC) INTERCONNECTION (1 <= 15)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	SC Daniel (15035) - GSU Mcknt (1365)	500	2598	0.00212	0.03273		0.03280	81.99647

ENTERGY LOUISIANA South to ENTERGY NEW ORLEANS INTERCONNECTIONS (2 <=> 4)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	NOPSI Micho (1579) - LP&L S. Slidel (1519)	230	643	0.00280	0.03090		0.03103	16.41307
2	NOPSI Micho (1579) - LP&L S. Packai (1573)	230	639	0.00090	0.00980		0.00984	5.20602
3	NOPSI Micho (1579) - LP&L S. Arabi (1574)	230	760	0.00080	0.00990		0.00993	5.25417
4	NOPSI Tricu (1592) - LP&L S. Arabi (1574)	230	760	0.00010	0.00140		0.00140	0.74249
5	NOPSI Joliet (1609) - LP&L S. SPort (1529)	230	640	0.00029	0.00300		0.00301	1.59440
6	LP&L S. 9Mile (1552) - NOPSI Derbi (1603)	230	640	0.00080	0.00871		0.00875	4.62698
7	LP&L S. 9Mile (1552) - NOPSI Napol (1607)	230	760	0.00060	0.00700		0.00703	3.71658
8	LP&L S. Chlmet (1571) - NOPSI Pater (1588)	115	200	0.00580	0.03970		0.04012	5.30606
9	LP&L S. Prstap (1528) - NOPSI AveC (1608)	115	320	0.00030	0.00230		0.00232	0.30675

ENTERGY LOUISIANA South to CLECO South INTERCONNECTION (2 <=> 6)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO S. Ramos (273) - LP&L S. Gibson (1469)	138/115	228	0.00802	0.03956		0.04036	5.33824

APPENDIX C.2 (Continued)

ENTERGY LOUISIANA South to CLECO East INTERCONNECTIONS (2 <=> 7)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO E. Madis (240) - LP&L S. Gypsy (1485)	230	454	0.00720	0.05150		0.05200	27.50846
2	CLECO E. Madis (240) - LP&L S. Pntchtl (1496)	230	458	0.00382	0.02810		0.02836	15.00163
3	CLECO E. SSlid (237) - LP&L S. Slidel (1519)	230	800	0.00000	0.00100		0.00100	0.52900
4	CLECO E. Ramsay (291) - LP&L S. Bogalus (1509)	230	454	0.00492	0.03885		0.03916	20.71580
5	CLECO E. Frankln (296) - LP&L S. Frankln (1506)	115	100	0.00000	0.00100		0.00100	0.13225

ENTERGY LOUISIANA South to FRKLIN (MP&L Bus) INTERCONNECTION (2 <= 14)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	LP&L S. Bogalus (1510) - MP&L Frklin (1864)	500	1732	0.00090	0.01640		0.01642	41.06169

ENTERGY LOUISIANA South IMPORTS from Southern Company INTERCONNECTIONS (2 <= 15)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	SC Logtwn (15032) - LP&L S./CAJUN FrnBra (508)	230	797	0.00102	0.01267		0.01271	6.72411
2	SC Hatbg (15030) - LP&L S. Bogalus (1509)	230	458	0.01070	0.07920		0.07992	42.27743

ENTERGY LOUISIANA South IMPORTS from MP&L INTERCONNECTIONS (2 <= 16)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L Gilbr (1899) - LP&L S. Amite (1504)	115	108	0.05250	0.15100		0.15987	21.14232
2	MP&L Coln.P (1908) - LP&L S. Kentwd (1505)	115	69	0.06035	0.09615		0.11352	15.01311
3	MP&L Dexter (1905) - LP&L S. Boglsa (1507)	115	120	0.02480	0.13330		0.13559	17.93143

APPENDIX C.2 (Continued)

ENTERGY LOUISIANA North to CLECO North INTERCONNECTIONS (3 <=> 5)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO N. Clarn (222) - LP&L N. Montgy (1921)	230	414	0.00300	0.01910		0.01933	10.22777
2	CLECO N. Colfax (227) - LP&L N. Montgy (1921)	230	414	0.00380	0.02390		0.02420	12.80191
3	CLECO N. Beacr (207) - LP&L N. Bvrcrk (1911)	138/115	93	0.00000	0.05000		0.05000	6.61250
4	CLECO N. Fisher (232) - LP&L N. Fisher (1920)	138/115	83	0.00220	0.03060		0.03068	4.05730
5	CLECO N. Leesv (209) - LP&L N. FtPolk (1996)	138/115	100	0.00000	0.00100		0.00100	0.13225
6	CLECO N. Carroll (212) - LP&L N. Ringld (1973)	138/115	125	0.02569	0.09173		0.09526	12.59807
7	CLECO N. Marksv (218) - LP&L N. Marksv (1997)	138/115	100	0.00000	0.00100		0.00100	0.13225

ENTERGY LOUISIANA North to SWEPCO INTERCONNECTION (3 <=> 8)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	SWEPCO Minden (2739) - LP&L N. Minden (1976)	115	99	0.00690	0.01870		0.01993	2.63606

ENTERGY LOUISIANA North IMPORTS FROM BWILSON (MP&L Bus) INTERCONNECTIONS (3 <= 13)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L BWlsn (1822) - LP&L N. Sterl (1954)	500	1732	0.00120	0.01770		0.01774	44.35158
2	MP&L BWlsn (1823) - LP&L N. Talula (1960)	115	199	0.01800	0.12800		0.12926	17.09456

ENTERGY LOUISIANA North to CONTRACT GENERATION INTERCONNECTION (3 <= C2)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	LP&L N. Plant (1922) - MURRAY Murrla (1994)	115	320	0.01680	0.20070		0.20140	26.63540

APPENDIX C.2 (Continued)

ENTERGY LOUISIANA North IMPORTS from MP&L INTERCONNECTIONS (3 <= 16)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L Natses (1854) - LP&L N. Redgum (1923)	115	87	0.03210	0.09110		0.09659	12.77402
2	MP&L Nat-In (1859) - LP&L N. Plant (1922)	115	231	0.00364	0.03021		0.03043	4.02417

ENTERGY LOUISIANA North IMPORTS from AP&L INTERCONNECTIONS (3 <= 17)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	AP&L EldEHV (2073) - LP&L N. Sterl (1954)	500	1732	0.00075	0.01054		0.01057	26.41663
2	AP&L EldEHV (2073) - LP&L N. MtOliv (1968)	500	1039	0.00034	0.01143		0.01144	28.58764
3	AP&L Huttig (2065) - LP&L N./CAJUN Marion (462)	115	98	0.02410	0.06660		0.07083	9.36678
4	AP&L Eudra (2027) - LP&L N./CAJUN Chksaw (465)	115	80	0.01320	0.06021		0.06164	8.15188
5	AP&L Cros-N (2008) - LP&L N. Sterl (1952)	115	80	0.07479	0.19519		0.20903	27.64395
6	AP&L Meridn (2083) - LP&L N. Sterl (1952)	115	68	0.11716	0.18380		0.21797	28.82592
7	AP&L Eld-Up (2091) - LP&L N. Bernic (1971)	115	159	0.02282	0.13074		0.13272	17.55177
8	AP&L Taylor (2058) - LP&L N. Springh (1977)	115	120	0.00950	0.04266		0.04370	5.77998
9	AP&L Emersn (2026) - LP&L N. Haynvl (1979)	115	114	0.02035	0.05951		0.06289	8.31763

CLECO North to CLECO South INTERCONNECTIONS (5 <=> 6)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO N. Cocodr (233) - CLECO S. Vilplt (246)	230	829	0.00130	0.01230		0.01237	6.54294
2	CLECO N. Cough (204) - CLECO S. Manuel (248)	138	151	0.01380	0.05370		0.05544	10.55891

CLECO North to SWEPCO INTERCONNECTIONS (5 <=> 8)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO N. DolHill (292) - SWEPCO SwShv (2723)	345	962	0.00160	0.02270		0.02276	27.08571
2	CLECO N. Mansf (211) - SWEPCO Wallake (2728)	138	191	0.01900	0.09040		0.09238	17.59191

APPENDIX C.2 (Continued)

CLECO North to ALEXANDRIA INTERCONNECTIONS (5 <=> 11)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO N. TwBrdg - ALEX TBAlex	230/138	454	0.00000	0.00100		0.00100	0.19044
2	CLECO N. Pineville - ALEX Hunter	138	504	0.00220	0.00930		0.00956	1.81997

CLECO South to LAFAYETTE INTERCONNECTIONS (6 <=> 10)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO S. Wstfork (261) - LAFA PMouton (410)	230	829	0.00250	0.02270		0.02284	12.08091
2	LAFA Flander (401) - CLECO S. Flander (235)	230/138	336	0.00070	0.02170		0.02171	4.13470
3	CLECO S. Nicktap (269) - LAFA Elkslaf (413)	69	33	0.09350	0.08480		0.12623	6.00967

CLECO South to LEPA INTERCONNECTION (6 <=> 12)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	CLECO S. Ramos (273) - LEPA Mrgncty (441)	138	105	0.00500	0.01370		0.01458	2.77736

SWEPCO IMPORTS from AP&L INTERCONNECTIONS (8 <= 17)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	AP&L EldEHV (2072) - SWEPCO Longwd (2695)	345	900	0.00450	0.04930		0.04950	58.92327
2	AP&L Murfre (2170) - SWEPCO Snashvl (2615)	138	96	0.02920	0.08600		0.09082	17.29615
3	AP&L Patmos (2081) - SWEPCO Hope (2553)	115	159	0.01390	0.06600		0.06745	8.91998

APPENDIX C.2 (Continued)

SWEPCO IMPORTS from PUBLIC SERVICE COMPANY OF OKLAHOMA INTERCONNECTIONS (8 <= 18)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	PSOK Valiant (4283) - SWEPCO Lydia (2830)	345	717	0.00240	0.02130		0.02143	25.51275
2	PSOK CraigJt (4261) - SWEPCO Ashwest (2505)	138	190	0.01680	0.13340		0.13445	25.60536
3	PSOK CraigJt (4261) - SWEPCO Dequeen (2528)	138	191	0.01100	0.05380		0.05491	10.45764

SWEPCO IMPORTS from ERCOT INTERCONNECTION (8 <= 19)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	ERCOT EastDC (9992) - SWEPCO Welsh (2918)	345	600	0.00000	0.00100		0.00100	1.19025

CONTRACT GENERATION to BWILSON (MP&L Bus) INTERCONNECTION (13 <= C1)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L BWlsn (1822) - SER GGulf (1837)	500	2598	0.00030	0.00500		0.00501	12.52248

INTERNAL BUS CONNECTION to BWILSON (MP&L Bus) INTERCONNECTION (B <= 13)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L BWlsn (1822) - MP&L BWlsn (1823)	500/115	560	0.00060	0.03070		0.03071	4.06085

Louisiana Power Grid IMPORTS from MP&L through BWILSON (MP&L Bus) INTERCONNECTION (13 <= 16)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L R.Bras (1814) - MP&L BWlsn (1822)	500	1732	0.00050	0.00830		0.00832	20.78762

APPENDIX C.2 (Continued)

CONTRACT GENERATION to FRKLIN (MP&L Bus) INTERCONNECTION (14 <= C1)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L Frklin (1864) - SER GGulf (1837)	500	1732	0.00060	0.01010		0.01012	25.29452

Louisiana Power Grid IMPORTS from MP&L through FRKLIN (MP&L Bus) INTERCONNECTION (14 <= 16)

LINE #	INTERCONNECTION ENDPOINTS	V l-l	MW CAP.	R p.u.	X p.u.	SERIES/ PARALLEL	Z p.u.	IMPEDANCE
1	MP&L R.Bras (1814) - MP&L Frklin (1864)	500	1732	0.00080	0.01360		0.01362	34.05877

APPENDIX C.2 (Continued)

NOTES:

1 The numbers in parenthsis beside each interconnection title denote specific Control Areas. They are:
  Entergy Gulf States (GSU) = Control Area 1,
  Entergy Louisiana South (LP&L S.) = Control Area 2,
  Entergy Louisiana North (LP&L N.)= Control Area 3,
  Entergy New Orleans (NOPSI) = Control Area 4,
  CLECO North = Control Area 5,
  CLECO South = Control Area 6,
  CLECO East = Control Area 7,
  SWEPCO = Control Area 8,
  CAJUN = Control Area 9,
  Lafayette Utilities (LAFA) = Control Area 10,
  City of Alexandria (ALEX) = Control Area 11,
  LEPA (Morgan City) = Control Area 12,
  BWILSON (MP&L Bus) = Control Area 13,
  FRKLIN (MP&L Bus) = Control Area 14,
  CONTRACT GENERATION (Grand Gulf & Murray Hydro) = Control Area C, and
  IMPORTED GENERATION where:
    Southern Companies = Control Area 15,
    MP&L = Control Area 16,
    AP&L = Control Area 17,
    PSOK = Control Area 18, and
    ERCOT = Control Area 19.

2 The numbers beside each interconnection endpoint correspond to SPP load points.

3 A Unity Power Factor is assumed for modeling.

4 The system is in Normal Operation.

5 All Interconnection Data was taken from the 1996 Summer Peak Load Flow Model by SPP and verified by System Maps at the Louisiana Public Service Commission.

6 Per Unit Impedances (Z) are on a 3-phase 100 MVA base.

APPENDIX D

SYSTEM DEMAND DATA

APPENDIX D.1
1996 SUMMER PEAK DEMAND WITH SPINNING RESERVES

CONTROL AREA #	ELECTRIC UTILITY COMPANY	PEAK DEMAND	REQUIRED SPINNING RESERVES	TOTAL PEAK DEMAND IN MW
1	Entergy Gulf States	6,633.99	995.10	7,629.09
2	Entergy Louisiana South	4,603.70	690.56	5,294.26
3	Entergy Louisiana North	1,346.58	201.99	1,548.57
4	Entergy New Orleans	1,153.99	173.10	1,327.09
5	CLECO North	942.20	141.33	1,083.53
6	CLECO South	417.60	62.64	480.24
7	CLECO East	384.10	57.62	441.72
8	SWEPCO (affecting LA)	3,555.56	533.33	4,088.89
9	CAJUN	0.00	0.00	0.00
10	Lafayette Utilities	367.00	55.05	422.05
11	City of Alexandria	111.20	16.68	127.88
12	LEPA	39.50	5.93	45.43
	TOTALS	**19,555.42**	**2,933.31**	**22,488.73**

APPENDIX D.2
1996 WINTER PEAK DEMAND WITH SPINNING RESERVES

CONTROL AREA #	ELECTRIC UTILITY COMPANY	PEAK DEMAND	REQUIRED SPINNING RESERVES	TOTAL PEAK DEMAND IN MW
1	Entergy Gulf States	4,945.52	741.83	5,687.35
2	Entergy Louisiana South	3,573.90	536.09	4,109.99
3	Entergy Louisiana North	987.00	148.05	1,135.05
4	Entergy New Orleans	787.02	118.05	905.07
5	CLECO North	702.20	105.33	807.53
6	CLECO South	283.40	42.51	325.91
7	CLECO East	259.90	38.98	298.89
8	SWEPCO (affecting LA)	2,848.50	427.28	3,275.78
9	CAJUN	0.00	0.00	0.00
10	Lafayette Utilities	269.00	40.35	309.35
11	City of Alexandria	83.40	12.51	95.91
12	LEPA	30.50	4.58	35.08
	TOTALS	**14,770.34**	**2,215.55**	**16,985.89**

NOTES:

1 Spinning Reserves are estimated to be 15% of Peak Demand.
2 Peak demand within each area includes the demand of all R.U.S. Cooperatives within the service area.

APPENDIX E

ECONOMIC DISPATCH EXPERIMENTATION RESULTS

(Results from the LaDEUX Model)

APPENDIX E.1
ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #1

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440.50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	53.34%	12544.59
38	ERCOT	SWEPCO	TX	600.00	0.04891	100.00%	13144.59
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	13210.19
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	13440.19
41	Teche	CLECO	LA	427.90	0.05310	100.00%	13868.09
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	14412.09
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	41.14%	16467.03
44	Sabine	GSU	TX	2051.00	0.05500	100.00%	18518.03
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	100.00%	19399.55
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	100.00%	20154.55
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	93.34%	20271.23
48	Rodemacher 1	CLECO	LA	445.50	0.06210	0.00%	20271.23
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	0.00%	20271.23
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	100.00%	22188.23
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	0.00%	22188.23
52	Little Gypsy	LP&L	LA	1251.00	0.06680	66.88%	23024.90
53	Willow Glen	GSU	LA	2178.00	0.06710	0.00%	23024.90
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	23024.90
55	Michoud	NOPSI	LA	959.00	0.06940	0.00%	23024.90
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	23024.90
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	23024.90
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	23024.90
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	23024.90
60	Sterlington	LP&L	LA	480.00	0.07900	0.00%	23024.90
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	23024.90
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	23024.90
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	23024.90
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	23024.90
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	23024.90
66	Buras	LP&L	LA	21.00	0.21880	0.00%	23024.90
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	23024.90
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	23024.90

APPENDIX E.1 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	23024.90
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	23024.90
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	23024.90
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	23024.90
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	23024.90
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	23024.90
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	23024.90
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	23024.90
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	23024.90
78	Neches	GSU	TX	269.00	8.00000	0.00%	23024.90
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	23024.90
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	23024.90
81	Citgo***	Q.F./GSU	LA	75.00	8.00000	0.00%	23024.90

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line.
(i.e. a mothballed or unavailable unit)

APPENDIX E.2

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #2

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440.50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agnco	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	42.08%	12110.74
38	ERCOT	SWEPCO	TX	600.00	0.04891	100.00%	12710.74
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	12776.34
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	13006.34
41	Teche	CLECO	LA	427.90	0.05310	100.00%	13434.24
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	13978.24
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	14.30%	14692.53
44	Sabine	GSU	TX	2051.00	0.05500	100.00%	16743.53
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	36.72%	17067.22
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	0.00%	17067.22
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	0.00%	17067.22
48	Rodemacher 1	CLECO	LA	445.50	0.06210	0.00%	17067.22
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	0.00%	17067.22
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	14.78%	17350.55
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	0.00%	17350.55
52	Little Gypsy	LP&L	LA	1251.00	0.06680	0.00%	17350.55
53	Willow Glen	GSU	LA	2178.00	0.06710	0.00%	17350.55
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	17350.55
55	Michoud	NOPSI	LA	959.00	0.06940	0.00%	17350.55
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	17350.55
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	17350.55
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	17350.55
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	17350.55
60	Sterlington	LP&L	LA	480.00	0.07900	0.00%	17350.55
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	17350.55
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	17350.55
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	17350.55
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	17350.55
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	17350.55
66	Buras	LP&L	LA	21.00	0.21880	0.00%	17350.55
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	17350.55
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	17350.55

APPENDIX E.2 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	17350.55
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	17350.55
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	17350.55
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	17350.55
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	17350.55
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	17350.55
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	17350.55
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	17350.55
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	17350.55
78	Neches	GSU	TX	269.00	8.00000	0.00%	17350.55
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	17350.55
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	17350.55
81	Citgo***	Q.F./GSU	LA	75.00	8.00000	0.00%	17350.55

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.3

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #3

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2*	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440 50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	0.00%	10489.40
38	ERCOT	SWEPCO	TX	600.00	0.04891	0.00%	10489.40
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	10555.00
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	10785.00
41	Teche	CLECO	LA	427.90	0.05310	100.00%	11212.90
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	11756.90
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	0.00%	11756.90
44	Sabine	GSU	TX	2051.00	0.05500	100.00%	13807.90
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	100.00%	14689.42
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	100.00%	15444.42
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	100.00%	15569.42
48	Rodemacher 1	CLECO	LA	445.50	0.06210	100.00%	16014.92
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	33.21%	16078.68
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	100.00%	17995.68
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	100.00%	18495.18
52	Little Gypsy	LP&L	LA	1251.00	0.06680	100.00%	19746.18
53	Willow Glen	GSU	LA	2178.00	0.06710	90.15%	21709.65
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	21709.65
55	Michoud	NOPSI	LA	959.00	0.06940	100.00%	22668.65
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	22668.65
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	22668.65
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	22668.65
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	22668.65
60	Sterlington	LP&L	LA	480.00	0.07900	0.00%	22668.65
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	22668.65
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	22668.65
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	22668.65
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	22668.65
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	22668.65
66	Buras	LP&L	LA	21.00	0.21880	0.00%	22668.65
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	22668.65
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	22668.65

APPENDIX E.3 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	22668.65
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	22668.65
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	22668.65
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	22668.65
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	22668.65
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	22668.65
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	22668.65
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	22668.65
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	22668.65
78	Neches	GSU	TX	269.00	8.00000	0.00%	22668.65
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	22668.65
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	22668.65
81	Citgo***	O.F./GSU	LA	75.00	8.00000	0.00%	22668.65

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.4

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #4

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440.50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	0.00%	10489.40
38	ERCOT	SWEPCO	TX	600.00	0.04891	0.00%	10489.40
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	10555.00
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	10785.00
41	Teche	CLECO	LA	427.90	0.05310	100.00%	11212.90
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	11756.90
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	0.00%	11756.90
44	Sabine	GSU	TX	2051.00	0.05500	100.00%	13807.90
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	100.00%	14689.42
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	50.84%	15073.26
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	100.00%	15198.26
48	Rodemacher 1	CLECO	LA	445.50	0.06210	0.00%	15198.26
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	4.28%	15206.48
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	100.00%	17123.48
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	0.00%	17123.48
52	Little Gypsy	LP&L	LA	1251.00	0.06680	0.00%	17123.48
53	Willow Glen	GSU	LA	2178.00	0.06710	0.00%	17123.48
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	17123.48
55	Michoud	NOPSI	LA	959.00	0.06940	0.00%	17123.48
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	17123.48
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	17123.48
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	17123.48
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	17123.48
60	Sterlington	LP&L	LA	480.00	0.07900	0.00%	17123.48
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	17123.48
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	17123.48
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	17123.48
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	17123.48
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	17123.48
66	Buras	LP&L	LA	21.00	0.21880	0.00%	17123.48
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	17123.48
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	17123.48

APPENDIX E.4 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	17123.48
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	17123.48
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	17123.48
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	17123.48
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	17123.48
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	17123.48
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	17123.48
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	17123.48
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	17123.48
78	Neches	GSU	TX	269.00	8.00000	0.00%	17123.48
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	17123.48
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	17123.48
81	Citgo***	Q.F./GSU	LA	75.00	8.00000	0.00%	17123.48

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.5

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #5

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440.50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	50.17%	12422.45
38	ERCOT	SWEPCO	TX	600.00	0.04891	100.00%	13022.45
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	13088.05
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	13318.05
41	Teche	CLECO	LA	427.90	0.05310	100.00%	13745.95
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	14289.95
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	35.04%	16040.20
44	Sabine	GSU	TX	2051.00	0.05500	100.00%	18091.20
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	100.00%	18972.72
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	100.00%	19727.72
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	90.82%	19841.24
48	Rodemacher 1	CLECO	LA	445.50	0.06210	0.00%	19841.24
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	0.00%	19841.24
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	100.00%	21758.24
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	0.00%	21758.24
52	Little Gypsy	LP&L	LA	1251.00	0.06680	93.94%	22933.43
53	Willow Glen	GSU	LA	2178.00	0.06710	0.00%	22933.43
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	22933.43
55	Michoud	NOPSI	LA	959.00	0.06940	0.00%	22933.43
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	22933.43
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	22933.43
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	22933.43
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	22933.43
60	Sterlington	LP&L	LA	480.00	0.07900	0.00%	22933.43
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	22933.43
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	22933.43
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	22933.43
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	22933.43
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	22933.43
66	Buras	LP&L	LA	21.00	0.21880	0.00%	22933.43
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	22933.43
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	22933.43

APPENDIX E.5 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	22933.43
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	22933.43
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	22933.43
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	22933.43
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	22933.43
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	22933.43
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	22933.43
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	22933.43
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	22933.43
78	Neches	GSU	TX	269.00	8.00000	0.00%	22933.43
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	22933.43
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	22933.43
81	Citgo***	Q.F./GSU	LA	75.00	8.00000	0.00%	22933.43

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.6

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #6

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440.50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	39.92%	12027.52
38	ERCOT	SWEPCO	TX	600.00	0.04891	100.00%	12627.52
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	12693.12
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	12923.12
41	Teche	CLECO	LA	427.90	0.05310	100.00%	13351.02
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	13895.02
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	12.93%	14540.87
44	Sabine	GSU	TX	2051.00	0.05500	93.86%	16465.94
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	45.25%	16864.83
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	0.00%	16864.83
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	0.00%	16864.83
48	Rodemacher 1	CLECO	LA	445.50	0.06210	0.00%	16864.83
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	0.00%	16864.83
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	24.14%	17327.59
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	0.00%	17327.59
52	Little Gypsy	LP&L	LA	1251.00	0.06680	0.00%	17327.59
53	Willow Glen	GSU	LA	2178.00	0.06710	0.00%	17327.59
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	17327.59
55	Michoud	NOPSI	LA	959.00	0.06940	0.00%	17327.59
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	17327.59
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	17327.59
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	17327.59
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	17327.59
60	Sterlington	LP&L	LA	480.00	0.07900	0.00%	17327.59
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	17327.59
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	17327.59
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	17327.59
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	17327.59
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	17327.59
66	Buras	LP&L	LA	21.00	0.21880	0.00%	17327.59
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	17327.59
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	17327.59

APPENDIX E.6 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	17327.59
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	17327.59
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	17327.59
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	17327.59
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	17327.59
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	17327.59
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	17327.59
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	17327.59
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	17327.59
78	Neches	GSU	TX	269.00	8.00000	0.00%	17327.59
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	17327.59
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	17327.59
81	Citgo***	Q.F./GSU	LA	75.00	8.00000	0.00%	17327.59

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.7
ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #7

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440.50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	0.00%	10489.40
38	ERCOT	SWEPCO	TX	600.00	0.04891	0.00%	10489.40
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	10555.00
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	10785.00
41	Teche	CLECO	LA	427.90	0.05310	100.00%	11212.90
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	11756.90
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	0.00%	11756.90
44	Sabine	GSU	TX	2051.00	0.05500	100.00%	13807.90
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	100.00%	14689.42
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	100.00%	15444.42
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	100.00%	15569.42
48	Rodemacher 1	CLECO	LA	445.50	0.06210	100.00%	16014.92
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	30.88%	16074.21
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	100.00%	17991.21
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	100.00%	18490.71
52	Little Gypsy	LP&L	LA	1251.00	0.06680	100.00%	19741.71
53	Willow Glen	GSU	LA	2178.00	0.06710	80.54%	21495.87
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	21495.87
55	Michoud	NOPSI	LA	959.00	0.06940	100.00%	22454.87
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	22454.87
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	22454.87
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	22454.87
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	22454.87
60	Sterlington	LP&L	LA	480.00	0.07900	38.79%	22641.06
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	22641.06
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	22641.06
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	22641.06
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	22641.06
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	22641.06
66	Buras	LP&L	LA	21.00	0.21880	0.00%	22641.06
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	22641.06
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	22641.06

APPENDIX E.7 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	22641.06
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	22641.06
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	22641.06
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	22641.06
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	22641.06
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	22641.06
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	22641.06
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	22641.06
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	22641.06
78	Neches	GSU	TX	269.00	8.00000	0.00%	22641.06
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	22641.06
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	22641.06
81	Citgo***	Q.F./GSU	LA	75.00	8.00000	0.00%	22641.06

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.8
ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #8

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Minden	Minden	LA	34.50	0.00750	100.00%	34.50
2	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	71.50
3	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	271.50
4	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	356.50
5	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	440.50
6	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	445.50
7	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	467.50
8	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	494.50
9	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	540.50
10	Doc Bonin	LAFA	LA	276.00	0.01935	100.00%	816.50
11	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	826.50
12	Vulcan Chemical	O.F./GSU	LA	108.00	0.02010	100.00%	934.50
13	Grand Gulf	System Energy	MS	345.00	0.02020	100.00%	1279.50
14	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	1351.50
15	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	1370.65
16	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	1455.45
17	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	1491.45
18	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	1491.55
19	Waterford 3	LP&L	LA	1200.00	0.02210	100.00%	2691.55
20	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	3361.55
21	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	3453.05
22	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	3510.55
23	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	3674.55
24	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	3697.55
25	Pirkey 8	SWEPCO	TX	619.38	0.02460	100.00%	4316.93
26	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.02476	100.00%	6052.03
27	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	6052.63
28	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	6057.63
29	Rodemacher 2	CLECO	LA	558.00	0.02600	100.00%	6615.63
30	River Bend 1	GSU/CAJUN	LA	1022.30	0.02868	100.00%	7637.93
31	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	7674.53
32	Agrielectric	Q.F./GSU	LA	12.50	0.03490	100.00%	7687.03
33	Dolet Hills	CLECO	LA	650.37	0.03540	100.00%	8337.40
34	Roy S. Nelson 6	GSU	LA	430.00	0.04020	100.00%	8767.40
35	Natchitoches	Natchitoches	LA	48.00	0.04021	100.00%	8815.40
36	Welsh 6	SWEPCO	TX	1674.00	0.04190	100.00%	10489.40
37	Southern Companies	GSU,LP&L S	MS	3853.00	0.04331	0.00%	10489.40
38	ERCOT	SWEPCO	TX	600.00	0.04891	0.00%	10489.40
39	Morgan City	Morgan City	LA	65.60	0.05173	100.00%	10555.00
40	Big Cajun 1	CAJUN	LA	230.00	0.05267	100.00%	10785.00
41	Teche	CLECO	LA	427.90	0.05310	100.00%	11212.90
42	Lewis Creek	GSU	TX	544.00	0.05390	100.00%	11756.90
43	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.05404	0.00%	11756.90
44	Sabine	GSU	TX	2051.00	0.05500	100.00%	13807.90
45	Wilkes 5	SWEPCO	TX	881.52	0.05570	100.00%	14689.42
46	Roy S. Nelson 3&4	GSU	LA	755.00	0.05980	22.25%	14857.41
47	Arsenal Hill 1	SWEPCO	LA	125.00	0.06060	100.00%	14982.41
48	Rodemacher 1	CLECO	LA	445.50	0.06210	47.20%	15192.68
49	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.06380	4.67%	15201.65
50	Nine Mile Point	LP&L	LA	1917.00	0.06420	100.00%	17118.65
51	Knox Lee 3	SWEPCO	TX	499.50	0.06650	0.00%	17118.65
52	Little Gypsy	LP&L	LA	1251.00	0.06680	0.00%	17118.65
53	Willow Glen	GSU	LA	2178.00	0.06710	0.00%	17118.65
54	PSOK	SWEPCO	OK	1098.00	0.06927	0.00%	17118.65
55	Michoud	NOPSI	LA	959.00	0.06940	0.00%	17118.65
56	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.06985	0.00%	17118.65
57	Houma	City/Parish	LA	98.00	0.07251	0.00%	17118.65
58	Waterford 1&2	LP&L	LA	891.00	0.07470	0.00%	17118.65
59	Coughlin	CLECO	LA	368.10	0.07850	0.00%	17118.65
60	Sterlington	LP&L	LA	480.00	0.07900	0.00%	17118.65
61	Ruston	Ruston	LA	81.00	0.08193	0.00%	17118.65
62	Lieberman 2	SWEPCO	LA	277.27	0.08610	0.00%	17118.65
63	Lone Star 4	SWEPCO	TX	50.00	0.09590	0.00%	17118.65
64	Hunter*	Alexandria	LA	171.50	0.10800	0.00%	17118.65
65	A.B. Patterson - S	NOPSI	LA	16.00	0.21440	0.00%	17118.65
66	Buras	LP&L	LA	21.00	0.21880	0.00%	17118.65
67	Rayne	Rayne	LA	2.50	0.32934	0.00%	17118.65
68	Plaquemine	LEPA	LA	42.90	0.33913	0.00%	17118.65

APPENDIX E.8 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	New Roads	New Roads	LA	7.60	3.28619	0.00%	17118.65
70	Opelousas	Opelousas	LA	36.00	8.00000	0.00%	17118.65
71	Market Street	NOPSI	LA	103.00	8.00000	0.00%	17118.65
72	A.B. Patterson - G	NOPSI	LA	133.00	8.00000	0.00%	17118.65
73	Thibodaux 9	LP&L	LA	21.00	8.00000	0.00%	17118.65
74	Franklin	CLECO	LA	10.00	8.00000	0.00%	17118.65
75	Monroe	LP&L	LA	137.00	8.00000	0.00%	17118.65
76	Firestone***	Q.F./GSU	LA	0.30	8.00000	0.00%	17118.65
77	Louisiana Station #2	GSU	LA	175.00	8.00000	0.00%	17118.65
78	Neches	GSU	TX	269.00	8.00000	0.00%	17118.65
79	Louisiana Station #1	GSU	LA	148.00	8.00000	0.00%	17118.65
80	LA Station #1 Un.4A	GSU	LA	129.00	8.00000	0.00%	17118.65
81	Citgo***	Q.F./GSU	LA	75.00	8.00000	0.00%	17118.65

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.9
ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #9

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	61.73%	9852.11
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	9874.11
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	9920.11
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	9947.11
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	9957.11
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	10065.11
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	10137.11
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	11811.11
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	11830.26
26	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.02128	64.08%	15031.05
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	15115.85
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	15151.85
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	15151.95
30	ERCOT	SWEPCO	TX	600.00	0.02214	100.00%	15751.95
31	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	16421.95
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	16513.45
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	16570.95
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	16734.95
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	16757.95
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	100.00%	16882.95
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	16883.55
38	PSOK	SWEPCO	OK	1098.00	0.02575	16.37%	17063.30
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	17068.30
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	17612.30
41	Sabine	GSU	TX	2051.00	0.02700	100.00%	19663.30
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	53.48%	20134.73
43	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	20171.33
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	100.00%	20926.33
45	Ruston	Ruston	LA	81.00	0.02962	0.00%	20926.33
46	Rodemacher 1	CLECO	LA	445.50	0.03000	0.00%	20926.33
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	100.00%	22843.33
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	0.00%	22843.33
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	0.00%	22843.33
50	Michoud	NOPSI	LA	959.00	0.03200	60.88%	23427.17
51	Willow Glen	GSU	LA	2178.00	0.03200	0.00%	23427.17
52	Little Gypsy	LP&L	LA	1251.00	0.03200	0.00%	23427.17
53	Teche	CLECO	LA	427.90	0.03210	0.00%	23427.17
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	23427.17
55	Sterlington	LP&L	LA	480.00	0.03300	0.00%	23427.17
56	Coughlin	CLECO	LA	368.10	0.03300	0.00%	23427.17
57	Hunter*	Alexandria	LA	171.50	0.03400	0.00%	23427.17
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	23427.17
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	23427.17
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	23427.17
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	23427.17
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	23427.17
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	23427.17
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	23427.17
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	23427.17
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	23427.17
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	23427.17
68	Buras	LP&L	LA	21.00	0.09000	0.00%	23427.17

APPENDIX E.9 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	23427.17
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	23427.17
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	23427.17
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	23427.17
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	23427.17
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	23427.17
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	23427.17
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	23427.17
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	23427.17
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	23427.17
79	Neches	GSU	TX	269.00	4.00000	0.00%	23427.17
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	23427.17
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	23427.17

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.10

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #10

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	54.47%	9572.38
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	9594.38
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	9640.38
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	9667.38
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	9677.38
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	9785.38
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	9857.38
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	11531.38
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	11550.53
26	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.02128	45.42%	13819.26
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	13904.06
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	13940.06
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	13940.16
30	ERCOT	SWEPCO	TX	600.00	0.02214	100.00%	14540.16
31	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	15210.16
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	15301.66
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	15359.16
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	15523.16
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	15546.16
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	34.44%	15589.21
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	0.00%	15589.21
38	PSOK	SWEPCO	OK	1098.00	0.02575	0.00%	15589.21
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	0.00%	15589.21
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	16133.21
41	Sabine	GSU	TX	2051.00	0.02700	64.02%	17446.26
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	0.00%	17446.26
43	BASF	Q.F./GSU	LA	36.60	0.02870	0.00%	17446.26
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	0.00%	17446.26
45	Ruston	Ruston	LA	81.00	0.02962	0.00%	17446.26
46	Rodemacher 1	CLECO	LA	445.50	0.03000	0.00%	17446.26
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	14.44%	17723.07
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	0.00%	17723.07
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	0.00%	17723.07
50	Michoud	NOPSI	LA	959.00	0.03200	0.00%	17723.07
51	Willow Glen	GSU	LA	2178.00	0.03200	0.00%	17723.07
52	Little Gypsy	LP&L	LA	1251.00	0.03200	0.00%	17723.07
53	Teche	CLECO	LA	427.90	0.03210	0.00%	17723.07
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	17723.07
55	Sterlington	LP&L	LA	480.00	0.03300	0.00%	17723.07
56	Coughlin	CLECO	LA	368.10	0.03300	0.00%	17723.07
57	Hunter*	Alexandria	LA	171.50	0.03400	0.00%	17723.07
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	17723.07
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	17723.07
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	17723.07
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	17723.07
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	17723.07
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	17723.07
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	17723.07
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	17723.07
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	17723.07
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	17723.07
68	Buras	LP&L	LA	21.00	0.09000	0.00%	17723.07

APPENDIX E.10 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	17723.07
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	17723.07
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	17723.07
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	17723.07
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	17723.07
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	17723.07
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	17723.07
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	17723.07
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	17723.07
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	17723.07
79	Neches	GSU	TX	269.00	4.00000	0.00%	17723.07
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	17723.07
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	17723.07

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.11

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #11

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	0.00%	7473.65
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	7495.65
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	7541.65
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	7568.65
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	7578.65
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	7686.65
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	7758.65
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	9432.65
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	9451.80
26	Entergy, Arkansas	LP&L N. SWEPCO	AR	4995.00	0.02128	0.00%	9451.80
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	9536.60
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	9572.60
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	9572.70
30	ERCOT	SWEPCO	TX	600.00	0.02214	0.00%	9572.70
31	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	10242.70
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	10334.20
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	10391.70
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	10555.70
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	10578.70
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	100.00%	10703.70
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	10704.30
38	PSOK	SWEPCO	OK	1098.00	0.02575	0.00%	10704.30
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	10709.30
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	11253.30
41	Sabine	GSU	TX	2051.00	0.02700	100.00%	13304.30
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	100.00%	14185.82
43	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	14222.42
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	100.00%	14977.42
45	Ruston	Ruston	LA	81.00	0.02962	100.00%	15058.42
46	Rodemacher 1	CLECO	LA	445.50	0.03000	100.00%	15503.92
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	100.00%	17420.92
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	100.00%	17650.92
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	100.00%	18150.42
50	Michoud	NOPSI	LA	959.00	0.03200	100.00%	19109.42
51	Willow Glen	GSU	LA	2178.00	0.03200	62.59%	20472.63
52	Little Gypsy	LP&L	LA	1251.00	0.03200	100.00%	21723.63
53	Teche	CLECO	LA	427.90	0.03210	100.00%	22151.53
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	22151.53
55	Sterlington	LP&L	LA	480.00	0.03300	100.00%	22631.53
56	Coughlin	CLECO	LA	368.10	0.03300	0.00%	22631.53
57	Hunter*	Alexandria	LA	171.50	0.03400	0.00%	22631.53
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	22631.53
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	22631.53
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	22631.53
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	22631.53
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	22631.53
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	22631.53
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	22631.53
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	22631.53
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	22631.53
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	22631.53
68	Buras	LP&L	LA	21.00	0.09000	0.00%	22631.53

APPENDIX E.11 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	22631.53
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	22631.53
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	22631.53
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	22631.53
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	22631.53
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	22631.53
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	22631.53
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	22631.53
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	22631.53
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	22631.53
79	Neches	GSU	TX	269.00	4.00000	0.00%	22631.53
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	22631.53
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	22631.53

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.12
ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #12

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2*	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	0.00%	7473.65
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	7495.65
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	7541.65
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	7568.65
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	7578.65
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	7686.65
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	7758.65
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	9432.65
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	9451.80
26	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.02128	0.00%	9451.80
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	9536.60
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	9572.60
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	9572.70
30	ERCOT	SWEPCO	TX	600.00	0.02214	0.00%	9572.70
31	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	10242.70
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	10334.20
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	10391.70
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	10555.70
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	10578.70
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	100.00%	10703.70
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	10704.30
38	PSOK	SWEPCO	OK	1098.00	0.02575	0.00%	10704.30
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	10709.30
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	11253.30
41	Sabine	GSU	TX	2051.00	0.02700	100.00%	13304.30
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	100.00%	14185.82
43	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	14222.42
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	100.00%	14977.42
45	Ruston	Ruston	LA	81.00	0.02962	100.00%	15058.42
46	Rodemacher 1	CLECO	LA	445.50	0.03000	23.14%	15161.51
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	100.00%	17078.51
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	0.00%	17078.51
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	0.00%	17078.51
50	Michoud	NOPSI	LA	959.00	0.03200	7.20%	17147.56
51	Willow Glen	GSU	LA	2178.00	0.03200	0.00%	17147.56
52	Little Gypsy	LP&L	LA	1251.00	0.03200	0.00%	17147.56
53	Teche	CLECO	LA	427.90	0.03210	0.00%	17147.56
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	17147.56
55	Sterlington	LP&L	LA	480.00	0.03300	0.00%	17147.56
56	Coughlin	CLECO	LA	368.10	0.03300	0.00%	17147.56
57	Hunter*	Alexandria	LA	171.50	0.03400	0.00%	17147.56
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	17147.56
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	17147.56
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	17147.56
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	17147.56
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	17147.56
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	17147.56
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	17147.56
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	17147.56
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	17147.56
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	17147.56
68	Buras	LP&L	LA	21.00	0.09000	0.00%	17147.56

APPENDIX E.12 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	17147.56
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	17147.56
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	17147.56
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	17147.56
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	17147.56
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	17147.56
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	17147.56
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	17147.56
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	17147.56
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	17147.56
79	Neches	GSU	TX	269.00	4.00000	0.00%	17147.56
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	17147.56
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	17147.56

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.13

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #13

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	56.51%	9650.98
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	9672.98
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	9718.98
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	9745.98
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	9755.98
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	9863.98
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	9935.98
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	11609.98
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	11629.13
26	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.02128	50.46%	14149.61
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	14234.41
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	14270.41
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	14270.51
30	ERCOT	SWEPCO	TX	600.00	0.02214	100.00%	14870.51
31	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	15540.51
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	15632.01
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	15689.51
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	15853.51
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	15876.51
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	100.00%	16001.51
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	16002.11
38	PSOK	SWEPCO	OK	1098.00	0.02575	0.89%	16011.88
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	16016.88
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	16560.88
41	Sabine	GSU	TX	2051.00	0.02700	100.00%	18611.88
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	78.08%	19300.17
43	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	19336.77
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	100.00%	20091.77
45	Ruston	Ruston	LA	81.00	0.02962	0.00%	20091.77
46	Rodemacher 1	CLECO	LA	445.50	0.03000	0.00%	20091.77
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	100.00%	22008.77
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	0.00%	22008.77
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	0.00%	22008.77
50	Michoud	NOPSI	LA	959.00	0.03200	100.00%	22967.77
51	Willow Glen	GSU	LA	2178.00	0.03200	0.00%	22967.77
52	Little Gypsy	LP&L	LA	1251.00	0.03200	15.88%	23166.43
53	Teche	CLECO	LA	427.90	0.03210	0.00%	23166.43
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	23166.43
55	Sterlington	LP&L	LA	480.00	0.03300	0.00%	23166.43
56	Coughlin	CLECO	LA	368.10	0.03300	0.00%	23166.43
57	Hunter*	Alexandria	LA	171.50	0.03400	0.00%	23166.43
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	23166.43
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	23166.43
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	23166.43
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	23166.43
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	23166.43
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	23166.43
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	23166.43
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	23166.43
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	23166.43
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	23166.43
68	Buras	LP&L	LA	21.00	0.09000	0.00%	23166.43

APPENDIX E.13 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	23166.43
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	23166.43
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	23166.43
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	23166.43
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	23166.43
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	23166.43
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	23166.43
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	23166.43
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	23166.43
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	23166.43
79	Neches	GSU	TX	269.00	4.00000	0.00%	23166.43
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	23166.43
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	23166.43

NOTES:

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2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.14

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #14

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	49.28%	9372.41
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	9394.41
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	9440.41
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	9467.41
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	9477.41
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	9585.41
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	9657.41
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	11331.41
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	11350.56
26	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.02128	29.19%	12808.60
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	12893.40
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	12929.40
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	12929.50
30	ERCOT	SWEPCO	TX	600.00	0.02214	100.00%	13529.50
31	Dow Chemical	O.F./GSU	LA	670.00	0.02220	100.00%	14199.50
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	14291.00
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	14348.50
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	14512.50
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	14535.50
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	100.00%	14660.50
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	0.00%	14660.50
38	PSQK	SWEPCO	OK	1098.00	0.02575	0.00%	14660.50
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	0.00%	14660.50
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	15204.50
41	Sabine	GSU	TX	2051.00	0.02700	76.67%	16777.00
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	0.00%	16777.00
43	BASF	Q.F./GSU	LA	36.60	0.02870	0.00%	16777.00
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	0.00%	16777.00
45	Ruston	Ruston	LA	81.00	0.02962	0.00%	16777.00
46	Rodemacher 1	CLECO	LA	445.50	0.03000	0.00%	16777.00
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	0.00%	16777.00
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	0.00%	16777.00
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	0.00%	16777.00
50	Michoud	NOPSI	LA	959.00	0.03200	74.25%	17489.06
51	Willow Glen	GSU	LA	2178.00	0.03200	0.00%	17489.06
52	Little Gypsy	LP&L	LA	1251.00	0.03200	0.00%	17489.06
53	Teche	CLECO	LA	427.90	0.03210	0.00%	17489.06
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	17489.06
55	Sterlington	LP&L	LA	480.00	0.03300	0.00%	17489.06
56	Coughlin	CLECO	LA	368.10	0.03300	0.00%	17489.06
57	Hunter*	Alexandria	LA	171.50	0.03400	0.00%	17489.06
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	17489.06
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	17489.06
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	17489.06
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	17489.06
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	17489.06
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	17489.06
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	17489.06
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	17489.06
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	17489.06
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	17489.06
68	Buras	LP&L	LA	21.00	0.09000	0.00%	17489.06

APPENDIX E.14 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	17489.06
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	17489.06
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	17489.06
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	17489.06
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	17489.06
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	17489.06
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	17489.06
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	17489.06
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	17489.06
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	17489.06
79	Neches	GSU	TX	269.00	4.00000	0.00%	17489.06
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	17489.06
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	17489.06

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 Dunng 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.15
ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #15

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2*	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	0.00%	7473.65
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	7495.65
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	7541.65
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	7568.65
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	7578.65
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	7686.65
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	7758.65
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	9432.65
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	9451.80
26	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.02128	0.00%	9451.80
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	9536.60
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	9572.60
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	9572.70
30	ERCOT	SWEPCO	TX	600.00	0.02214	0.00%	9572.70
31	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	10242.70
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	10334.20
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	10391.70
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	10555.70
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	10578.70
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	100.00%	10703.70
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	10704.30
38	PSOK	SWEPCO	OK	1098.00	0.02575	0.00%	10704.30
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	10709.30
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	11253.30
41	Sabine	GSU	TX	2051.00	0.02700	100.00%	13304.30
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	100.00%	14185.82
43	BASF	Q.F./GSU	LA	36.60	0.02870	100.00%	14222.42
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	100.00%	14977.42
45	Ruston	Ruston	LA	81.00	0.02962	100.00%	15058.42
46	Rodemacher 1	CLECO	LA	445.50	0.03000	100.00%	15503.92
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	100.00%	17420.92
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	0.00%	17420.92
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	100.00%	17920.42
50	Michoud	NOPSI	LA	959.00	0.03200	100.00%	18879.42
51	Willow Glen	GSU	LA	2178.00	0.03200	62.27%	20235.66
52	Little Gypsy	LP&L	LA	1251.00	0.03200	100.00%	21486.66
53	Teche	CLECO	LA	427.90	0.03210	100.00%	21914.56
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	21914.56
55	Sterlington	LP&L	LA	480.00	0.03300	100.00%	22394.56
56	Coughlin	CLECO	LA	368.10	0.03300	28.86%	22500.79
57	Hunter*	Alexandria	LA	171.50	0.03400	74.57%	22628.68
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	22628.68
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	22628.68
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	22628.68
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	22628.68
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	22628.68
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	22628.68
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	22628.68
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	22628.68
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	22628.68
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	22628.68
68	Buras	LP&L	LA	21.00	0.09000	0.00%	22628.68

APPENDIX E.15 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	22628.68
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	22628.68
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	22628.68
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	22628.68
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	22628.68
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	22628.68
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	22628.68
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	22628.68
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	22628.68
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	22628.68
79	Neches	GSU	TX	269.00	4.00000	0.00%	22628.68
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	22628.68
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	22628.68

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that .s interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX E.16

ECONOMIC DISPATCH RESULTS FOR EXPERIMENT #16

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
1	Sidney A. Murray, Jr.	LP&L	LA	192.00	0.00000	100.00%	192.00
2	Minden	Minden	LA	34.50	0.00333	100.00%	226.50
3	Grand Gulf	System Energy	MS	345.00	0.00510	100.00%	571.50
4	Doc Bonin	LAFA	LA	276.00	0.00576	100.00%	847.50
5	Waterford 3	LP&L	LA	1200.00	0.00600	100.00%	2047.50
6	River Bend 1	GSU/CAJUN	LA	1022.30	0.00674	100.00%	3069.80
7	Pirkey 8	SWEPCO	TX	619.38	0.01100	100.00%	3689.18
8	Fina Oil & Chem.**	Q.F./GSU	TX	37.00	0.01400	100.00%	3726.18
9	Dolet Hills	CLECO	LA	650.37	0.01550	100.00%	4376.55
10	NISCO/RSNelson 1&2**	Q.F./GSU	LA	200.00	0.01570	100.00%	4576.55
11	E.I. Dupont**	Q.F./GSU	TX	85.00	0.01650	100.00%	4661.55
12	Roy S. Nelson 6	GSU	LA	430.00	0.01700	100.00%	5091.55
13	Rodemacher 2	CLECO	LA	558.00	0.01738	100.00%	5649.55
14	Exxon Chemical**	Q.F./GSU	LA	84.00	0.01760	100.00%	5733.55
15	Big Cajun 2	CAJUN/GSU	LA	1735.10	0.01795	100.00%	7468.65
16	Cogen Power	Q.F./GSU	TX	5.00	0.01850	100.00%	7473.65
17	Southern Companies	GSU,LP&L S	MS	3853.00	0.01860	0.00%	7473.65
18	IMC-Agrico	Q.F./LP&L	LA	22.00	0.01900	100.00%	7495.65
19	Formosa Plastics	Q.F./GSU	LA	46.00	0.01910	100.00%	7541.65
20	Calciner Ind.	Q.F./LP&L	LA	27.00	0.01910	100.00%	7568.65
21	Engineered Carbons	Q.F./GSU	TX	10.00	0.01980	100.00%	7578.65
22	Vulcan Chemical	Q.F./GSU	LA	108.00	0.02010	100.00%	7686.65
23	Huntsman Corp.	Q.F./GSU	TX	72.00	0.02030	100.00%	7758.65
24	Welsh 6	SWEPCO	TX	1674.00	0.02100	100.00%	9432.65
25	B.P. Oil	Q.F./LP&L	LA	19.15	0.02120	100.00%	9451.80
26	Entergy, Arkansas	LP&L N, SWEPCO	AR	4995.00	0.02128	0.00%	9451.80
27	Clark Refining	Q.F./GSU	TX	84.80	0.02130	100.00%	9536.60
28	Air Liquide	Q.F./GSU	TX	36.00	0.02140	100.00%	9572.60
29	Jeanerette Sugar*	Q.F./CLECO	LA	0.10	0.02190	100.00%	9572.70
30	ERCOT	SWEPCO	TX	600.00	0.02214	0.00%	9572.70
31	Dow Chemical	Q.F./GSU	LA	670.00	0.02220	100.00%	10242.70
32	Borden Chemical	Q.F./GSU	LA	91.50	0.02240	100.00%	10334.20
33	James River Paper	Q.F./GSU	LA	57.50	0.02240	100.00%	10391.70
34	Star Enterprises	Q.F./GSU	TX	164.00	0.02290	100.00%	10555.70
35	Air Products	Q.F./NOPSI	LA	23.00	0.02370	100.00%	10578.70
36	Arsenal Hill 1	SWEPCO	LA	125.00	0.02500	100.00%	10703.70
37	Dean Lumber*	Q.F./SWEPCO	TX	0.60	0.02570	100.00%	10704.30
38	PSOK	SWEPCO	OK	1098.00	0.02575	0.00%	10704.30
39	Snider Industries*	Q.F./SWEPCO	TX	5.00	0.02590	100.00%	10709.30
40	Lewis Creek	GSU	TX	544.00	0.02600	100.00%	11253.30
41	Sabine	GSU	TX	2051.00	0.02700	100.00%	13304.30
42	Wilkes 5	SWEPCO	TX	881.52	0.02700	100.00%	14185.82
43	BASF	Q.F./GSU	LA	36.60	0.02870	0.00%	14185.82
44	Roy S. Nelson 3&4	GSU	LA	755.00	0.02900	0.00%	14185.82
45	Ruston	Ruston	LA	81.00	0.02962	100.00%	14266.82
46	Rodemacher 1	CLECO	LA	445.50	0.03000	29.38%	14397.71
47	Nine Mile Point	LP&L	LA	1917.00	0.03100	95.14%	16221.54
48	Big Cajun 1	CAJUN	LA	230.00	0.03166	0.00%	16221.54
49	Knox Lee 3	SWEPCO	TX	499.50	0.03200	0.00%	16221.54
50	Michoud	NOPSI	LA	959.00	0.03200	91.98%	17103.63
51	Willow Glen	GSU	LA	2178.00	0.03200	0.00%	17103.63
52	Little Gypsy	LP&L	LA	1251.00	0.03200	0.00%	17103.63
53	Teche	CLECO	LA	427.90	0.03210	0.00%	17103.63
54	Entergy, Mississippi	GSU, LP&L S&N	MS	4079.00	0.03283	0.00%	17103.63
55	Sterlington	LP&L	LA	480.00	0.03300	0.00%	17103.63
56	Coughlin	CLECO	LA	368.10	0.03300	0.00%	17103.63
57	Hunter*	Alexandria	LA	171.50	0.03400	0.00%	17103.63
58	Agrielectric	Q.F./GSU	LA	12.50	0.03490	0.00%	17103.63
59	Waterford 1&2	LP&L	LA	891.00	0.03500	0.00%	17103.63
60	Houma	City/Parish	LA	98.00	0.03869	0.00%	17103.63
61	Lieberman 2	SWEPCO	LA	277.27	0.03900	0.00%	17103.63
62	Natchitoches	Natchitoches	LA	48.00	0.04021	0.00%	17103.63
63	Morgan City	Morgan City	LA	65.60	0.04145	0.00%	17103.63
64	Lone Star 4	SWEPCO	TX	50.00	0.04200	0.00%	17103.63
65	New Roads	New Roads	LA	7.60	0.04918	0.00%	17103.63
66	Rayne	Rayne	LA	2.50	0.06517	0.00%	17103.63
67	Plaquemine	LEPA	LA	42.90	0.07953	0.00%	17103.63
68	Buras	LP&L	LA	21.00	0.09000	0.00%	17103.63

APPENDIX E.16 (Continued)

PLANT #	PLANT NAME	Q.F./HOST	ST.	MW CAPACITY	AVERAGE VAR. COST	PERCENT DISPATCH	CUMMULATIVE CAPACITY
69	A.B. Patterson - S	NOPSI	LA	16.00	0.10700	0.00%	17103.63
70	Franklin	CLECO	LA	10.00	4.00000	0.00%	17103.63
71	Opelousas	Opelousas	LA	36.00	4.00000	0.00%	17103.63
72	A.B. Patterson - G	NOPSI	LA	133.00	4.00000	0.00%	17103.63
73	Monroe	LP&L	LA	137.00	4.00000	0.00%	17103.63
74	Market Street	NOPSI	LA	103.00	4.00000	0.00%	17103.63
75	Thibodaux 9	LP&L	LA	21.00	4.00000	0.00%	17103.63
76	Citgo***	Q.F./GSU	LA	75.00	4.00000	0.00%	17103.63
77	Firestone***	Q.F./GSU	LA	0.30	4.00000	0.00%	17103.63
78	Louisiana Station #2	GSU	LA	175.00	4.00000	0.00%	17103.63
79	Neches	GSU	TX	269.00	4.00000	0.00%	17103.63
80	Louisiana Station #1	GSU	LA	148.00	4.00000	0.00%	17103.63
81	LA Station #1 Un.4A	GSU	LA	129.00	4.00000	0.00%	17103.63

NOTES:

1 * Indicates 1994 data, otherwise all unmarked data is 1996 data.
2 ** Indicates 1995 data, otherwise all unmarked data is 1996 data.
3 *** Indicates a Q.F. that is interconnected to a HOST's system but is not selling back power.
4 During 1996, capacity for Lafayette Utilities' Doc Bonin facility was 276 MW. Unit #1 (50 MW) was down for repairs. Normal capacity from the facility is 326 MW.
5 A "4" for O&M COST or FUEL COST indicates a unit that is off-line. (i.e. a mothballed or unavailable unit)

APPENDIX F

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY

APPENDIX F.1

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #1 AND #9

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$674,480,323	$685,691,683
CLECO	$113,627,608	$157,936,581
SWEPCO	$ 24,558,310	$ 33,108,181
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$812,666,241**	**$876,736,445**

APPENDIX F.2

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #2 AND #10

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,032,173,589	$1,106,864,568
CLECO	$ 113,627,608	$ 157,936,581
SWEPCO	$ 40,936,398	$ 46,332,019
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$1,186,737,595**	**$1,311,133,168**

APPENDIX F.3

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #3 AND #11

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$329,902,580	$319,003,753
CLECO	$ 45,923,607	$ 45,923,607
SWEPCO	$ 9,887,906	$ 9,887,906
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$385,714,093**	**$374,815,266**

APPENDIX F.4

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #4 AND #12

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$795,727,988	$746,197,262
CLECO	$113,627,608	$142,269,875
SWEPCO	$ 24,249,509	$ 24,249,509
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$933,605,105**	**$912,716,646**

APPENDIX F.5

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #5 AND #13

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$642,179,697	$622,642,023
CLECO	$113,627,608	$157,936,581
SWEPCO	$ 24,675,154	$ 28,423,672
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$780,482,459**	**$809,002,276**

APPENDIX F.6

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #6 AND #14

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,023,522,418	$1,029,991,734
CLECO	$ 113,627,608	$ 157,936,581
SWEPCO	$ 39,312,054	$ 43,292,226
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$1,176,462,080**	**$1,231,220,541**

APPENDIX F.7

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #7 AND #15

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$323,369,709	$319,686,448
CLECO	$ 45,923,607	$ 33,055,645
SWEPCO	$ 9,887,906	$ 9,887,906
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$379,181,222**	**$362,629,999**

APPENDIX F.8

COST-OF-PLANT METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #8 AND #16

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$819,813,856	$745,924,646
CLECO	$ 81,671,320	$138,045,146
SWEPCO	$ 24,249,509	$ 24,249,509
Sys. Energy Resources	$ 0	$ 0
TOTALS	**$925,734,685**	**$908,219,301**

APPENDIX G

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY

APPENDIX G.1

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #1 AND #9

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,807,375,732	$3,926,602,067
CLECO	$ 113,627,608	$ 463,221,872
SWEPCO	$ 24,558,311	$ 375,144,574
Sys. Energy Resources	$ 379,918,684	$ 703,080,260
TOTALS	**$2,325,480,335**	**$5,468,048,773**

APPENDIX G.2

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #2 AND #10

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,990,843,661	$3,972,431,704
CLECO	$ 113,627,608	$ 475,026,599
SWEPCO	$ 40,936,398	$ 381,695,233
Sys. Energy Resources	$ 424,186,763	$ 707,671,486
TOTALS	**$2,569,594,430**	**$5,536,825,022**

APPENDIX G.3

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #3 AND #11

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,458,900,741	$3,883,590,280
CLECO	$ 94,980,764	$ 446,277,801
SWEPCO	$ 25,365,713	$ 369,976,280
Sys. Energy Resources	$ 329,075,576	$ 698,088,391
TOTALS	**$1,908,322,794**	**$5,397,932,752**

APPENDIX G.4

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #4 AND #12

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,942,575,392	$3,935,180,469
CLECO	$ 113,627,608	$ 461,030,159
SWEPCO	$ 28,886,167	$ 375,949,824
Sys. Energy Resources	$ 424,186,763	$ 703,080,260
TOTALS	**$2,509,275,930**	**$5,475,240,712**

APPENDIX G.5

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #5 AND #13

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,802,043,988	$3,926,727,463
CLECO	$ 113,627,608	$ 463,221,872
SWEPCO	$ 24,675,154	$ 375,949,824
Sys. Energy Resources	$ 379,918,684	$ 705,728,783
TOTALS	**$2,320,265,434**	**$5,471,627,942**

APPENDIX G.6

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #6 AND #14

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,998,916,643	$3,940,817,694
CLECO	$ 113,627,608	$ 463,221,872
SWEPCO	$ 39,312,054	$ 375,949,824
Sys. Energy Resources	$ 424,186,763	$ 703,080,260
TOTALS	**$2,576,043,068**	**$5,483,069,650**

APPENDIX G.7

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #7 AND #15

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$ 866,330,976	$3,850,324,554
CLECO	$ 45,923,607	$ 429,763,051
SWEPCO	$ 14,524,565	$ 363,214,522
Sys. Energy Resources	$ 57,488,910	$ 693,542,309
TOTALS	**$ 984,268,058**	**$5,336,844,436**

APPENDIX G.8

EMBEDDED COST METHOD FOR ESTIMATING STRANDED GENERATION FACILITY COSTS SEPARATED BY COMPANY FOR EXPERIMENTS #8 AND #16

COMPANY	AVERAGE VARIABLE COST DISPATCHING	FUEL COST DISPATCHING
Entergy	$1,972,652,876	$3,935,922,265
CLECO	$ 81,671,320	$ 460,655,702
SWEPCO	$ 28,886,168	$ 375,949,824
Sys. Energy Resources	$ 424,186,763	$ 703,080,260
TOTALS	**$2,507,397,127**	**$5,475,608,051**

VITA

Robert Frank Cope, III, was born on August 10, 1963, in New Orleans, Louisiana. Dr. Cope holds a bachelor of science degree in Electrical Engineering (December 1986) and a master of business administration degree (May 1991) from Louisiana State University. He is also a registered Professional (Electrical) Engineer with the State Boards for Professional Engineers in Texas and Louisiana.

Upon completion of his undergraduate degree, he was employed as a Field Service Engineer with the General Electric Company from January 1987 to August 1989. He then returned to Louisiana State University to pursue a master of business administration degree. Upon completion of the master's degree, he held positions of Engineer, Senior Engineer, and Underground Zone Technical Engineer at Houston Lighting & Power Company from June 1991 to August 1994. He again returned to Louisiana State University in August of 1994 to pursue a doctorate in Business Administration with a major in Information Systems and Decision Sciences. In December of 1998 he was awarded the degree of Doctor of Philosophy. While completing his research, Dr. Cope also served as a Research Associate at Louisiana State University's Center for Energy Studies. Since August of 1998, he has held the position of Assistant Professor at Southeastern Louisiana University.

DOCTORAL EXAMINATION AND DISSERTATION REPORT

Candidate: Robert Frank Cope, III

Major Field: Business Administration
(Information Systems and Decision Sciences)

Title of Dissertation: A Methodology to Identify Stranded Generation Facilities and Estimate Stranded Costs for Louisiana's Electric Utility Industry

Approved:

Dan B Rinks

Major Professor and Chairman

Dean of the Graduate School

EXAMINING COMMITTEE:

David E Desmarteau

Date of Examination:

July 13, 1998

IMAGE EVALUATION TEST TARGET (QA-3)

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6"

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