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Fuel, environmental, and transmission pricing considerations in a deregulated environment

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Fuel, environmental, and transmission pricing considerations in a deregulated environment

by

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This is to certify that the Doctoral dissertation of

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has met the dissertation requirements of Iowa State University

Signature was redacted for privacy.

Major Professor

Signature was redacted for privacy.

For the Major Program

Signature was redacted for privacy.

For the Graduate College

Μνημη

Βλασιου Γ. Ομπεση

Ολα χανονται.

Του καθενος

ερχεται η ωρα.

Ολα μενουν.

Εγω φευγω.

Εσεις να δουμε τωρα.

(Ο. Ελυτης, Ημερολογιο ενος αθεατου Απριλιου)

Memory

Vlassis G. Obessis

Everything vanishes.

Everybody's time

comes.

Everything stays.

I go.

Let's see you now.

(O. Elytis, Diary of an invisible April)

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NOMENCLATURE

Symbols used:

B: number of fuel blocks

C: fuel cost

E: emissions (in general)

e: emission coefficient

F: fuel use

f: fuel consumption coefficients

G: number of generating units in the system

H: number of time interval (hours) in entire simulation horizon

K: number of fuel contracts utilized

L: Lagrangian function

N: nitrogen oxides emissions

n: nitrogen oxides emission coefficient

O: set of fuel groups being constrained

P: power output

S: sulfur dioxide emissions

s: sulfur dioxide emission coefficient

U: unit fuel price

V: amount of fuel supplied

W: cumulative system fuel needs

Z: function of

α: weighting factor

Δ: game payoff distribution (or allocation)

Φ: characteristic function of a game

Γ: coalition of players

Π: set of players

π: numbers of players in a game

Ξ: Shapley value

Indices used:

i: generating unit index

j: time period index

k: fuel contract index

m: fuel block index

p: plant index

ϑ: fuel group index

ρ: player index

Superscripts used:

Mn: minimum value (or limit)

Mx: maximum value (or limit)

R: load (power received) requirement

[1,..,4]: type of emission constraint

Subscripts used:

a:	constant/first coefficient
b:	linear/second coefficient
d:	cubic/fourth coefficient
A:	total power system (area)
T:	total analysis period

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1. INTRODUCTION

1.1 The Overall Problem

Responding to criticism claiming that the regulation of the power industry has been largely ineffective, the federal and many state governments have passed several pieces of legislation in the last few years that significantly affect power producers and their operations. A direct result of the utility deregulation – or according to some, regulation restructuring – is the decline of the traditional concept of the vertically integrated utility. Deregulation has also changed the utility industry operational framework. Existing short term scheduling processes need to undergo modifications in order to include the features and complexities associated with the reality of the restructured regulatory environment.

Since the primary reason for the regulation of electric utilities was their being considered as "natural monopolies", it is expected that increased competition will eliminate many of the inefficiencies associated with governmental protectionism. To boost competition, the National Energy Policy Act (NEPA) was signed into law in 1992. One of the objectives of NEPA was the development of electricity markets operating according to the economic principles of free trade and competition. In such markets, electricity is being treated as a commodity and is being bought, sold, or traded subject to market signals rather than regulatory provisions. The first such markets have already been established. To survive in a competitive market, utilities have to actively explore their options of reducing costs and increasing efficiency. Further, NEPA provided for mandatory wholesale power wheeling. Several states also have announced plans for mandatory retail wheeling in the near future. Therefore, transmission services are subject to increased competitive forces as well. Several brokerage-type systems have been proposed to model the organization structure that will serve as the marketplace for electricity. However, final decisions are not complete made and the restructuring of the industry is far from finished.

Traditionally, utilities have been subject to tight environmental regulations. In response to increasing public concerns about the continuous environmental degradation, Congress has also enacted several pieces of legislation intended to limit emissions. The 1990 Clean Air Act Amendments (CAAA) is an important bill for it no longer adopts the traditional command-and-control approach. Instead, although tightening the federal air pollution standards, it offers utilities considerably increased flexibility in choosing their compliance strategies. Market concepts were introduced by providing for emission allowances and the associated markets.

Therefore, the electric power industry is in a major restructuring phase. There is a shift from a cost-based to a market- and price-based approach. In the past, prices were set applying a guaranteed rate of return on an all-inclusive rate base. The rate base was calculated based on the anticipated cost of production but it did sometimes include unnecessary expenditures. However, this in no longer the case. In today's environment, prices depend on market conditions and obey the fundamental principles of supply and demand. Existing markets have been opened to free competition and trading. New markets are being established. The currently available models and corresponding software do not suffice to accurately represent the new environment. New or enhanced approaches and techniques are needed to address the fresh challenges and problems associated with the deregulated reality.

1.2 Justification and Scope of this Work

1.2.1 Fuel and Emission Scheduling

In this new era of competitive electricity markets, the participants need to analyze various possible ways of reducing costs and increasing efficiency. Since fuel costs account for a large portion of total operating costs, power producers need to become even more active in their fuel supply market participation. Fuel markets are becoming more competitive, thus offering power producers additional opportunities for less costly fuel supply purchases. The competitive new environment needs to be incorporated into daily scheduling activities. One alternative could be by means of more accurate fuel supply models that include supply costs and storage constraints. Such costs and constraints need to be accounted for in daily scheduling models and the corresponding software.

Power companies have many options to achieve compliance with the new emissions limitations. Enhanced dispatching techniques are one such option. Just like their fuel supply counterparts, environmental constraints need to be incorporated in the generation scheduling algorithms for on-line short-term dispatching, as well as long-term planning. It is also vital for companies to investigate whether participation in the emission allowances market would provide additional compliance alternatives.

In most previous approaches, fuel and environmental limitations were in general considered as separate sets of constraints. However, emission output is dependent on fuel type, characteristics, and consumption. A complete dispatch algorithm should model such dependence by including accurate representations for both emission and fuel, as well as their interface. Utilities must track actual operations compared to forecasted operations and make appropriate changes resulting from enforcement of both fuel and emission limits.

1.2.2 Transmission Cost Allocation

Several different methodologies for dealing with transmission pricing have been proposed in the relevant literature. To date, much discussion has occurred and no single approach has been universally accepted. Since the transmission grid is simultaneously utilized by several entities, how to fairly allocate the capital, operating, and maintenance costs to the individual users is a timely concern of the power industry. Although this problem is not directly associated with the scheduling problem discussed in the previous section, its significance to the power companies is recognized and it is thus included in this document. The work on the issue presented herein was initially developed during a summer internship and was further expanded during the author's graduate course of study.

1.3 Importance of this Work

The work during this research project focuses primarily on creating a single fuel scheduling and emission scheduling algorithm. This algorithm dispatches generation subject to a combined set of fuel and environmental constraints. Similar projects were addressed only in very few papers, mostly in the context of resource allocation, using simplistic models. Generation costs for power producing companies are in the order of tens of billions of dollars. The models developed in this project thus, should be of importance to the power industry, since even a small fractional decrease in costs resulting from a more efficient generation allocation, might provide significant savings.

The issue of combining multiple sets of constraints into a single automated dispatching algorithm should receive additional attention in light of the current power industry reregulation movement as well as of approaching the year 2000 when the second phase of the emission limiting provisions of the 1990 Clean Air Act Amendments takes effect. A recent Department of Energy report states: "With increasing competition and with phase II of the CAAA90 slated for implementation on January 1, 2000, utilities are showing less interest in making capital investments in expensive pollution control equipment, are uncertain about cost recovery, and want to be more competitive [1]." Most utilities have postponed their pollution abating strategies until later in this decade. Although scrubbers have proved to be a very efficient means of sulfur removal, that efficiency comes at a very high cost, which utilities are reluctant to spend given the current uncertainty of the utility environment. It is expected that power producing companies will employ many alternative strategies, including modified dispatching approaches and active involvement in the emission allowance markets, to complement and fine tune their compliance strategies.

On the other hand, moving rapidly into a more competitive environment, companies will need to explore all possible ways of reducing their costs. They will be aggressive in their fuel marketing strategies and they will more fully explore fuel spot market opportunities. In the event of multiple available fuel supplies, utilities should no longer depend on arbitrary factors to select their fuel suppliers.

Fuel supplies and resultant emission outputs are interdependent variables. More so, in the case of sulfur dioxide (SO_2), and less so in the case of nitrogen oxides (NO_X). Any approach that improves the scheduling process accounting for a large set of fuel supply and emission constraints should benefit the power companies. To the best of the author's knowledge, the suggested approach is probably one of the very few that treats the combined fuel and emission problem giving equal weight to each of the two constraining subproblems. In most scheduling solution approaches described in the relevant literature, only one of the two subproblems is fully addressed, while the other is, at best, only partially addressed.

1.4 Organization of this Dissertation

This work addresses the issues discussed in the previous sections and proposes possible solution techniques. Chapter 2 gives some basic background information on the ongoing regulatory reform of the electric power industry. Chapter 3 focuses on the fuel supply constrained dispatch problem – henceforth referred to more freely as the fuel-constrained dispatch problem – and presents an enhanced scheduling algorithm that accounts for multiple available fuel contracts and their associated limits. Chapter 4 deals with the emission-constrained dispatching and presents a multilevel solution algorithm that can include a variety of emission constraints. Chapter 5 interfaces the two problems and presents a combined algorithm. A series of tests were run and extensive numerical results are presented. In Chapter 6, the transmission cost allocation problem is addressed. A cooperative game theoretic model was evaluated as a potential solution approach. Finally, in Chapter 7, this work is summarized and general conclusions are presented together with suggestions for future work that may expand the ideas and algorithms presented herein.

2. REGULATORY REFORM IN THE POWER INDUSTRY

This chapter provides an update on the ongoing restructuring of the electric power industry as well as background information on the fuel and environmental regulation of electric power producers. Most of the information and the data presented in this chapter are from various U.S. Department of Energy publications. The first section discusses some of the inefficiencies associated with the regulatory environment of the past. The second section presents the current status of regulatory reform in the power industry. The third section provides information on the competition in fuel markets and the fourth section discusses the most frequently adopted fuel procurement practices. Section 2.5 presents background information regarding the environmental regulation of power producers, section 2.6 discusses the particular pollution problems associated with fossil power plants, and section 2.7 outlines the 1990 Clean Air Act Amendments. Subsequently, section 2.8 discusses the interdependence between fuel and emission regulation and the final section of the chapter addresses the environmental impact of open tranmission access.

2.1 Regulation Inefficiencies

The principles that originally dictated the regulation of the electric power industry have come under much discussion and criticism. Past experience clearly has shown that the combination of imperfect regulation and the monopolistic status of the electric utilities led to deviations from what was originally thought to be ideal utility performance. One of the primary issues that has given rise to the questions and concerns about the efficiency of regulation, resulted from the work of H. Averch and L. L. Johnson who investigated possible inefficiencies associated with the rate-of-return type of regulation [2].

2.1.1 The Averch-Johnson Thesis

Harvey Averch and Leland L. Johnson presented their paper, discussing the behavior of a regulated firm, in 1962 [3]. Although they considered a phone company as an example of a regulated firm, their results are applicable to every regulated industry. In their paper, Averch and Johnson considered a monopolistic firm, producing a single, homogeneous product. They concluded that a regulated, profit maximizing company does not exhibit the same performance as the cost minimizing company. *For any given output level, the regulated firm tends to invest more capital and less labor than the cost minimizing firm.* This overcapitalization effect is known as A-J thesis (or A-J effect). In a different phrasing, each regulated firm may use inefficient capital to labor ratios. Assumptions included in this model are: 1) the firm can decide on any price-output combination as long as the regulatory constraint, as defined by Averch and Johnson, is satisfied, ii) no regulatory lag is present, iii) the market cost of capital is constant, and iv) the allowable rate of return exceeds the cost of capital.

Although the overcapitalization proposition is the most important result, the authors arrived at another important conclusion. They claimed that the regulated firm seems to have an incentive to enter competitive markets even when revenues fall below incremental costs. The loss is compensated by price increases on its monopolistic services. This, the cross subsidization clause, although comparatively neglected in the subsequent literature, leads to another important issue; the notorious gold plating or rate base padding.

The Averch-Johnson effect implies social and economic inefficiency. The original work and conclusions found many supporters and many opponents. Empirical data was presented that supported arguments from both sides of the debate. The initial model was expanded, modified and thoroughly analyzed by many economists and policy makers. Many of the original assumptions were heavily criticized. Alternative derivations and propositions have been suggested. Nevertheless, Averch and Johnson's work is still well respected and accepted as a valid representation of the economic behavior of a regulated industry.

2.1.2 Gold Plating

Simply stated, gold plating is the phenomenon of a regulated firm constantly adding nonproductive capital to its rate base. Gold plating (or base padding) charges may be of the following types: i) simple gold plating (such as using unnecessarily expensive equipment, acquiring useless assets, etc.), ii) maintain excessive spare capacity, and iii) penetration in secondary, subsidiary markets at nonprofitable prices (cross subsidization) [4]. Gold plating is an even more blatant inefficiency when compared to simple use of inappropriate capital to labor ratios. It should be noted that under strong regulation, where regulators not only control revenues but eliminate possible nonproductive capital waste as well, gold plating cannot occur.

2.2 Electric Power Industry Restructuring [5]

In the recent past, many of the entities involved in the production, delivery, and utilization of electric power have been somewhat dissatisfied with the existing operational environment. Large industrial customers for years have voiced their desire to freely choose their electrical suppliers and negotiate their own electricity contracts. Independent power producers (IPPs) have been opting for competition in hopes of increased profits. Regulatory bodies have been trying to alleviate concerns that the traditional forms of regulation did not provide maximum efficiency. And finally, utilities were concerned that legislation has severely limited their strategies while, at the same time, offering competitive advantages to their non-utility rivals including independent power producers.

As a result, the electric power industry is currently undergoing a major restructuring that is transforming it into a competitive market. It is expected that, at least functionally, the industry will be further segmented into the three basic components: generation, transmission, and distribution. Most of the ongoing changes are the industry's reaction to Orders 888 and 889 issued by the Federal Energy Regulatory Commission (FERC) on April 24, 1996.

Order 888 deals with the issues regarding open access of the transmission grid and the recovery of stranded costs. These costs are defined as previously incurred costs encumbered by the utilities in their anticipated efforts under the previous regulatory structure to serve their customers for the foreseeable future. These costs can not be fully recovered if customers are completely free to choose their electricity suppliers, as is the case in a fully competitive market. A major concern is which entities should ultimately pay for such costs. A recent study has estimated stranded costs at $88 billion and other projections estimate them anywhere between $20 and $500 billion. FERC, in its Order 888, provides for the recovery of stranded costs since they are vital for utilities to successfully compete in a free market. Departing wholesale customers will be the primary source for the recovery of stranded costs although alternative strategies are still under consideration.

Order 889 requires utilities to install and operate systems for information sharing regarding their available transmission capacities. In addition, more than

88% of the U.S. regulatory agencies are already considering activities related to retail competition. Several states with high electric rates are planning on opening their retail electricity markets to free competition in expectations of lower rates.

In a competitive market, it is critical for utilities to lower their costs. Investor-owned utilities (IOUs) are lowering their O&M costs by changing their fuel purchasing strategies and by reducing the number of their employees. Some IOUs have expanded their business with ventures in additional markets, such as consulting and construction services, oil and gas exploration, generation outside their service areas, foreign utility operation, as well as telecommunications. Furthermore, IOUs are trying to become more competitive through mergers. In 1995, 13 utilities have merged or had a merger decision pending. Unfortunately, not all mergers resulted in reduced costs. At the same time, publicly-owned utilities are also trying to improve their competitiveness by reducing their operating costs. Some of them have announced merger plans while others have significantly reduced their staff and others are considering similar cost cutting procedures. Still others are considering selling their entire operation.

New players will eventually participate, once a competitive market is established. Power marketers are independent companies that buy and sell electric power and transmission services to and from electric utilities. Although the volume of their transactions is currently small, power marketers are expected to play a significant role in the future. Load aggregation is expected to become a significant new business. Spot markets are being formed and electricity futures contracts have already been traded. The independent system operator is emerging as a key player in the operation of the power transmission system of the future. It is an entity vested with the authority to manage the transmission system and it is considered by many as a critical component in creating a sustainable competitive electricity market free from the inefficiencies associated with previous regulatory practices.

The restructuring stage is ongoing and details of the final outcome are still unknown. However, it is certain that the utility industry of the future will be significantly different from that of yesterday and today.

2.3 Regulation and Competition in Fuel Markets

Because of their interdependence at the national and international levels, energy markets overall, are subject to sharp, sudden movements resulting from externalities, such as political instabilities, regional conflicts, etc. Historically, many bills have been enacted to regulate energy markets, and fuel markets more specifically [6]. However, government protectionism has been accused of being inefficient, creating unnecessary costs, and not allowing fuel and energy markets to reach the optimal equilibrium levels that would have been attained had the markets been unrestricted.

Fuel prices started being regulated as early as the 1950's but it was in the 1970's when government intervention reached its peak. As a response to the colluding tactics of OPEC, the U.S. government subsidized energy imports. Later, when oil price controls weakened, oil imports declined. Table 2.1 shows U.S. energy net imports by source for the last two decades [7]. Clearly, the oil price control program of the 1970's resulted in increasing oil imports. In contrast, regulatory schemes in previous decades resulted in decreasing oil imports.

Another criticism against the traditional forms of regulation concerns the lag between requests for rate changes and actual commission decisions. In an attempt to reduce such lags, regulators applied automatic fuel adjustment clauses (FAC). According to a 1974 study, most electricity rate increases were a

Table 2.1 U.S. Net Imports by Source (Quadrillion Btu)

Time	Coal	Natural Gas	Crude Oil[1]	Petroleum[2]	Electricity	Coal Coke	Total
1976	-1.567	0.922	11.221	3.982	0.089	0.000	14.648
1977	-1.401	0.981	13.921	4.321	0.182	0.015	18.019
1978	-1.004	0.941	13.125	3.932	0.204	0.125	17.323
1979	-1.702	1.243	13.328	3.603	0.211	0.063	16.746
1980	-2.391	0.957	10.586	2.912	0.217	-0.035	12.247
1981	-2.918	0.857	8.854	2.522	0.347	-0.016	9.646
1982	-2.768	0.898	6.917	2.128	0.306	-0.022	7.460
1983	-2.013	0.885	6.731	2.351	0.372	-0.016	8.310
1984	-2.119	0.792	6.918	2.970	0.414	-0.011	8.963
1985	-2.389	0.896	6.381	2.570	0.428	-0.013	7.872
1986	-2.193	0.686	8.676	2.855	0.375	-0.017	10.382
1987	-2.049	0.937	9.748	2.784	0.483	0.009	11.911
1988	-2.446	1.221	10.698	3.308	0.328	0.040	13.149
1989	-2.566	1.278	12.296	3.029	0.113	0.030	14.181
1990	-2.705	1.464	12.536	2.757	0.020	0.005	14.077
1991	-2.769	1.666	12.308	1.912	0.231	0.009	13.357
1992	-2.587	1.941	13.065	1.895	0.292	0.027	14.633
1993	-1.780	2.255	14.542	1.854	0.292	0.017	17.180
1994	-1.689	2.518	15.131	2.128	0.459	0.024	18.570
1995	-2.140	2.745	15.432	1.437	0.381	0.026	17.880

[1] crude oil, lease condensate, and crude oil imports for Strategic Petroleum Reserve
[2] petroleum products, unfinished oils, and gasoline blending components

result from FAC being applied rather than actual regulatory decisions [6]. This type of clause promoted inefficiency and rate base gold plating.

Besides directly controlling relative fuel prices, the federal government, in several instances, has directly controlled the fuel choices of power companies. In 1978, the Public Utility Regulatory Policy Act (PURPA) and the Power Plant and Fuel Use Act (PIFUA) required substitution of coal for petroleum in electricity generation, reversing the policy guidelines of previous years [8]. However, despite the potential theoretical advantages of fuel shifting, actual fuel conversion proved to be much more difficult. In many instances, technological considerations became prohibitive and many plants did not successfully complete their fuel shifting programs.

Competition has always existed to some extent in fuel markets. The most fierce intrafuel rivalry has been between coal and oil, especially on the East Coast. The basic factors in choosing one over the other were proximity to mining sites and environmental regulations. Generally speaking, coal has always been the major fuel source for electric utilities. Table 2.2 shows net generation of electricity as a function of fuel type for the last two decades [7]. Despite its popularity, coal is probably the least flexible of all fossil fuels. It's more difficult to extract, process, and transport than natural gas and oil. Moreover, coal boilers are generally larger so that they can handle the more difficult combustion process of coal. Sulfur content is an additional major concern. In order for coal to be offered at competitive prices, economies of scale must be exercised. To offset higher usage costs, mining, transportation, and processing costs must be kept to a minimum. At times, nuclear power seemed to be a significant competitor to coal. However, no new nuclear plants have been ordered since 1978, reflecting the public's and financial organizations' increasing concerns about financial stability, safety, and waste disposal. Natural gas is another fossil fuel competitor with the

Table 2.2 Electric Utility Net Generation of Electricity (Billion KWh)

Time	Coal	Natural Gas[1]	Petroleum[2]	Nuclear	Hydro	Other[3]	Total
1976	944.4	294.6	320.0	191.1	283.7	3.9	2037.7
1977	985.2	305.5	358.2	250.9	220.5	4.0	2124.3
1978	975.7	305.4	365.1	276.4	280.4	3.3	2206.3
1979	1075.0	329.5	303.6	255.2	279.8	4.4	2247.3
1980	1161.6	346.2	246.0	251.1	276.0	5.5	2286.4
1981	1203.2	345.8	206.4	272.7	260.7	6.0	2294.8
1982	1192.0	305.3	146.8	282.8	309.2	5.2	2241.2
1983	1259.4	274.1	144.5	293.7	332.1	6.5	2310.3
1984	1341.7	297.4	119.8	327.6	321.2	8.6	2416.3
1985	1402.1	291.9	100.2	383.7	281.1	10.7	2469.8
1986	1385.8	248.6	136.6	414.0	290.8	11.5	2487.3
1987	1463.8	272.6	118.5	455.3	249.7	12.3	2572.1
1988	1540.7	252.8	148.9	527.0	222.3	12.0	2704.2
1989	1553.7	266.6	158.3	529.4	265.1	11.3	2784.3
1990	1559.6	264.1	117.0	576.9	279.9	10.7	2808.2
1991	1551.2	264.2	111.5	612.6	275.6	10.1	2825.0
1992	1575.9	263.9	88.9	618.8	239.6	10.2	2797.2
1993	1639.2	258.9	99.6	610.3	265.1	9.6	2882.6
1994	1635.5	291.1	91.0	640.4	243.7	8.9	2910.7
1995	1652.9	307.3	60.9	673.4	293.7	6.4	2994.6

[1] supplemental gaseous fuel included
[2] includes fuel oils 1, 2, 4, 5, and 6, crude oil, kerosene, and petroleum coke
[3] includes biomass fuels, wind, geothermal, photovoltaic, and solar thermal

advantage of minimum emissions. However, the Energy Supply Act of 1975 and the Fuel Use Act of 1979 significantly reduced the amount of natural gas available since they encouraged utilities to substitute coal for gas [6].

Overall, fuel markets, despite heavy governmental intervention that at times significantly distorted relative fuel prices, have always been exposed to competitive forces. According to the Department of Energy's forecasts, the use of coal as a fuel for electric utilities will steadily increase and use of nuclear power will continue to decline. Table 2.3 presents quantities used and average costs of fossil fuel receipts at steam electric plants [7].

2.4 Fuel Procurement Practices

Whatever the fuel of choice, electricity producers historically have relied heavily on long-term contracts to secure their fuel supplies. The first fuel contracts were signed near the beginning of the century, whereas oil contracts became popular much later. Gas contracts became very popular during times of perceived energy crises.

Procurement methods may be divided in four broad categories [9]:

i) long-term contracts (ten or more years)

ii) short-term contracts (one to ten years)

iii) very short-term purchases – spot market (less than a year)

iv) captive fuel production, particularly coal.

Typical contracts usually contain provisions regarding

i) quantities of fuel purchased and quality specifications

ii) pricing rules

iii) guarantees

iv) necessary conditions required to modify contract provisions.

Table 2.3 Quantity and Cost of Fossil Fuel Receipts at Steam Electric Utility Plants

Time	Coal		Petroleum[1]		Natural Gas[2]	
	Quantity (Ktons)	Cost (¢/MBtu)	Quantity (Kbarrels)	Cost (¢/MBtu)	Quantity (Mft^3)	Cost (¢/MBtu)
1976	454,858	84.8	549,973	199.0	2,962,811	103.4
1977	490,415	94.7	635,556	224.9	3,106,403	129.1
1978	476,169	111.6	616,040	219.1	3,140,654	142.2
1979	556,558	122.4	515,695	307.2	3,368,976	174.9
1980	593,995	135.1	419,140	435.1	3,588,814	219.9
1981	579,374	153.2	345,544	542.5	3,573,558	280.5
1982	601,427	164.7	239,111	492.2	3,161,348	337.6
1983	592,728	165.6	219,652	462.8	2,732,248	347.4
1984	684,111	166.4	202,372	486.3	2,878,808	360.3
1985	666,743	164.8	164,947	431.7	2,808,921	344.4
1986	686,964	157.9	228,522	243.9	2,387,622	235.1
1987	721,298	150.6	194,578	301.1	2,605,191	224.0
1988	727,775	146.6	236,924	243.9	2,362,721	226.3
1989	753,217	144.5	246,422	289.3	2,472,506	235.5
1990	786,627	145.5	209,350	338.4	2,490,979	232.1
1991	769,923	144.7	169,625	254.8	2,630,818	215.3
1992	775,963	141.2	144,390	255.1	2,637,678	232.8
1993	769,152	138.5	147,902	243.3	2,574,523	256.0
1994	831,929	135.5	142,940	248.8	2,863,904	223.0
1995	826,860	131.8	84,292	267.9	3,023,327	198.4

[1] weighted averages; include fuel oils 1, 2 (light), 4, 5, 6 (heavy), kerosene, jet fuel; does not include petroleum coke

[2] includes supplemental gaseous fuels

Basic pricing rules used include

i) cost recovery

ii) escalating price schedules

iii) market price.

Historically, several unusual asymmetrical situations have existed. In the late 1960's, residual fuel oil contracts provided only for market price declines. However, natural gas contracts of the 1970's allowed only price increases, possibly because of reduced supplies and reserves. Another type of clause, often included in coal and gas contracts, are the take-or-pay provisions that guarantee continued payments regardless of whether fuel has been actually used or not. What such provisions are trying to accomplish, is to balance the risk between sellers and buyers. Past experience has clearly demonstrated though, that no matter how strong the provisions, adjustment to reality always prevails. Expensive contracts have been renegotiated. Cheap contracts have been broken. Recent trends include withdrawal from long-term contracts and increased participation in spot markets. Investor owned utilities, by modifying their fuel purchasing strategies, have reduced their operating costs from 4.5 ¢/KWh in 1986, to 3.5 ¢/KWh in 1995 (both prices in 1995 dollars) [5]. In the past, the use of very long-term coal contracts was the norm for coal-fired plants located both remotely and adjacent to mines. Spot buying has been extensive mainly in cases where utilities have access to numerous nearby coal supplies. Spot buying has enjoyed increased popularity as fuel markets have become more competitive. Nevertheless, although the number of available fuel suppliers does play a significant role, U.S. utilities continued favoring long-term contracts for the bulk of their base fuel supplies. Of interest is that past experience has shown that most coal contracts provide strong protection to sellers.

Natural gas contracts depend heavily on public preassumptions regarding oil prices and availability. Gas contracts peaked in the 1970's under the assumption of continued rising oil prices. When those fears later proved to be unsubstantiated, most of the gas contracts were rearranged and subsequently their numbers declined.

Contracting for residual fuel oil has also been popular in the past. In recent years there has been a shift from a few integrated oil companies dominating the international oil production and marketing to a more competitive and open oil marketplace. The failure of OPEC to sustain artificially high prices and the subsequent expansion of worldwide oil trading, resulted in increasing the advantages of short- and medium-term contracts over long-term ones. Finally, in the nuclear fuel markets, uranium procurement practices shifted from domestically mined products to increased imported supplies subject to DOE's supervision.

Spot markets for fuels varied following demand changes. Sometimes natural gas might not be available as a boiler fuel, especially during prolonged periods of extreme cold conditions.

A final procurement option exercised in the past – at least in the case of coal – was vertical integration (captive supply and demand) [10]. The trend historically was started by few eastern companies and, for many years, involved mines in the proximity of power plants. The trend became widespread in western utilities and, in the 1970's, included coal mines located away from power facilities. This kind of integration has been practically abandoned in the East, as the coal business proved to be too cumbersome and not sufficiently profitable for most utilities. Companies, such as Duke Power, completely withdrew, whereas others, such as American Electric Power, sold the majority of their mining shares. In the West, integration still endures. A more recent trend is where several electric utilities get involved with gas distribution. Among the largest utilities offering electric as well as gas services are Pacific Gas & Electric in California, Consumers Power in Michigan, and Public Service & Gas in New Jersey.

2.5 Environmental Regulation of the Power Industry

During the course of the last few decades, electricity production has been targeted as a major source of pollution. Therefore, the power industry has been subject to the provisions of the many environmental laws enacted in recent years. The Clean Air Act of 1963 and its amendments of 1970, 1977, and 1990 provide the basic legislative framework for air pollution control and abatement. Similar laws have been passed to control water and land pollution. At the state level, power companies have been subject to strict plant siting regulations. Moreover, nuclear facilities need to comply with waste treatment and disposal rules. Table 2.4 provides a partial list of legislation enacted in the last 25 years aiming to protect the environment from further degradation [1].

There are three distinct ways of regulating and controlling emissions [11]:

1) Emission standards, a form of the so called "command and control" approach, may include upper limits on emissions from a particular source, or a maximum allowable emission rate. Such an approach is not considered efficient from an economic point of view, since it does not promote cost minimization.

2) Emission fees are penalties imposed on pollution emitted from a source. This is a more efficient approach, since it allows companies to incorporate emission costs in their scheduling activities and dispatch units on an equal combined incremental cost. Theoretically speaking, the emission charge should be equal to the marginal damage caused by emissions. Practically, such charges are based on aggregate damage or control costs. Some state public utility commissions (PUC)

Table 2.4 Major Federal Environmental Protection Legislation

Year	Legislation
1963	*Clean Air Act*
1967	Air Quality Act
1970	Water and Environmental Quality Act
	Clean Air Act Amendments
1972	Clean Water Act
	Noise Control Act
1973	Endangered Species Act
1976	Toxic Substances Control Act
	National Forest Management Act
1977	*Clean Air Act Amendments*
1979	Pipeline Safety Act
1980	Fish and Wildlife Conservation Act
1981	National Nuclear Waste Policy Act
1990	*Clean Air Act Amendments*

use emission charges (or adders) to monetize the societal costs of emissions in their decisions for future power plant construction.

3) Marketable permits allow regulatory committees to control emission levels and optimize control costs. Each emission credit allows for the emission of one ton of a pollutant. So far, emission permits, called allowances, have been introduced only for SO_2 emissions.

Traditionally, environmental regulations were based on command-and-control methods that practically dictated that certain techniques be used or a particular type of fuel be purchased to reduce emissions. However, the Clean Air Act Amendments (CAAA) of 1990 introduced a novel approach as discussed in section 2.7.

2.6 Pollution Problems from Power Companies

The Environmental Protection Agency (EPA) identified six criteria air pollutants, found throughout the United States:

i) sulfur dioxide (SO_2)

ii) nitrogen oxides (NO_X)

iii) carbon dioxide (CO_2)

iv) lead

v) particulate matter less than 10 microns in diameter (PM_{10})

vi) volatile organic compounds (VOC).

Power producing facilities emit all of the above pollutants, although lead emissions are in insignificant quantities. The share of the electric power plants' emissions is shown in Figure 2.1. Nitrous oxide and methane are included in the figure since they belong in the group of the "greenhouse gases".

Table 2.5 tabulates emission data from fossil fueled U.S. power plants for the last few years [12]. Emissions from coal-fired power plants account for a large portion of the total emissions from all fossil-fueled units. This is true because i) more coal-fired capacity is in use than any other type of fossil fueled capacity, and ii) sulfur is present in virtually any type of coal, in different concentrations. Table 2.6 shows emission estimates for all types of generation, which are however, specific to particular technologies and locations. During combustion, some of the sulfur combines with the oxygen in the air to form SO_2. Production of SO_2 depends mainly on the type of fuel used. This is not the case with NO_X whose

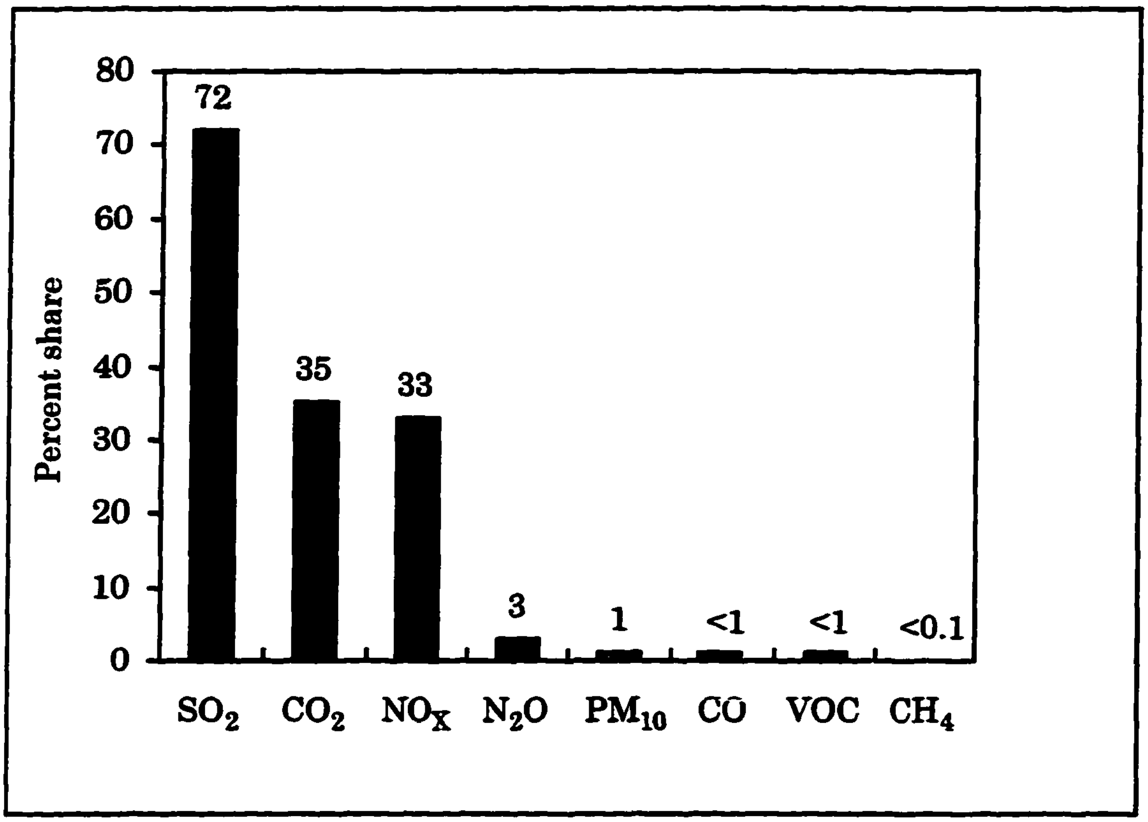

Figure 2.1 Electric Utilities' Share of Total U.S. Emissions in 1993

formation depends mostly on the combustion process rather than on the fuel burned. Nitrogen from the fuel combines with oxygen in the air to form fuel-NO_X. Nitrogen in the combustion air unites with oxygen in the air to form thermal-NO_X. The sum of the two is the total NO_X emissions produced during the combustion process. The most important nitrogen oxide is the nitrogen dioxide (NO_2), which is the compound that gives photochemical smog its characteristic yellowish color. Carbon dioxide is also formed during the combustion process when carbon particles from the fossil fuel unite with oxygen in the air.

Power plant emissions are linked to three major environmental problems: 1) Acid rain includes rain, mist, snow, fog, or hail that is more acidic than normal, as described by its pH. Unpolluted rain has a pH of 5.6, i.e., it is slightly acidic.

Table 2.5 Estimated Emissions from Fossil-Fueled Steam Electric Generating Units at U.S. Utilities (thousand short tons)

Time	NO_X	SO_2	CO_2[1]
1990	7,526	15,633	1,914,093
1991	7,443	15,513	1,907,812
1992	7,188	15,175	1,902,884
1993	7,378	15,014	1,970,193
1994	7,168	14,377	1,972,001
1995	7,135	11,571	1,967,669

[1] As of 1993 data, CO_2 emission from light oil and NO_X emission reduction from control technologies have been revised; historical data have been revised to reflect changes

Table 2.6 Estimated Emissions from Electric Power Generation (tons/GWh)

Fuel Type	SO_2	NO_X	PM_{10}	CO_2	VOC
eastern coal	1.74	2.90	0.10	1,000	0.06
western coal	0.81	2.20	0.06	1,039	0.09
gas	0.003	0.57	0.02	640	0.05
biomass	0.06	1.25	0.11	0[1]	0.61
oil	0.51	0.63	0.02	840	0.03
wind	0.00	0.00	0.00	0	0.00
geothermal	0.00	0.00	0.00	0	0.00
hydro	0.00	0.00	0.00	0	0.00
solar	0.00	0.00	0.00	0	0.00
nuclear	0.00	0.00	0.00	0	0.00

[1] Net emission

Precipitation with pH less than 5.5 is considered acid rain. SO_2 and NO_X in the air react with water vapors in the atmosphere to form acids that are dissolved in the clouds to form acid rain. The highest acidic conditions are found in the eastern United States. Acid rain is blamed for the acidification of surface waters and for the observed damage to spruce trees. It is believed that large acid deposits can threaten the sustainability of many ecosystems.

2) Urban ozone NO_X emissions react in the atmosphere, in the presence of sunlight, to form ozone. Since automobiles are another major source of NO_X emissions, high concentrations of ozone are observed in urban areas. Such high concentrations can cause several health problems, ranging from eye irritations to respiratory problems.

3) Global climate change The group of substances, collectively called "greenhouse gases", is crucial for the existence of life on the planet since they regulate the global temperature and maintain it at the appropriate levels to sustain life forms. However, it is believed that anthropogenic additions to greenhouse gases are increasing the greenhouse effect, thus causing a gradual rise in global temperatures. The major greenhouse gases are carbon dioxide, methane (CH_4), nitrous oxide (N_2O), and chlorofluorocarbons (CFC). The Federal Government has launched the Climate Change Action Plan, a set of 44 actions aiming to stabilize the greenhouse gas emissions at the 1990 levels by the year 2000. Currently, CO_2 emissions are monitored but not regulated and are reported on a voluntary basis.

2.7 The 1990 Clean Air Act Amendments (CAAA)

The 1990 CAAA were the most recent in a series of attempts by the Federal government to establish nationwide air quality standards and pollution abatement regulations. The Act contains eleven titles, five of which affect the power industry. Title IV, acid rain control, mandated a system of SO_2 and NO_X reductions designed to become effective gradually over a period of time. This title introduced a two-phase program to reduce SO_2 emissions by 10 million tons from the 1980 levels. At the completion of the program, an annual nationwide cap will become effective. During the program's first phase, effective January 1, 1995, 261 generating units, explicitly identified in the law, must reduce their emissions to an annual average rate of 2.5 lb of SO_2 per MBtu of input energy. All 261 units, usually referred to as "Table 1 or phase I units", are located on the eastern half of the United States. Power companies have designated an additional 174 compensating units, based on the EPA rules that allow utilities to declare substitution units as part of their phase I compliance plans. Hence, a total of 435 units are currently participating in the first phase of the SO_2 emission control plan. Phase II, which begins January 1, 2000, establishes more stringent SO_2 emission limits. At that time, all 25 MW or greater generating units will be allowed to emit a maximum of 1.2 lb/MBtu. It is expected that 2000 units will be covered by phase II. Nationwide total SO_2 emissions will be capped at 8.9 million tons annually, which is a significant reduction compared to the 14.8 million tons of SO_2 emitted in 1993. Power facilities will be required to possess sufficient emission allowances to cover their emissions. The innovative concept of marketable emission allowance, discussed in a later section, gives the bearer the right to emit one ton of SO_2.

Title IV also regulates NO_X emissions. The same 261 units, identified in the bill, must reduce their NO_X emissions by 2 million tons during phase I. Coal-fired electric power plants are required to meet maximum permissible emission rates that vary with the type of boiler. For instance, wall-fired units are limited to 0.5 lb/MBtu and tangentially-fired units are limited to 0.45 lb/MBtu. The EPA is directed to conduct further studies to determine whether additional measures and limits are necessary. NO_X emissions are additionally addressed in Title I of CAAA since NO_X is considered a precursor to ozone formation. NO_X, under Title I provisions, may be treated as a non-attainment pollutant, and in non-attainment areas stricter NO_X standards may be established. It is expected that efficient NO_X control strategies will be more effective in controlling urban ozone than regulating VOC. In general, current NO_X regulations are not considered stringent enough to alleviate the problem of ozone formation in areas of high urban concentration, such as the Los Angeles basin.

Title III regulates air toxics, i.e., 189 substances that present a possible threat to public health. Although power producers are not currently regulated under this title, 37 air toxics are detected in power plant stack gas. Titles V and VI provide for compliance means and expand the authority of EPA to issue penalties and citations. Plant supervisors are personally subject to imprisonment in case a plant violates the new standards.

Overall, the CAAA introduced a new approach to emission control. Recent studies by the EPA and DOE indicate that the emission targets have been reached thus far. Although the amendments are expected to be successful in establishing national compliance standards, they will result in a disproportionate distribution of emissions. As is suggested in [11] possible refinements might allow for varying standards in accordance with the different levels of damage from SO_2.

2.7.1 Power Industry Compliance with the 1990 CAAA

At the end of 1995, the first year of phase I of the emission reduction plan, all affected units were found to have complied with the CAAA requirements. Some analysts suggested that with low sulfur coal prices steadily declining, most utilities would have switched to low sulfur coal and emissions would have been reduced. However, no matter what the driving motivation, phase I units emitted 5.3 million tons of SO_2 in 1995, well below the EPA goal of 8.7 million tons and 50% lower than their estimated 1985 emissions of 10.5 million tons. Table 2.7 shows the share of phase I units to total emissions during the last decade.

Table 2.7 Comparison of SO_2 Emissions from Phase I and Non-Phase I Units (million tons)

	Capacity (GW)	Total SO_2 Emissions			
	1995	1985	1990	1994	1995
Phase I Units	130.9	10.5	9.7	8.0	5.3
Non Phase I Units	333.2	5.1	5.9	6.3	6.6
Total	**464.1**	**15.6**	**15.6**	**14.4**	**11.9**

The CAAA differed from previous regulatory efforts to control emissions in that it offered utilities much flexibility in choosing their compliance strategies as well as access to marketable emission permits. A recent study by the DOE [1] indicated that fuel switching and/or blending was the most favorable compliance strategy. 136 phase I units chose this action resulting in 59% of the total SO_2 reduction achieved in 1995. Scrubbers installed by 27 units accounted for 28% of the total SO_2, whereas 83 units obtained additional allowances and 7 units were retired. The remaining 8 phase I units chose different plans, unspecified in the DOE report. Figures 2.2 and 2.3 present a visual summary of these results[1].

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[1] Figures 2.1 and 2.2 do not include substitution and compensating units; presented data cover only the original 261 phase I units

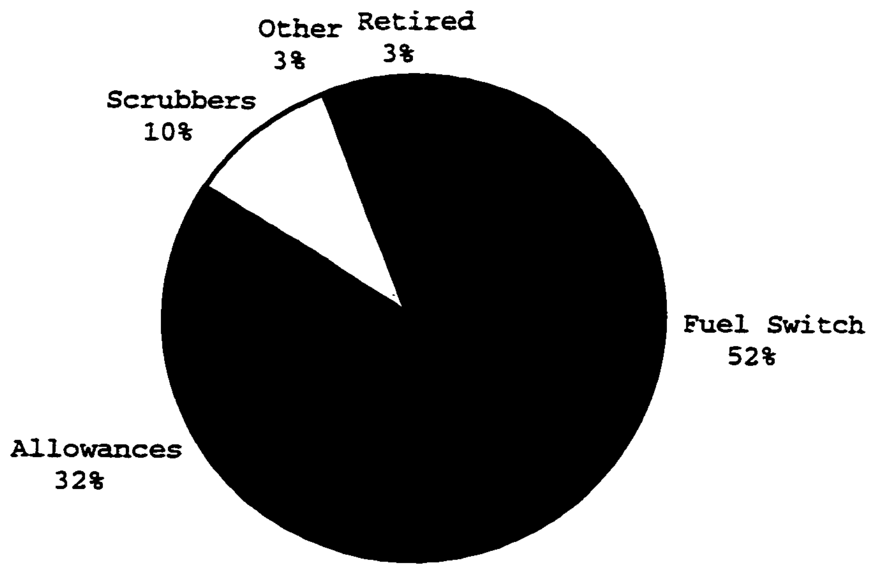

Figure 2.2 Compliance Methods used by Table I Units in 1995

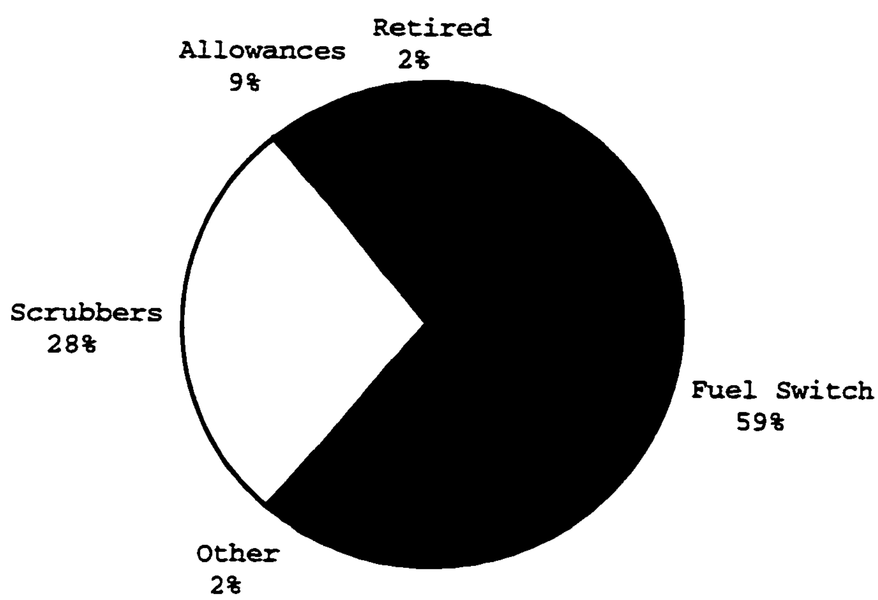

Figure 2.3 Achieved SO_2 Reduction by Compliance Method in 1995

Before implementation of the emission control program, installing scrubbers was expected to be the method of choice for the majority of power plants. The fact that this prediction did not actually materialize is attributed mainly to scrubber costs and declining coal prices as well as to the failure of state legislators in Illinois and Indiana to enact laws protecting their local high sulfur coal productions. Recent technological advances in scrubber technology have made them efficient up to 99%, removing more SO_2 than required and, thus, creating a surplus of allowances for the utilities installing them.

Power industry compliance with the new environmental regulations did not come without cost. In a preliminary report, analysts at MIT estimated an annualized cost of $836 million [1]. The establishment of an emission allowance trading program is credited for SO_2 compliance costs lower than initially predicted. Data indicates that scrubbers were the most expensive option with an annualized average cost of $322 per ton of SO_2 removed. The cheapest option was switching bituminous plants to burn low-sulfur subbituminous coal at an annualized average cost of $113 per ton of SO_2 removed.

The situation is somewhat more complicated for NO_X. The EPA finalized NO_X regulations as late as April 13, 1995, following court challenges from utility groups on previous rulings. The deadline for compliance was extended to January 1, 1996, and it is estimated that annual NO_X emission from phase I tangentially- and wall-fired boilers would be reduced by 400,000 tons, beginning in 1996.

Phase II will cover virtually all fossil-fired generating units. The SO_2 emission limits are stricter and the availability of emission allowances will be limited. Several companies have announced their plans to defer scrubber installation until phase II. In addition to phase I options already exercised, repowering unused or underutilized units seems a likely additional option. NO_X regulations will be stricter. Maximum allowable emission rates will be further reduced from phase I levels. Moreover, power producers are encouraged to consider and examine options that are capable of simultaneously reducing additional pollutants that are not currently under regulation, e.g., particulates, mercury, etc.

2.7.2 Emission Allowances

The introduction of the novel concept of tradable emission allowances completely changed the underlying philosophy of the emission controlling programs since it provides a market-based mechanism to achieve compliance. The EPA supplies emission allowances annually at auctions taking place each March. Additional allowances are available from scrubbed plants as well as from plants switching to lower sulfur fuels. Allowances may be traded in direct interutility transactions without participating in the annual auctions. They can be used immediately or banked for future use. Prices in recent auctions have been much lower that what was estimated at the time of passage of the CAAA. In the 1993 EPA conducted auction, minimum winning bids started at $131 whereas minimum successful bids started at $150 in the 1994 auction [13]. Prices for later auctions were not readily available. These prices were valid for the spot auction, i.e., allowances are immediately usable. In auctioning a separate set of allowances, usable after seven or more years (advance auction), prices were somewhat lower. The relatively low prices attracted several companies and allowances were used by many plants to comply with phase I requirements and defer the high costs of scrubber installation until phase II. They were also considered an attractive means to hedge against the uncertainty surrounding phase II, especially in a highly competitive environment. Allowance markets have already been established and sophisticated financial instruments, such as contracts, futures, and contracts, are available. The way allowance auctions are performed has received much criticism focusing mainly on the lack of a minimum winning price as well as on the existence of multiple winning prices in the current auctioning mechanism [1]. In response, the EPA issued an advanced notice of proposed rulemaking asking for suggestions for changes in the current auction design. However, since emission allowance markets already have existed for a number of years and market prices are established, the current format was deemed to not any more misinform the markets. Although changes in the early years, 1993 and 1994, might have been helpful, the EPA recently announced that it has no plans to change the auction format.

Emission allowances are expected to play an equally important role during phase II, although prices are expected to rise. Some concerns have surfaced about the way allowances are taxed, arguing that the current system favors internal utility use and, thus, impedes the formation of free, competitive markets. However, these problems are supposed to be addressed by the Congress.

So far the experience from the emission allowance program has been very positive. Not only has it helped to produce SO_2 emission reduction faster and in a less costly manner, but it also has provided incentives for economic improvization. Some high-sulfur coal-burning companies actively participated in allowance trading and acquired allowances that were bundled with their coal produce, thus increasing their competitiveness. Although emission allowances are currently issued only for SO_2, their success has supported discussions to expand the program to cover additional pollutants.

2.8 Emission Regulation and Fuel Consumption

According to the DOE projections, coal maintains its cost advantage over alternative fossil fuels. When the CAAA phase II emission requirements become effective, gas-fired generation seems to be the most economical choice through the year 2010. Beyond that time point, coal is expected to resume its leadership among fossil fuels for newly constructed base-load capacity.

As expected, the CAAA requirements affected the operation of the U.S. coal industry. Demand for low-sulfur coal increased whereas production in high-sulfur coal mines dropped significantly. Improved mining technologies as well as reduced transportation costs, partly because of increased railroad competition, resulted in decreased fuel prices. The U.S. average delivered cost of low-sulfur coal fell from 46.25 \$/short ton in 1985 to 27 \$/short ton in 1995 (comparison in 1995 dollars) [1]. The fuel delivered price includes the mine price plus transportation and loading expenses, and accounts for up to 75% of the operating costs of a power plant.

In 1995, low-to-medium sulfur coal accounted for 77% of total coal receipts at power producing facilities, compared to 67% in 1990. The Powder river basin became the leading coal supply region leaving the central Appalachian region in the second spot. Orders from Wyoming and Montana mines increased substantially. The transitional period however, did not make winners only. High-sulfur coal production in the Illinois basin was significantly reduced resulting in drastic reduction in the number of mines operating in the region. The number of miners employed fell an average 10%/year in the high-sulfur coal producing states of Illinois, Indiana, and Ohio. Although state legislators attempted to protect their local coal industries, the Alliance for Clean Coal, a coalition of western coal mines and railroad enterprises, was successful in having the proposed legislation blocked and finally struck down.

In most past approaches to simulate daily generation scheduling activities, fuel resources and emission compliance were regarded as two disassociated areas of operation. However, as it is clear from the discussion in the previous sections, there exists a strong interdependence between fuel and emissions in the power industry. Fuel regulatory policies were always taking into consideration possible environmental consequences, whereas emission regulations determined fuel consumption patterns. Such an interdependence should not be overlooked by power producers in planning and operating activities. One of the major goals of this work has been the development and implementation of an operational framework integrating fuel and environmental considerations.

2.9 Open Access and Environmental Concerns

Environmentalists, together with advocates for energy conservation programs, were very concerned with the possible harm induced by the FERC's orders 888 and 889. Especially for NO_X, open access might permit old, dirtier plants to increase generation. Responding to these concerns, the FERC prepared an Environmental Impact Statement (EIS), which concluded that implementation of open access, as described in orders 888 and 889, would cause minimal changes to NO_X emissions, in general below 2%. The study indicated that NO_X emissions are more sensitive to relative fuel price changes than to open access. In fact, it was reported that with a constant ratio of natural gas to coal prices, total NO_X emissions might end up reduced in an open access environment. The Energy Information Agency (EIA) of the DOE conducted also an independent study on the same subject, in response to a U.S. Senate request, which reached similar conclusions. Regarding emission standards, open access' impact is small compared to the impact of electricity demand growth. Again, such an impact was found to be less than 3%. The key result was that, with or without open access, SO_2 and NO_X emissions will increase as a result of growing electricity demand

and the retirement of nuclear facilities. Additional NO_X measures, if implemented, may succeed in keeping NO_X emissions below the 1994 levels, through the year 2015 [14].

On a state level, environmental groups opposed direct transmission access fearing that if the focus is shifted on reduced costs, external costs of fossil fuel generation may be overlooked and projects for cleaner generation will not be able to compete [11]. Additional problems arise regarding jurisdictional considerations since electricity markets, in all probability, will cross state boundaries. Utility executives have indicated that not all of the new power producing entities that will enter the electricity markets are subject to similar emission regulations, thus creating an uneven playing field. A complicated situation is foreseen when power producers under the jurisdiction of a state PUC compete with out-of-state producers that have to observe different, possibly less restrictive emission regulations. If potential damages to public health are viewed as real economic costs, additional intervention at the federal level will be necessary to address environmental externalities resulting from transactions transcending state lines.

3. FUEL-CONSTRAINED DISPATCH

This chapter considers the dispatch problem when additional constraints, stemming from the supply side, are applied. The first section of the chapter provides a literature review, followed by the mathematical formulation of the traditional economic dispatch problem, which is presented in the second section. Section 3.3 presents the dispatch problem when fuel resources are supplied using escalating price schedules and section 3.4 further augments the problem to include cases of limited fuel supplies. Section 3.5 discusses the solution approach taken to solve the overall problem and the section 3.6 presents numerical results. The final section provides a chapter summary. Although fuel storage is mentioned in this chapter, it was not included in the actual implementation.

3.1 Literature Review

Fuel-constrained dispatching may include constraints introduced by the fuel network limitations, existence or lack thereof of storage facilities, fuel availability, fuel contractual agreements, and various combinations of the above constraints. Fuel-constrained unit commitment and resource scheduling are two topics addressed in the literature. Traditionally, the fuel constraints included in scheduling and operational planning algorithms were a rather simple representation of the fuel network. Moreover, in most of these approaches, it was assumed that the availability of sufficient fuel supplies is guaranteed, at given fixed prices. This is an oversimplified representation of today's complex fuel markets. Fuel supplies and their marketing must receive additional attention because of their importance in reducing utilities' total operating costs, thus increasing their chances to succeed in the competitive new environment.

Lamont *et al.* [15,16,17] presented some of the first papers dealing with the fossil fuel scheduling problem. Different approaches, such as the out-of-kilter and the reallocation algorithms, were used to solve the problem. The papers by Kumar, Vemuri and their group treated the entire fuel resource scheduling problem in a very methodical way. In the first of their papers [18], fuel resource scheduling was considered as an integrated part of an energy management system. Technical considerations and required pieces of data were presented. In subsequent papers, the long- as well as the short-term fuel scheduling problems were addressed [19,20,21]. The same problem was also treated within a daily (24-hour) time frame [22]. The problem was formulated as a network flow optimization problem and minimum cost network flow algorithms were used to solve it. The same problem was revisited more recently by Vemuri *et al.* [23] and was solved by means of a decomposition strategy that decouples the overall problem into a fuel dispatch and a generation dispatch.

The same authors applied a similar decomposition approach in their treatment of fuel-constrained unit commitment [24]. This problem was decoupled into a fuel dispatch and a separate unit commitment problem. Alternative solutions for the same problem were presented in several other papers [25,26]. All of these approaches considered fuel constraints of different levels of complexity. In most cases, variants of Lagrangian multipliers methods were the solution approach chosen.

Van Meeteren [27] used dynamic and linear programming techniques to solve the optimal fuel allocation problem. A hierarchical structure was developed that combined the fuel allocation and unit commitment problems. In their treatment of fuel allocation, Lee *at al.* [28] used an adaptive scheme utilizing the concept of pseudo fuel prices as decision variables.

Asgarpoor's review paper [29] compared linear, nonlinear, and network flow techniques applied to the fuel scheduling problem. Other methods used to solve the same problem were Karmakar's interior point algorithm [30], genetic algorithms combined with simulated annealing and fuzzy sets [31], and more recently fuzzy linear programming [32]. At a practical level, Rosenberg *et al.* [33] in their paper, presented the actual practices for fuel scheduling and accounting employed in Houston Lighting & Power Company. Contractual agreements were taken into serious consideration since penalties for violations were "significant."

The paper by Newdome *et al.* [34] focused on the modeling of blending and transloading facilities. Such facilities are used to mix different types of coal, primarily for the purpose of sulfur content reduction. An interesting paper by Moslehi *et al.* [35] is one of the few in the literature that included fuel supply constraints in the optimal fuel procurement formulation. The whole process, from the time the fuel is purchased until the time the fuel is consumed, was included in the model. Linear programming techniques were used to solve the overall problem. To reduce the problem dimensions, fuel prices were prorated and fuel sources were aggregated. Gibson *et al.* [36] addressed the dependence of optimal fuel procurement on accurate fuel pricing. Different formulations of fuel prices were used and compared and the sensitivity of the total fuel cost with respect to the various fuel pricing methods was analyzed. Potential spot market purchases were also considered. The paper concluded that incremental fuel prices should be used to correctly dispatch generation, when multiple sources of fuel, with different prices and constraints, are available. Incremental fuel pricing was used throughout this research work.

Overall, although the fuel dispatch problem has been addressed sufficiently in the literature, the focus was on the complications introduced by the fuel networks, as well as on the interface between fuel allocation and the more general problem of unit commitment. Fuel supply considerations received limited attention and prices were assumed fixed at given levels. Models for limited energy supplies were not included in most dispatch algorithms of the past.

3.2 Economic Dispatch Formulation

Dispatching provides set points for regulatory action applied to the generating units operating within a controlled system, in order to allocate generation on an optimal basis so that an objective function is satisfied subject to obeying a set of fundamental constraints. Although economics are still the dominant factor and minimization of the operating costs is the ultimate objective, imposing additional constraints has resulted in the development of different dispatching practices involving emission constraints, fuel constraints, security constraints, etc.

3.2.1 Unit Modeling

The hourly fuel input to a generator is a function of its power output. Several mathematical functions have been used to model this quantity, such as quadratic, full and reduced cubic, polynomial, exponential, combinations thereof, etc. This function may also consist of one or more segments, each segment being modeled by an appropriate mathematical expression. Oftentimes, the original nonlinear function is approximated, through appropriate segmentation, by a set of linear functions. Reduced cubic functions are used in this work to model fuel input. The main advantage of the reduced cubic formulation is that its first derivative is a monotonically increasing, nonlinear function, which is a desirable property – as well as necessary for many solution algorithms – in order to more realistically represent actual nonlinearities of the incremental fuel rate. The quadratic term is omitted to avoid possible negative slope regions. The reduced cubic formulation for fuel consumption of the i^{th} unit during the j^{th} time period (hour) is given by

$$F_{i,j} = f_{i,a} + f_{i,b}P_{i,j} + f_{i,d}P_{i,j}^3 \qquad \text{(Eq. 3.1)}$$

where all the coefficients have positive, non-zero values, $f_{i,\cdot} > 0$. The values of the fuel equation coefficients are based on (1) initial design, (2) acceptance testing, and (3) periodic testing. In the future, a fourth method, continuous monitoring, may be utilized although it has been tried in the past without much success. The accuracy of the fuel consumption representation as well as the associated costs improve from method 1 to 3. The corresponding hourly operating cost of each generating unit is the product of the fuel consumed and the associated fuel price

$$C_{i,j} = F_{i,j}U_i \qquad \text{(Eq. 3.2)}$$

The objective of economic dispatch is to minimize total operating cost, which is the sum of individual unit costs taken over all units operating within the system over the dispatch period. In some planning applications, multiple periods are involved, which was the case considered during this research work, and the goal is to minimize the total operating cost over the entire set of time periods. If no change in commitment patterns is considered, the objective is given by

$$\textit{minimize} \qquad \sum_{i=1}^{G}\sum_{j=1}^{H} C_{i,j} \qquad \text{(Eq. 3.3)}$$

Since the second derivative of unit fuel cost is positive over the entire range of power output values, the objective function is a convex function.

3.2.2 Additional Constraints

Each generating unit on automatic control must be operated between its minimum and maximum power output limits

$$P_i^{Mn} \leq P_{i,j} \leq P_i^{Mx} \qquad \text{(Eq. 3.4)}$$

If transmission losses are neglected, the total generation for a lossless islanded system in each hour must equal the forecasted system load (power required) during that hour

$$\sum_{i=1}^{G} P_{i,j} = P_j^R \qquad \text{(Eq. 3.5)}$$

In general, power generation requirements for a given hour are the sum of the forecasted system load during that hour plus the power system losses plus the scheduled power sales minus the scheduled power purchases

$$P_j^R = P_j^{LOAD} + P_j^{LOSSES} + P_j^{PURCHASES} - P_j^{SALES} \qquad \text{(Eq. 3.6)}$$

The set of Equations (3.3)–(3.6) constitutes the mathematical formulation of the basic economic dispatch problem used in this research. This basic model can be largely expanded incorporating more "real world" limitations. In the next sections, additional constraints are included in the basic model and they transform it into a fuel-constrained dispatch model.

3.3 Cost Minimization using Fuels with Escalating Prices

3.3.1 Problem Formulation

The basic economic dispatch model assumes each unit's fuel prices are fixed at single levels. This approach, i.e., associating a single level fuel price with each type of fuel, has been a common practice in the past. Moreover, those prices were independent of the amount of fuel consumed.

Today, utilities are not limited in their selection of fuel suppliers. Rather, they have access to several fuel markets and are free to request bids and accept offers for fuel purchases at the prevailing market prices. They have the ability to renegotiate or buy out existing contracts if their prices do not deem to be competitive. Individual fuel contracts often consist of multiple blocks, each block being associated with a different price. Usually the first block is more expensive and prices decrease as more fuel is acquired. The first block must be entirely consumed before the second block becomes available. In this way, the utility-customer is tempted to increase the purchased amount of fuel from a single contract in order to realize increased savings by buying cheaper blocks of fuel. Since utilities have to completely use a block of fuel before they may use the next block, the consumption of blocks within a contract is serially prioritized. Some of the lowest numbered blocks may require a minimum amount to be consumed (take-or-pay clause). The situation is complicated since utilities may enter into a variety of contractual agreements, i.e., utilities have access to multiple fuel suppliers in order to obtain the best price and provide redundancy. Figure 3.1 shows a typical fuel contract structure.

The problem that utilities face, given a forecasted load and a set of available contracts, is how much fuel to purchase from each source and how to merge the available contracts in order to assure minimum fuel cost. This problem is mathematically formulated as follows for the mth block in the kth contract:

$$\textit{minimize} \qquad \sum_{k=1}^{K}\sum_{m=1}^{B_k} V_{k,m} U_{k,m} \qquad \text{(Eq. 3.7)}$$

where Equation 3.7 represents the total cost of all fuel contracts used,

subject to

$$V_{k,m}^{Mn} \leq V_{k,m} \leq V_{k,m}^{Mx} \qquad \text{(Eq. 3.8)}$$

Fuel Block	Price	Required Minimum (MBtu)	Maximum Available (MBtu)
1	1.35	30,000	50,000
2	1.20		50,000
3	1.15		50,000
4	1.12		75,000
5	1.10		75,000

Figure 3.1 Typical Configuration of a Fuel Contract

where Equation 3.8 represents the maximum available fuel limit constraint for block m of contract k,

$$\sum_{k=1}^{K}\sum_{m=1}^{B_k} V_{k,m} = W \qquad \text{(Eq. 3.9)}$$

where Equation 3.9 represents the fact that the total fuel used should exactly equal the actual system fuel needs including any storage replacements,

$$V_{k,m}(V_{k,m-1} - V_{k,m-1}^{Mx}) = 0, \qquad k = 1,\ldots,K, \;\; m = 2,\ldots,B_k \qquad \text{(Eq. 3.10)}$$

where Equation 3.10 models the constraint that a fuel block is used after the previous blocks within the same contract have been used.

3.3.2 Optimal Ordering of Fuel Contracts

The optimal ordering of fuel contracts, as expressed mathematically in the previous section, is a nonlinear problem. A complete enumeration based mechanism has been developed and is explained in this section. This mechanism has undergone evaluation and testing using a proof-of-concept, dynamic progarmming based software [37] to compare respective output results.

Fuel blocks are divided into those that have a minimum required fuel take (take-or-pay blocks) and those that do not. Utilities are expected to pay the cost of a take-or-pay fuel block regardless of actually accepting its delivery or not. Under this type of penalty, it is always to the utility's benefit not to violate fuel contracts and to consume or store at least the minimum required quantities (if any). If a contract violation occurs and is detected, fuel prices are adjusted. By means of pseudo fuel prices, the required fuel take is "forced" to be consumed.

If multiple minimum required quantities exist within a set of fuel contracts, they are sorted to be used in a decreasing price order starting with the highest price quantity. This ordering does not make any real difference under the current model of the penalty costs, explained in the previous paragraph. However, this ordering seems to be the optimal one in different, less strict models of the penalty costs, in which utilities might need to pay a portion only of the costs of the unaccepted minimum required quantities. If such a penalty model is selected, the appropriate terms may need to be added to the objective function of the problem, reflecting the effects of the penalty cost provisions on the total system cost. However, under the current penalizing assumptions, such terms are unnecessary and the objective function is as presented in the previous section.

In order to develop a composite fuel block ordering for the remaining non take-or-pay fuel blocks, all possible combinations of fuel blocks are considered. The assumption that blocks within the same contract are consumed in a strictly serial manner must be taken into account during that process. The cumulative fuel costs are then calculated and tabulated for all possible combinations and for certain levels between minimum and maximum fuel consumption. The chosen levels include a maximum common step size between blocks in all contracts. Not all of these points are of any interest, however. Costs need to be calculated at those consumption levels where a fuel block is totally consumed. From such a table, the optimal ordering of fuel blocks is easily traceable as a function of fuel consumption. As a last step, costs at break-even points between different combinations must be calculated when a switch between combinations occurs. These break-even points are the actual consumption levels where it is more economical to switch from one contract to another. In all test cases evaluated (approximately 100 different cases), the initially very large number of possible combinations finally collapses to a small number of patterns.

If there exists a take-or-pay fuel block for which the required minimum fuel quantity is less than the maximum available fuel quantity of that block, then the block is effectively split into two (sub)blocks. The first one will include the minimum required quantity and will be ordered as a take-or-pay block. The second one will include the remaining portion of the fuel (maximum minus required minimum) and will be ordered as a non take-or-pay fuel block.

Contract ordering is an one time activity and need not be repeated as long as no contract data is modified or the contract time period is not changed. Generally, the time period used for billing in fuel contracts is one month. Decisions involving periods of different lengths of time require the appropriate prorating of the contract data. Once an ordering is established, the fuel consumption levels corresponding to a dispatch schedule are compared against the contract sequence to determine whether the appropriate fuel incremental prices have been used in dispatch calculations. In case of a discrepancy, fuel prices are updated and dispatch calculations are repeated using the new set of fuel incremental prices. This process iterates until fuel prices and corresponding fuel usage are in agreement with the optimal contract sequence.

The same problem can also be solved by means of several optimization methods. As already stated, a dynamic programming based program was used for comparison reasons. Also, modeling software, such as GAMS and AMPL, could be used to set up and solve models of this problem.

3.3.3 A Typical Example

A typical problem is presented in this section to demonstrate the process that leads to the optimal consumption ordering of multiple fuel contracts. Assume that a group of units has access to the three fuel contracts tabulated in Table 3.1. Applying the ordering mechanism, the various fuel blocks are ordered optimally as shown in Table 3.2. Given the forecasted load, this group of units will consume the amount of fuel corresponding to that load level. The fuel data shown in Table 3.2 are actually used as fuel input for some of the units in the test cases presented in a later section.

3.4 Dispatching with Limited Fuel Supplies

Although the contract ordering does enhance the basic dispatch model, described by Equations (3.3)–(3.5), by providing an optimally arranged escalating fuel price schedule, the dispatch model can be further expanded to accommodate situations of constrained fuel supplies, such as take-or-pay fuel blocks or limited availability of certain types of fuel [38]. To accomplish this, the power system is partitioned in *fuel groups*. A fuel group is defined as an all inclusive set of units or power plants having access to a particular set of contracts or a particular type of fuel. The concept of fuel groups was originally proposed by Lamont *et al.* [15] to identify subsections of fuel networks in order to decouple complex natural gas supply networks into more tractable parts. This concept was expanded in this work. The focus is no longer on fuel networks; rather it is on the modeling of the fuel supply contracts and their impacts. Once the system is partitioned in fuel

Table 3.1 Fuel Input Data for Multiple Fuel Contracts

Fuel Block	Required Minimum	Available Maximum	Price
A1	200,000	200,000	1.436
A2	50,000	250,000	1.384
A3		300,000	1.311
A4		400,000	1.286
B1	75,000	100,000	1.442
B2		120,000	1.323
B3		160,000	1.281
B4		220,000	1.154
C1	25,000	50,000	1.488
C2		100,000	1.445
C3		250,000	1.337
C4		350,000	1.250
Totals	350,000	2,500,000	

groups, an optimally ordered fuel contract sequence is associated with each fuel group. Two limiting cases are considered. First is the case when there exists a minimum required fuel quantity that must be consumed (take-or-pay blocks). Second, the case when the available quantity of a particular fuel group is severely constrained (over-the-limit consumption). These two cases are described by

$$\sum_{i\in\vartheta}\sum_{j=1}^{H} F_{i,j} \geq F_{\vartheta}^{Mn} \qquad \text{(Eq. 3.11)}$$

$$\sum_{i\in\vartheta}\sum_{j=1}^{H} F_{i,j} \leq F_{\vartheta}^{Mx} \qquad \text{(Eq. 3.12)}$$

Table 3.2 Optimal Ordering of the Fuel Blocks of the Typical Example

Fuel Quantity	Cumulative Fuel Cost	Incremental Fuel Price
25,000[1]	*501,750*	*N/A*
100,000	*501,750*	*N/A*
300,000	*501,750*	*N/A*
350,000	*501,750*	*N/A*
398,770	569,248	1.384
495,000	696,560	1.323
655,000	901,520	1.281
875,000	1,155,400	1.154
1,075,000	1,432,200	1.384
1,375,000	1,825,500	1.311
1,433,333	1,900,516	1.286
1,600,000	2,108,850	1.250
1,661,224	2,193,584	1.384
1,775,000	2,339,900	1.286
1,800,000	2,377,100	1.488
1,863806	2,469,300	1.445
2,100,000	2,778,950	1.311
2,500,000	3,293,350	1.286

[1] Take-or-pay fuel blocks in italics

respectively. Including the above two equations in the constraint set of the basic dispatch model and requiring additionally that dispatch results conform with the optimal fuel contract ordering, provides an enhanced fuel-constrained model.

The Lagrangian of the new model is given by

$$L=\sum_{i=1}^{G}\sum_{j=1}^{H}C_{i,j}+\sum_{j=1}^{H}\lambda_j(P_j^R-\sum_{i=1}^{G}P_{i,j})+$$
$$\sum_{i=1}^{G}\mu_i^{+}(P_i-P_i^{Mx})+\sum_{i=1}^{G}\mu_i^{-}(P_i^{Mn}-P_i)+ \qquad \text{(Eq. 3.13)}$$
$$\sum_{\vartheta=1}^{O}\mu_\vartheta^{+}(\sum_{i\in\vartheta}\sum_{j=1}^{H}F_{i,j}-F_\vartheta^{Mx})+\sum_{\vartheta=1}^{O}\mu_\vartheta^{-}(F_\vartheta^{Mn}-\sum_{i\in\vartheta}\sum_{j=1}^{H}F_{i,j})$$

For those fuel groups, whose fuel consumption is within limits, the associated multipliers μ_ϑ^- and μ_ϑ^+ will be equal to zero. This includes the case when fuel constraints don't exist. Whenever a fuel consumption constraint is binding, the corresponding multiplier takes a nonzero value.

3.5 Solution Algorithm

Classical optimization theory provides an abundance of possible approaches to solve a nonlinear problem. Two large groups of these methods are the primal and the dual methods that treat the primal or the dual formulation of the problem respectively. In the case of linear programming, methods are analogously classified as row generation – analogous to primal – and column generation – analogous to dual – techniques. Several excellent optimization books are available that address both the linear and nonlinear cases [39,40,41,42]. Dual approaches are price directive in the sense that the optimization process depends on the updating of "shadow prices" or objective function weighting coefficients. This can be accomplished by the use of the convenient concept of the Lagrangian multipliers. As is explained in the relevant literature, the economic interpretation of the Lagrangian multipliers is that they correspond to marginal prices, i.e., prices associated with small variations in the constraining functions. In the case of multiple constraints, a decomposition and coordination scheme is developed and a series of smaller-sized subproblems are solved iteratively. Such a sequence leads to an optimal solution point if such a point exists.

A flowchart for the overall solution algorithm is shown in Figure 3.2. The optimal contract ordering is handled as an initial pre-dispatching step. The initial dispatch is performed using arbitrary incremental fuel prices and at its completion, the fuel consumption levels of the various fuel groups are compared against the optimal contract sequence to determine if the appropriate incremental fuel prices were used. If violations are detected, the incremental fuel prices are updated and the procedure iterates until the fuel consumption levels for all fuel groups and the incremental fuel prices used in the dispatch process converge and are in accordance to the optimal contract ordering. This completes the first phase of our solution algorithm. Initially, all Lagrangian multipliers are assumed to be equal to zero, i.e., their respective constraints are not binding. At the completion of the first phase, optimal values for all λ_j are found as well as optimizing values for μ_i^+ and μ_i^-.

Since Lagrangian multipliers may be viewed as the price to pay to satisfy the corresponding constraints, the multipliers μ_ϑ^- and μ_ϑ^+ act as pseudo incremental prices, reducing or increasing the relative price of a particular type of fuel. The incremental price for a fuel group may be reduced to increase its fuel consumption and thus, satisfy take-or-pay requirements. Conversely, it may be necessary to increase a fuel contract's incremental price to limit its consumption, thus, bringing it within the available quantities.

After the first phase, take-or-pay or over-the-limit consumption constraints are addressed [38]. The problem is decomposed following the physical partitioning of the power system into fuel groups. For each fuel group, one of the two possible types of violations may occur, but obviously not both of them at the same time. Fuel groups are checked sequentially and all violations

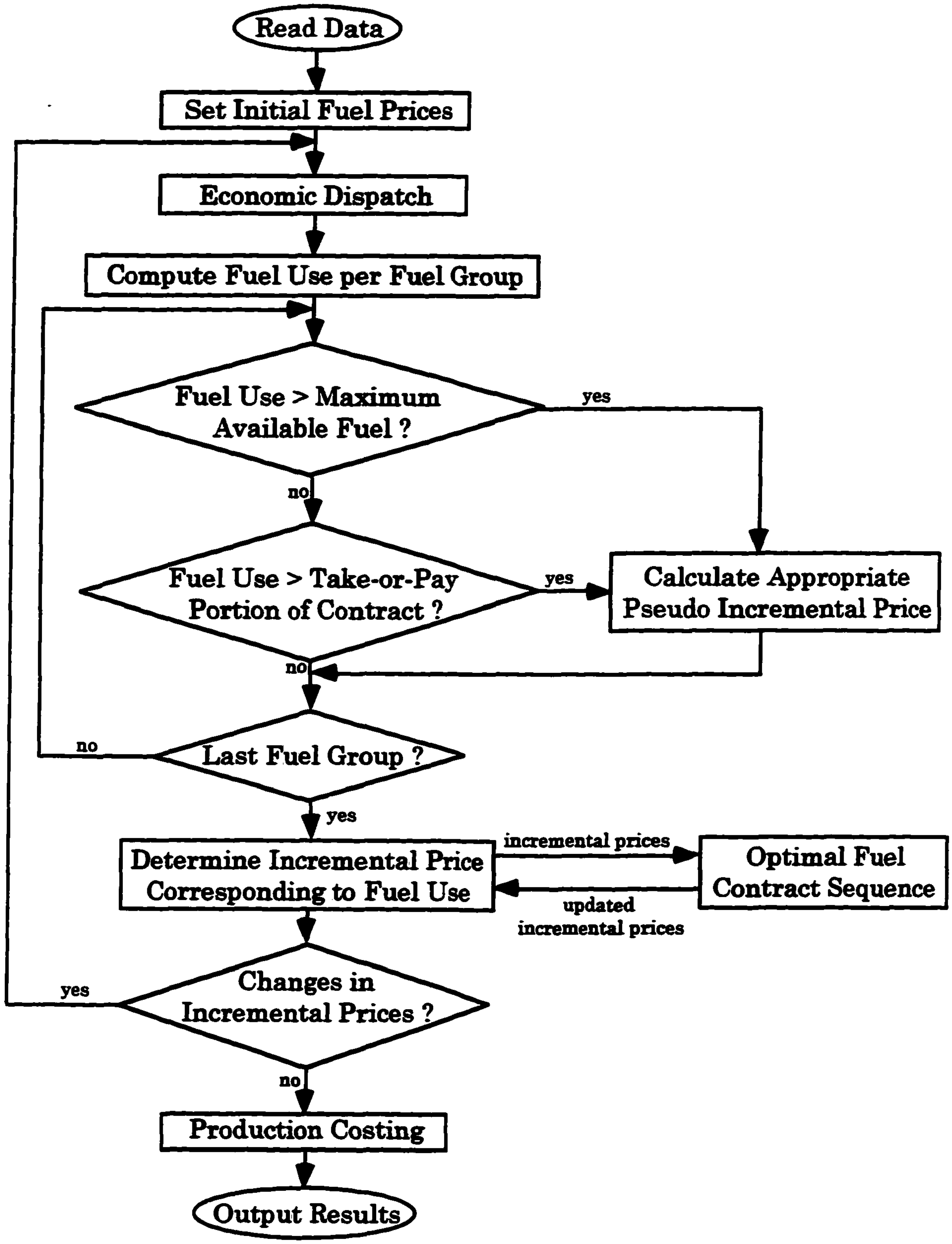

Figure 3.2 Fuel-Constrained Dispatch Solution Flowchart

are handled accordingly. In that sense, there are no priorities in the order a violating fuel group enters the active constraint set. Once a violation is detected, the corresponding multiplier needs to be updated. This updating is performed using a single-dimensional search algorithm. The bisection algorithm was used in this work, but other search schemes, such as the secant search algorithm, could be used as well. The search range is defined considering the cheapest and most expensive fuel prices within the power system. Once a pseudo fuel price is determined that satisfies the violated constraint, the violation check continues with the next fuel group and so on. However, it is clear that updating the pseudo incremental price of a fuel group may cause deviations in the consumption of groups that have been already checked. These groups need to be rechecked and their pseudo incremental prices need to be readjusted considering however, the updated values of the remaining Lagrangian multipliers. This whole iterative process cycles as necessary until all violations are corrected.

An alternative approach to search for violations is by type of violation. Obviously, over-the-limit consumption violations are more serious and need to be addressed first, since the generating units in violation are in need of fuel supplies that are not physically available. On the other hand, take-or-pay violations have an end result of increasing the operating costs of the system. An additional refinement is to treat violations within each group of violations based on their "magnitude". It is our experience that in some test cases, correcting a few, relative large violations, simultaneously took care of several of the constraints of the opposite type. This type of behavior makes this alternative violation check more advantageous.

At this point, the second phase of the solution algorithm is completed. However, additional iterations between phases I and II may be necessary, since satisfying some fuel constraints may have caused violations in the observance of the optimal contract ordering. The process iterates between the two phases until the two objectives are met. Namely, to observe the optimal fuel contract utilization sequence, and to satisfy the applicable fuel constraints.

A special note is in place at this point. The fuel prices that are fed from the optimal contract sequence to the dispatch module, are real – as opposed to pseudo – fuel incremental prices. As Gibson *et al.* pointed out [36], incremental prices, i.e., the price to pay for the next available unit of resources, are the appropriate prices for dispatch calculations. So, whereas updating the Lagrangian multipliers is the process to satisfy the problem constraints, updating the fuel prices enforces an optimally ordered fuel price schedule and thus guarantees an optimal and consistent dispatch schedule.

3.5.1 Implementation Considerations

Caution must be exercised while updating the multipliers. The bisection method was chosen in our implementation of the proposed algorithm; other search schemes may be used as well. If multipliers are overadjusted, cycling may occur. Fixing the price of the corresponding fuel at the midpoint level between the two cycling extremes for a number of iterations, appears to take care of cycling problems. Cycling may also occur as a result of very uneven price schedules of the various optimal fuel consumption orderings. To achieve convergence cycling prices need to be fixed at the midpoint of the cycling range, for a number of iterations.

If multiple fuel limits of different time horizons are to be simultaneously imposed, they may need to be prorated to fit the dispatching time horizon. Clearly, this is not a concern if the period of time associated with the fuel limits is smaller than the simulation horizon.

Production costing is based on fuel consumption per fuel group and operating costs are accurate when calculated for the entire simulation horizon.

Subsequently, prorated hourly or per generating unit fuel costs can be calculated based on relative fuel consumption. Obviously, this is not a problem in the degenerate cases when the simulation horizon is a single time period and each fuel group consists of a single generating unit. The fuel cost calculations in the post solution production costing must consider i) the order in which fuel from various contracts is consumed, ii) the required block order within each contract, and iii) the actual fuel price associated with each fuel block.

3.6 Numerical Results

3.6.1 Unconstrained Base Cases

The test system used consists of 50 generating units whose data are tabulated in the Appendix. Tables A1, A2, and A3 contain the fuel, NO_X, and SO_2 unit coefficients, Table A4 contains additional modeling parameters, and Table A5 presents the commitment schedule. The test system is divided in 12 power plants and 12 fuel groups whose configuration is shown in Table A6. The simulation horizon is 168 hours and Figure A1 shows the load profile. Load values are presented in Table A7. The necessary software programs were developed in FORTRAN and all test cases were executed on a HP Pentium at 166 Mhz. Table 3.3 shows detailed output results from dispatching the system economically.

Using objective functions that model quantities other than cost, results in different types of dispatches. Instead of Equation (3.3), which is the objective function for economic dispatch, minimum NO_X dispatch minimizes total system NO_X emission and its objective function is given by

$$\text{minimize} \qquad \sum_{i=1}^{G}\sum_{j=1}^{H} N_{i,j} \qquad \text{(Eq. 3.14)}$$

Minimum SO_2 dispatch minimizes total system SO_2 emission and its objective function is given by

$$\text{minimize} \qquad \sum_{i=1}^{G}\sum_{j=1}^{H} S_{i,j} \qquad \text{(Eq. 3.15)}$$

Models for $N_{i,j}$ and $S_{i,j}$ are presented in the next chapter. Minimum fuel dispatch minimizes total system fuel use and its objective function is given by

$$\text{minimize} \qquad \sum_{i=1}^{G}\sum_{j=1}^{H} F_{i,j} \qquad \text{(Eq. 3.16)}$$

The above types of dispatching are subject to the usual dispatch constraints, given by Equations (3.4)–(3.6). Since they are subject to no additional constraints, these dispatch cases are considered unconstrained base cases. They were used to define reasonable limits for the constrained cases that are presented in later chapters of this document, as well as to provide a basis of comparison with results from constrained dispatches. Results from these base cases are summarized in Table 3.4.

3.6.2 Fuel-Constrained Cases

The unconstrained base cases of the previous section used the fuel prices of Table A4 in the dispatching calculations. In the remainder of this chapter, the system is partitioned in 12 fuel groups, each group having access to different fuel supplies. Groups 1, 2, 3, and 12 have access to single price fuel supplies, whereas groups 5, 6, and 8 have access to single contracts. Each of the remaining fuel groups, i.e., 4, 7, 9, 10, and 11, has access to multiple fuel contracts, which are ordered according to the optimal consumption sequence described previously. Fuel group 4 has access to the fuel blocks shown in Table 3.1 and are optimally ordered in Table 3.2. Fuel input data for the remaining fuel groups are shown in Tables 3.5–3.7.

Four different test cases were run to demonstrate the characteristics of the fuel constrained dispatch. The first case is a dispatch with no take-or-pay requirements or over-the-limit constraints. The difference between this dispatch and the economic dispatch, whose results appear in Table 3.3, is the set of fuel prices used, as explained in the previous paragraph. This difference is reflected in the resulting system total costs. The second case enforces a take-or-pay requirement, the third case enforces an over-the-limit constraint, and the fourth case enforces both constraints simultaneously. The test cases are summarized in Table 3.8. Output results are summarized in Table 3.9 and detailed results from the fourth case are shown in Table 3.10. The first two rows of Table 3.9 present system results from the economic and minimum fuel dispatch base cases, for comparison reasons. As the results clearly demonstrate, the constraints are satisfied within the desired tolerance while the optimal fuel ordering for each fuel group is observed. It is interesting to note how the system total costs increase the more fuel constraints are applied.

3.7 Chapter Summary

This chapter discussed the fuel-constrained dispatch problem. Power producers have access to multiple fuel contracts, each one usually consisting of multiple fuel blocks with escalating price profiles. An optimization procedure was presented, which orders multiple fuel contracts with multiple fuel blocks in optimal consumption sequence. Take-or-pay contractual agreements and over-the-limit fuel constraints were discussed. The presented fuel-constrained dispatch accounts for these issues. A number of test cases were run and their results are summarized, to demonstrate the characteristics of the fuel constrained dispatch algorithm.

Table 3.3 Economic Dispatch Output Results

	Power	Fuel	Cost	SO_2	NO_X
			Unit Results		
1	3000.00	37690.19	48771.10	17.644	17.998
2	3047.12	38494.96	49812.38	20.874	18.152
3	3004.38	38223.82	49461.74	8.726	18.604
4	6549.58	73867.08	92186.16	26.032	31.091
5	4552.67	51209.27	63909.38	17.521	29.975
6	20805.32	187897.38	234495.95	73.219	43.843
7	10290.12	105363.19	131493.16	37.064	28.813
8	3016.47	36257.80	47388.98	19.871	15.308
9	16790.48	158334.50	206943.23	37.900	17.780
10	14386.64	136970.77	179021.00	53.896	14.778
11	15314.91	147569.59	194939.70	38.648	20.290
12	15754.90	153003.08	202116.70	39.308	20.825
13	23007.26	214102.80	282829.72	56.002	21.266
14	22762.39	214307.64	283100.47	54.974	20.994
15	45575.77	393568.22	519903.78	190.144	84.549
16	44125.85	379127.22	500826.88	184.808	79.555
17	3005.18	36233.93	48336.00	10.529	15.291
18	6096.30	62220.67	83002.39	20.216	31.148
19	5533.90	57959.68	77318.15	22.846	24.291
20	5977.71	60503.78	80712.03	22.662	24.833
21	2166.26	26254.35	33553.05	6.873	6.665
22	5373.49	60723.64	77604.79	22.595	28.637
23	6464.02	70976.45	90707.82	27.295	29.745

Table 3.3 (continued)

	Power	Fuel	Cost	SO_2	NO_X
24	16844.58	163144.69	208498.73	67.536	85.211
25	7518.19	89341.25	114178.11	31.727	22.487
26	54105.59	470854.06	601751.25	192.865	107.008
27	4532.50	47130.85	60091.86	16.682	16.107
28	12000.91	126883.72	161777.14	48.390	23.465
29	15460.48	155824.17	198675.61	42.341	10.866
30	16417.11	167295.73	213302.09	40.749	12.246
31	11783.58	128024.85	173345.97	31.135	6.602
32	11345.45	125856.41	170409.70	29.599	6.522
33	29410.68	264078.78	357563.13	154.830	54.468
34	33959.68	304915.63	412855.16	178.334	64.517
35	3946.76	42599.86	55166.81	8.676	8.064
36	3910.23	42870.83	55517.68	8.436	8.423
37	960.00	14628.55	18943.98	4.190	5.479
38	2160.00	25296.10	32758.42	6.503	7.171
39	2539.66	30276.61	37391.62	6.621	13.755
40	2510.68	30113.52	37190.18	6.867	14.817
41	3911.57	45199.14	55820.98	12.187	7.767
42	3455.44	40585.63	50123.21	10.749	7.121
43	13050.68	144904.19	193592.44	53.769	26.212
44	21122.74	188487.08	251818.77	62.560	46.597
45	49903.21	410242.53	548083.94	254.262	103.640
46	58189.98	450799.00	602267.31	297.152	119.307
47	11189.72	108645.44	146997.06	40.467	46.836
48	12473.09	119349.71	161480.25	48.179	47.736

Table 3.3 (continued)

	Power	Fuel	Cost	SO_2	NO_X
49	15569.66	143840.16	194615.86	63.355	15.894
50	15246.66	151829.59	205424.92	60.844	15.626
			Fuel Group Results		
1	9051.50	114408.95	148045.22	47.243	54.754
2	42197.68	418336.91	522084.66	153.835	133.722
3	34193.59	331563.06	433353.22	111.667	47.866
4	166541.09	1501678.63	1983717.25	563.885	247.478
5	20613.10	216918.06	289368.56	76.253	95.563
6	92472.13	881294.44	1126293.75	348.891	279.753
7	48411.00	497134.50	633846.75	148.161	62.684
8	86499.39	822875.69	1114174.00	393.898	132.110
9	10976.99	125395.33	162386.91	27.805	29.137
10	12417.34	146174.91	180526.00	36.424	43.460
11	142266.61	1194432.75	1595762.50	667.742	295.756
12	54479.13	523664.91	708518.13	212.845	126.093
			System Results		
	720119.56	6773877.50	8898077.00	2788.650	1548.375

Table 3.4 Output Results from Unconstrained Base Case Dispatches

Dispatch	Power	Fuel	Cost	SO_2	NO_X
economic	720,119.56	6,773,877.50	8,898,077.00	2,788.650	1,548.375
min NO_X	720,119.20	7,038,215.00	9,225,414.00	2,709.353	1,329.177
min SO_2	720,119.20	7,068,135.00	9,263,622.00	2,474.466	1,557.807
min fuel	720,119.31	6,767,508.50	8,905,795.00	2,803.833	1,543.787

Table 3.5 Input Fuel Data for Fuel Groups 1, 2, 3, and 12

Fuel Group	Maximum Available	Fuel Price
1	250,000	1.294
2	450,000	1.248
3	450,000	1.307
12	1,000,000	1.353

Table 3.6 Input Fuel Data for Fuel Groups 5, 6, and 8

Fuel Group 5		Fuel Group 6		Fuel Group 8	
Quantity	Price	Quantity	Price	Quantity	Price
95,000	1.422	225,000	1.440	70,000	1.471
170,000	1.349	450,000	1.398	185,000	1.418
210,000	1.334	675,000	1.372	275,000	1.326
265,000	1.275	900,000	1.275	395,000	1.273
300,000	1.246	1,125,000	1.246	500,000	1.237
		1,315,000	1.228		
		1,500,000	1.115		

Table 3.7 Input Fuel Data for Fuel Groups 7, 9, 10, and 11

Fuel Group 7		Fuel Group 9		Fuel Group 10		Fuel Group 11	
Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price
50,000	1.417	30,000	1.406	275,000	1.255	25,000	1.447
87,838	1.311	51,923	1.343	350,000	1.208	75,000	1.406
125,000	1.274	79,688	1.317	370,526	1.263	150,000	1.288
225,000	1.160	135,000	1.189	375,000	1.244	244,643	1.204
365,000	1.110	210,000	1.141	400,000	1.263	250,000	1.176
415,000	1.417	216,497	1.425			275,000	1.447
480,000	1.311	240,000	1.131			325,000	1.406
560,000	1.203	270,000	1.406			400,000	1.288
660,000	1.127	315,000	1.343			500,000	1.204
699,121	1.440	375,000	1.189			561,411	1.472
705,000	1.150	450,000	1.141			750,000	1.185
745,429	1.417	490,000	1.449			770,994	1.497
759,718	1.382	540,000	1.314			775,000	1.185
788,563	1.311	600,000	1.262			825,000	1.406
875,000	1.231	675,000	1.189			900,000	1.288
1,000,000	1.150					994,643	1.204
						1,000,000	1.176
						1,025,000	1.447
						1,075,000	1.406
						1,150,000	1.288
						1,350,000	1.204

Table 3.8 Fuel-Constrained Dispatch Test Cases

Case	Fuel Group	Minimum	Maximum
1	no take-or-pay or over-the-limit constraints		
2	10	275,000	
3	9		675,000
4	9, 10	275,000	675,000

Table 3.9 Summary of System Output Results from Fuel-Constrained Test Cases

Case	Power	Fuel	Cost	SO_2	NO_X
economic[1]	720,119.56	6,773,877.5	8,898,077.0	2,788.650	1,548.375
min fuel[1]	720,119.31	6,767,508.5	8,905,795.0	2,803.833	1,543.787
1	720,119.44	6,777,571.5	8,857,404.0	2,829.886	1,562.456
2	720,119.50	6,778,204.5	8,880,673.0	2,830.225	1,562.277
3	720,119.44	6,775,485.0	8,858,618.0	2,816.739	1,557.378
4	720,119.56	6,776,144.0	8,881,828.0	2,817.252	1,557.269

[1] base case results for comparison reasons only

Table 3.10 Output Results from Test Case 4

	Power	Fuel	Cost	SO_2	NOx
			Unit Results		
1	3000.000	37690.188	147428.56	17.644	17.998
2	3002.615	38061.910	148882.59	20.782	18.101
3	3000.000	38180.336	149345.82	8.717	18.599
4	5540.957	64607.910	720722.81	22.540	30.331
5	4500.958	50686.344	565423.06	17.343	29.935
6	16639.168	151619.531	1691366.50	58.808	38.145
7	6915.236	73305.219	817744.18	25.970	24.187
8	3000.000	36098.117	339186.62	19.842	15.283
9	13341.177	129168.734	1213700.63	31.509	13.439
10	11168.024	109217.977	1026238.50	46.184	11.065
11	16607.605	159258.781	5029298.00	41.668	22.252
12	17031.723	164513.734	5195246.00	42.322	22.831
13	23580.197	219407.125	6928747.00	57.469	22.437
14	23352.209	219756.219	6939771.00	56.484	22.191
15	46055.336	397902.500	12565525.00	192.086	86.287
16	44689.188	384305.406	12136137.00	187.294	81.792
17	3023.442	36409.395	214359.45	10.574	15.319
18	6035.426	61779.902	363727.71	20.095	30.861
19	5546.266	58109.121	342116.09	22.982	24.320
20	5983.644	60595.441	356754.25	22.786	24.843
21	2160.000	26191.869	192494.23	6.856	6.654
22	5270.145	59719.828	438904.21	22.419	28.546
23	5680.278	63743.980	468479.28	25.740	29.056

Table 3.10 (continued)

	Power	Fuel	Cost	SO_2	NO_X
24	15159.972	149471.047	1098520.88	60.735	73.244
25	7500.000	89159.000	655264.12	31.692	22.426
26	47820.094	417742.438	3070151.50	173.170	88.012
27	4828.469	49912.648	433539.00	17.889	17.287
28	12024.441	127123.500	1104189.00	48.477	23.510
29	16332.491	164103.672	1425397.13	44.554	12.566
30	17064.527	173324.719	1505490.63	42.426	13.320
31	11551.672	125931.063	1234790.50	30.584	6.356
32	11293.133	125367.953	1229269.13	29.478	6.461
33	34869.137	311855.375	2036400.75	181.187	65.835
34	40692.938	363153.656	2371376.00	211.578	81.600
35	4034.843	43412.195	146149.11	9.113	8.576
36	4016.093	43848.633	147618.41	8.933	9.076
37	960.000	14628.547	49247.66	4.190	5.479
38	2194.230	25649.605	86350.55	6.594	7.236
39	2576.156	30648.223	103178.62	6.744	13.788
40	2552.663	30540.137	102814.75	7.000	14.855
41	3901.266	45128.406	151926.81	12.171	7.797
42	3508.144	41121.273	138436.62	10.933	7.191
43	15301.605	166034.656	1728797.25	62.401	30.391
44	25848.684	229084.609	2385290.25	75.769	54.297
45	54292.684	446069.031	4644590.00	274.617	114.297
46	58214.988	450979.500	4695719.00	297.279	119.360
47	9944.100	98006.625	380063.28	36.771	45.479
48	11072.371	107624.352	417360.18	42.918	46.189

Table 3.10 (continued)

	Power	Fuel	Cost	SO_2	NO_X
49	14032.854	130716.633	506910.56	57.931	14.974
50	13408.391	135177.531	524209.62	54.013	13.195
Fuel Group Results					
1	9002.615	113932.430	147428.56	47.142	54.698
2	33596.316	340219.000	424593.31	124.660	122.598
3	27509.201	274484.813	358751.65	97.534	39.787
4	171316.250	1545143.750	2040279.50	577.322	257.790
5	20588.777	216893.859	298414.65	76.436	95.343
6	83590.484	806028.125	1114310.88	320.611	247.938
7	50249.930	514464.531	636725.81	153.345	66.682
8	22844.805	251299.016	353952.50	60.061	12.817
9	75562.078	675009.000	843465.68	392.765	147.436
10	23743.396	274977.031	367715.00	65.677	73.998
11	153657.953	1292167.750	1658245.00	710.066	318.345
12	48457.715	471525.125	637973.50	191.632	119.838
System Results					
	720119.563	6776144.000	8881855.75	2817.252	1557.269

4. EMISSION-CONSTRAINED DISPATCH

This chapter addresses the dispatch problem when environmental limitations are imposed. The first section of the chapter provides a comprehensive literature review. The second section presents the formulation of the minimum emission dispatch problem. The third section addresses the emission constrained dispatch problem and the fourth section discusses a proposed approach to solve it. The fifth section presents numerical results. The final section provides a chapter summary.

4.1 Literature Review

Emission dispatching strategies first appeared in the relevant literature in the 1970's. Those strategies can be divided into two broad categories: i) methods minimizing emissions [43,44], and ii) methods minimizing cost subject to emission constraints [45,46,47,48]. In other words, emission constraints may appear either in the objective function after being monetized through appropriate conversion factors, or in the constraining set. Reference [49] provides a good review of the emission related literature of the 1970's and the 1980's.

Passage of the 1990 CAAA renewed interest in emission dispatch and a new set of literature emerged. Talaq *et al.* [50,51] presented the minimum emission power flow. Emission constraints were incorporated in the conventional OPF formulation and the objective function included operating and emission costs in a multiobjective optimization formulation. The tradeoffs between the objectives were also studied. Sensitivity analysis was applied to the results of the minimum emission power flow. The analysis included the effects on the problem variables and the optimal solution from variations of parameters, such as system demand, emission limits, weighting factors, etc. Emission constraints in OPF is one of the topics treated in the paper by Ramanathan [52]. Additionally, a weighted dual objective approach is presented to solve the emission-constrained problem. The same author presented four additional simple approaches to the same problem [53]. Each individual method had its own merits and disadvantages. The incremental analysis deemed useful for initial transaction selection, in a scenario where energy transactions were considered. The graphical analysis was applicable only on special cases, whereas the Taylor series analysis and emission constrained dispatching were suitable for exact calculations. Nanda *et al.* [54] presented the economic emission load dispatch problem. The objective function was modeled as a decision making problem, i.e., a compromise was sought between generation and pollution costs. A Gauss-Seidel variant was applied on the resultant coordinating equations and results were presented with and without line flow limitations. In their paper, El-Kaib *et al.* [55] presented a general formulation of the environmentally-constrained economic dispatch. The underutilization provision of the CAAA was modeled as additional fuel burn constraints. The Lagrangian relaxation method was used to solve the problem using a Newton-Raphson variant to solve the resulting set of linear equations. The effects of the extra burn constraints were investigated and two alternative dispatching strategies were discussed: i) the compensating unit option, and ii) the compensating unit designation option. Lamont *et al.* [56] presented a strategy to solve the emission-constrained dispatch problem, based on the ratio of incremental emissions over incremental costs, together with a discussion of startup emission models. Comparing the values of the ratio of the incremental quantities with the allowance market prices, provided insight on the profitability of increased allowance market involvement. Rau *et al.*, in their paper [57], followed similar concepts to develop operating strategies under emission constraints. Although they used the ratio of incremental costs over incremental emissions, they essentially arrived at similar conclusions as the previous approach. Augmented Lagrangian relaxation was used by Wang *et al.* [58] in their formulation. The Lagrangian of the problem was augmented by quadratic penalty functions. A decomposition and coordination technique was used to solve the optimization problem and the non-separable penalty terms were iteratively linearized around a suboptimal initial solution. A hierarchical structure was presented in the paper by Hu *et al.* [59], which used coordination between the off- and on-line subsystems to minimize a weighted average of the generation and emission costs. A cutoff point of relative cost increase versus relative emission decrease was defined and used as the ultimate termination parameter. The solution process might possibly be halted at an infeasible solution point with emission requirements not yet satisfied, if further emission reduction was deemed economically unprofitable. Emission and generation costs were jointly included in the objective function of the multiobjective formulation presented by Chen *et al.* [60] and by Wong *et al.* [61]. In the former approach, a fast Newton-Raphson scheme using a modified Jacobian matrix was proposed to solve the overall problem. In the latter approach, simulated annealing was the solution method used. In both approaches, a weighting equation linearly combined the emission and the generation costs to form a single objective function. However, one of the main problems in several of the above mentioned approaches was how to monetize emissions in order for emissions to be expressed in monetary units and thus, be included in the objective function. The use of emission allowances may provide indications for the magnitude of the conversion factors to be used.

The optimal dispatch problem including environmental constraints was also solved by means of goal programming [62], linear programming [63], and dynamic programming techniques [64]. The same problem was also formulated and solved through stochastic programming methods [65]. In [66], an IEEE operating problems working group report, various utility personnel reported on the actions taken and strategies followed by their respective companies to comply with the legislative requirements. Interestingly, a strategy potentially suitable for one company, might be completely inappropriate for a different company. Finally, the review papers by Talaq *et al.* [67] and Kazibwe [68] provided good summaries of most of the classical optimization approaches taken to solve the emission-constrained dispatch problem so far.

Although the emission dispatch problem has been successfully solved by many classical nonlinear optimization schemes, the biggest concern is that most of the presented methods can not be applied to real-time operation because of the long execution time requirements. Thus, fast computational times during the implementation phase have become of increased importance.

The same problem has been treated by many nonclassical optimization algorithms. King *et al.* [69] proposed a neural network model to solve the problem. A Hopfield neural network model was adopted and the solution sensitivity with respect to variations of the model parameters was analyzed. The Hopfield model is a single layer recursive neural network, in which the output of each neuron is connected to the input of every other neuron. There is also an additional external input connection to each neuron. Selection of the network parameters was of extreme importance to the solution optimality. A special technique, called momentum, was used to improve the convergence rates. An evolutionary algorithm, coupled with heuristics, was used in [70] to solve the emission dispatch problem. In brief, evolutionary algorithms are a family of stochastic, iterative algorithms based on the concept of evolution. Heuristics are often necessary to improve computational times. Stochastic operations, such as mutation, recombination, reproduction, and selection, are used to ensure evolution. Genetic algorithms belong to this family of optimization schemes. In the approach presented, a multiobjective function was optimized and tradeoff curves between costs and emissions were generated and analyzed.

Reference [71] used an interactive search to achieve simultaneous satisfaction of both NO_X and SO_2 emission limits. It was recognized that careful coordination between successively constraining each pollutant was necessary because of the often competing objectives of reducing NO_X and SO_2. The objective function used included the generation costs augmented with the emission constraints through the use of emission dispatch prices. The basic solution approach included three stages: i) the feasibility check phase, ii) the price identification phase, and iii) the price refinement phase.

Chattopadhyay [72] presented a brokerage system that performed emission allowance trading as well as energy transactions. The model was solved with linear programming methods. Cost savings, realized from trading, were allocated to participants according to a Shapley value based model. Although emission constraints did not formally enter the objective function, trading optimally allocated emission allowances so that all environmental requirements were satisfied. In a relevant paper, Walsh *et al.* [13] discussed some of the reasons for the slow development of a full speed allowance market. These reasons included a lack of widespread understanding of the trading process, emission compliance plan time structure, and the still regulated nature of the utility industry. Deficiencies of the present auctioning system were presented and alternative schemes were discussed. The paper indicated that, despite the few problems, overall, the emission trading program was a very positive experience.

The emission-constrained dispatch problem has attracted views and opinions from people outside the electrical engineering field. Relevant literature has appeared in management, economics, public policy, and operations research journals. Reference [73] discussed the integration of pollution control strategies, using linear models, to meet European emission standards. Cost effectiveness of the various scenarios was analyzed and the case of the then Federal Republic of Germany was presented as a test case. Petrovic *et al.* [74] discussed the operations research aspects of the environmental power dispatch, both as a single and as a multiobjective optimization problem. The paper could serve as a good background review and provided a list of interesting references dealing with the problem outside the United States.

Emission compliance can be also viewed as part of a long-term integrated resource planning process. References [75,76,77,78] are representative papers considering the emission problem in that context.

Finally, the emission-constrained scheduling problem may be also considered as a constraint satisfaction optimization problem [79]. Constraint satisfaction is a rather recently developed research area whose scope practically includes all problems studied in operations research. Constraint satisfaction introduces formal search techniques, but it also employs problem dependent heuristics. This approach has not been formally applied to the emission dispatching problem yet. However, constraint satisfaction is fast gaining popularity and it may provide potentially powerful alternative solution approaches to scheduling problems.

4.2 Minimum Emission Dispatch

4.2.1 Emission Modeling

The SO_2 and NO_X emissions produced by each generating unit are, in general, functions of the unit's power output. Just like in the fuel input modeling case, discussed in section 3.2.1, several mathematical functions are potential candidates to model emission output. For reasons similar to the ones discussed in that section, the reduced cubic formulation was chosen to model unit emission output. SO_2 emission output of the i^{th} unit during the j^{th} time period (hour) is given by

$$S_{i,j} = s_{i,a} + s_{i,b}P_{i,j} + s_{i,d}P_{i,j}^3 \qquad \text{(Eq. 4.1)}$$

NO_X emission output is given by

$$N_{i,j} = n_{i,a} + n_{i,b}P_{i,j} + n_{i,d}P_{i,j}^3 \qquad \text{(Eq. 4.2)}$$

In general, unit emission output is given by

$$E_{i,j} = e_{i,a} + e_{i,b}P_{i,j} + e_{i,d}P_{i,j}^3 \qquad \text{(Eq. 4.3)}$$

4.2.2 Problem Formulation

The objective of minimum emission dispatch is to minimize the total emissions, which are the sum of individual unit emission output taken over all units operating within the system over the dispatch period. In some planning applications, multiple periods are involved, which was the case considered during this research work, and the goal is to minimize the total emissions over the entire set of time periods. If no change in commitment pattern is considered, the objective is given by

$$\textit{minimize} \qquad \sum_{i=1}^{G}\sum_{j=1}^{H} E_{i,j} \qquad \text{(Eq. 4.4)}$$

Using the reduced cubic formulation, the second derivative of the unit emissions is positive over the entire range of power output values; thus, the objective function is a convex function.

The remaining constraints of this type of dispatch are the same as in the economic dispatch problem. Namely, each generating unit on automatic control must be operated within its minimum and maximum power output limits (Equation 3.4) and the total generation for a lossless, islanded system must exactly match the forecasted system load for each hour (Equation 3.5). Equation 4.1 together with Equations (3.4)–(3.5) provide the mathematical formulation of the minimum emission dispatch problem.

4.3 Dispatching with Emission Limits

4.3.1 Emission Constraints

Even though total system or company emissions over the entire simulation period are the most common emission constraint, it may be necessary or desirable to consider smaller periods of time, or subsets of generating units. The following four types of emission constraints were considered during this research:

1) System emission limit over the entire simulation horizon.

2) Plant emission limit(s) over the entire simulation horizon.

3) System emission limit(s) for single time period(s).

4) Plant emission limit(s) for single time period(s).

The above types of emission constraints are prioritized in the above order with respect to their significance to the total system operation. Special circumstances, however, may exist, in which the above ordering needs to be modified (e.g., geographically localized heavy pollution). This formulation was made at the plant level. However, it could be easily expanded to the unit level.

4.3.2 Problem Formulation

The objective function to be minimized is the total operating costs, the same quantity as in the economic dispatch problem. In addition to the imposed emission constraints, the usual dispatch constraints must be satisfied, i.e., each unit must be operated between its limits and the total generation in each hour must exactly match the generation requirements defined in Equation 3.6. The emission-constrained dispatch problem is mathematically formulated as follows:

$$\textit{minimize} \qquad \sum_{i=1}^{G}\sum_{j=1}^{H} C_{i,j} \qquad \text{(Eq. 4.5)}$$

where Equation 4.5 represents the system total operating costs,
subject to

$$P_i^{Mn} \leq P_{i,j} \leq P_i^{Mx} \qquad \text{(Eq. 4.6)}$$

where Equation 4.6 represents the power output limits of the individual generating units

$$\sum_{i=1}^{G} P_{i,j} = P_j^R \qquad \text{(Eq. 4.7)}$$

where Equation 4.7 represents the fact that the total generation in each hour should exactly equal the power requirements during that hour

$$\sum_{i=1}^{G}\sum_{j=1}^{H} E_{i,j} \leq E_{A,T}^{Mx} \qquad \text{(Eq. 4.8)}$$

where Equation 4.8 represents the emission limit for the power system for the entire simulation horizon (type 1 of emission constraints)

$$\sum_{j=1}^{H} E_{p,j} \leq E_{p,T}^{Mx} \qquad \text{(Eq. 4.9)}$$

where Equation 4.9 represents the emission limit for plant p for the entire simulation horizon (type 2 of emission constraints)

$$\sum_{i=1}^{G} E_{i,j} \leq E_{A,j}^{Mx} \qquad \text{(Eq. 4.10)}$$

where Equation 4.10 represents the emission limit for the power system for hour j (type 3 of emission constraints)

$$E_{p,j} \leq E_{p,j}^{Mx} \qquad \text{(Eq. 4.11)}$$

where Equation 4.11 represents the emission limit for plant p for hour j (type 4 of emission constraints).

4.3.3 Objective Function Alternative Formulation

An alternative formulation of the problem objective function has been presented in some relevant literature [54,60], based on the mathematical models developed in goal programming [80]. The problem is modeled as a decision making process where a "compromise factor" must be found between emission, E, and generation costs, C. Such a compromise factor may be modeled by a weighting factor α and the objective function is given by

$$\textit{minimize} \qquad (1-\alpha)C+\alpha E \qquad \text{(Eq. 4.12)}$$

At the implementation stage, four types of weighting factors, α^1, α^2, α^3, and α^4, can be defined and associated with the four different types of emission constraints. The objective function is then given by

$$\textit{minimize} \qquad \sum_{i=1}^{G}\sum_{j=1}^{H} Z_1[(1-\alpha^1),(1-\alpha^2),(1-\alpha^3),(1-\alpha^4)]C_{i,j} +$$

$$\sum_{i=1}^{G}\sum_{j=1}^{H} Z_2[\alpha^1,\alpha^2,\alpha^3,\alpha^4]E_{i,j} \qquad \text{(Eq. 4.13)}$$

The values of all weighting factors and the values of Z_1 and Z_2 are between 0 and 1. α^1 is a single number, while α^2 and α^3 are vectors. The dimension of α^2 equals the number of power plants in the system, whereas that of α^3 equals the number of time periods in the simulation horizon. α^4 is a two-dimensional array whose dimensions are number of plants times number of time periods.

4.4 Solution Algorithm

The solution approach used consists of three phases and is shown in Figure 4.1. In the first phase, the solvability of a given problem is examined. The second phase calculates an initial set of Lagrangian multipliers (or weighting factors) that satisfy the given emission constraints. The third phase, if necessary, is an iterative readjustment of the weighting factors until all emission constraints are exactly matched and the dispatching constraints are satisfied.

Phase I – Feasibility check Although a useful tool, emission-constrained dispatching can achieve emission reductions up to the levels defined by minimum emission dispatching for each period and summing as appropriate. The feasibility check consists of running a minimum emission dispatch to determine whether the given emission limits are at all achievable by means of emission-constrained dispatching alone. If the required limits are below the levels attainable by minimum emission dispatching, the problem is deemed unsolvable and additional compliance measures need to be taken. The feasibility check is completed by running an economic dispatch to check whether the limits of a given problem fall below the economic dispatch emission levels. Clearly, if an economic dispatch satisfies the emission constraints, it is the optimal dispatch schedule and the problem is solved.

In the presence of multiple constraints of different types of pollutants, there is a "gray" area in the proximity of the lowest achievable emission levels. Any value within this area can be achieved if a single emission constraint is applied. If multiple constraints are simultaneously binding, some values may not

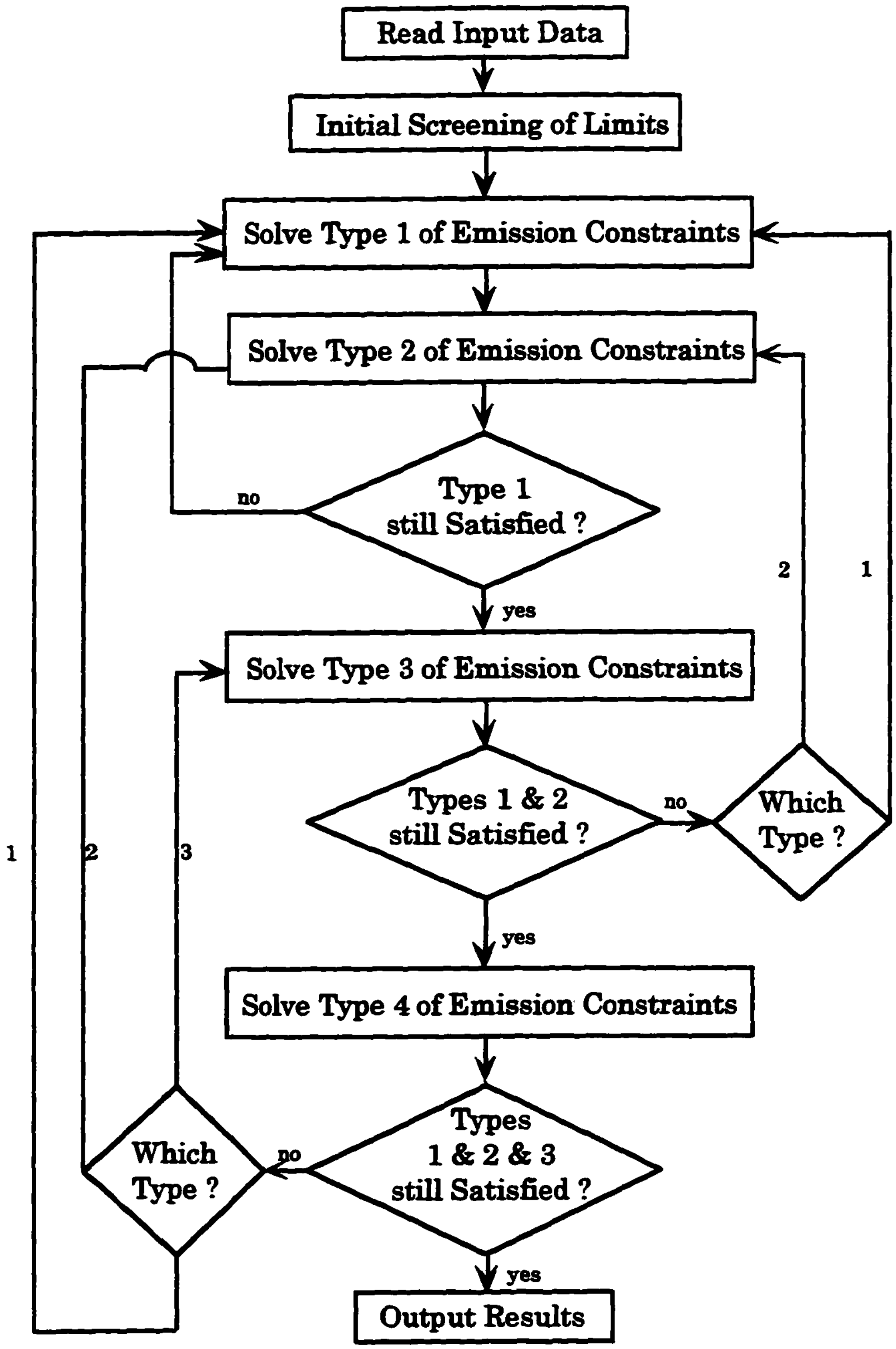

Figure 4.1 Emission-Constrained Dispatch Solution Flowchart for Single Pollutant

be finally attainable despite being so determined during the initial feasibility check. This is because attempting to satisfy multiple constraints often moves the optimal operating point towards different directions. This is especially true in the case of simultaneously constraining multiple pollutants, e.g., NO_X and SO_2.

Phase II – Calculating an initial set of the Lagrangian multipliers In order to simultaneously satisfy all applicable environmental constraints, a partitioning and coordination strategy was developed. The terms partitioning and decoupling are used interchangeably in the remainder of this chapter. The decoupling proceeds on two levels. At the first level, the problem is decoupled based on the different types of pollutants, so that at any time only the weighting factors of a single type of pollutant are being adjusted. At the second level, the already decoupled problem, is partitioned once again according to the four different types of emission constraints. The emission constraints are then satisfied in a sequential order that may be altered if special circumstances exist. The multiplier associated with the first type of emission constraints is found at first, using a single line search algorithm, such as bisection or secant search. Once this multiplier is found, the search continues with the multipliers associated with the second type of emission constraints. These are found again by means of single line searches. In the event of multiple constraints of the second type, this part of the search is an iterative process, since optimizing the output of a given plant to emit up to a specified target value, may affect the operation of other plants that may have already been treated. Using the updated multipliers, the process iterates until all constraints of the second type are satisfied. At this point, it is important to check whether meeting emission constraints of the second type has renewed or created a violation of the previous type, in which case it must be corrected. The next step is to satisfy the constraints of the third type. At the completion of this step, the search process once again checks to determine that constraints of previous types continue to be satisfied. Finally, the multipliers associated with the fourth type of emission constraints are calculated. As in the case of the constraints of the second type, this step may require several iterations if multiple constraints of this type are to be simultaneously met. The final step is to ensure that at this point all previously satisfied constraints continue to be within their respective target values. If any violations are detected, the search cycles to the appropriate level and the process iterates.

At the completion of the above search process, if a single pollutant is to be constrained, an optimal dispatch schedule has been found that satisfies all emission constraints. It is important to note at this point that, in general, oversatisfying emission constraints unnecessarily increases the total operating costs. So, it is preferable from an economic viewpoint to treat the mathematical inequalities describing the environmental constraints as equalities, and calculate multipliers to match emission outputs to the target values. However, there are exceptions to this strategy. For instance, satisfying exactly a broad (e.g., systemwide) constraint may cause overcomplying of a more narrow (e.g., plant-level) constraint that can not be improved without causing a violation of the broad constraint.

If additional types of pollutants are to be optimized, the above search process is repeated for the next type of pollutant and the appropriate set of multipliers is calculated, while holding constant, the previously adjusted multipliers for all other pollutants. Figure 4.2 presents the solution flowchart for that case.

Phase III – Refinement of the multipliers As already indicated, if a single pollutant is to be complied with, completion of phase II provides the optimal dispatch schedule. The refinement phase is performed every time the

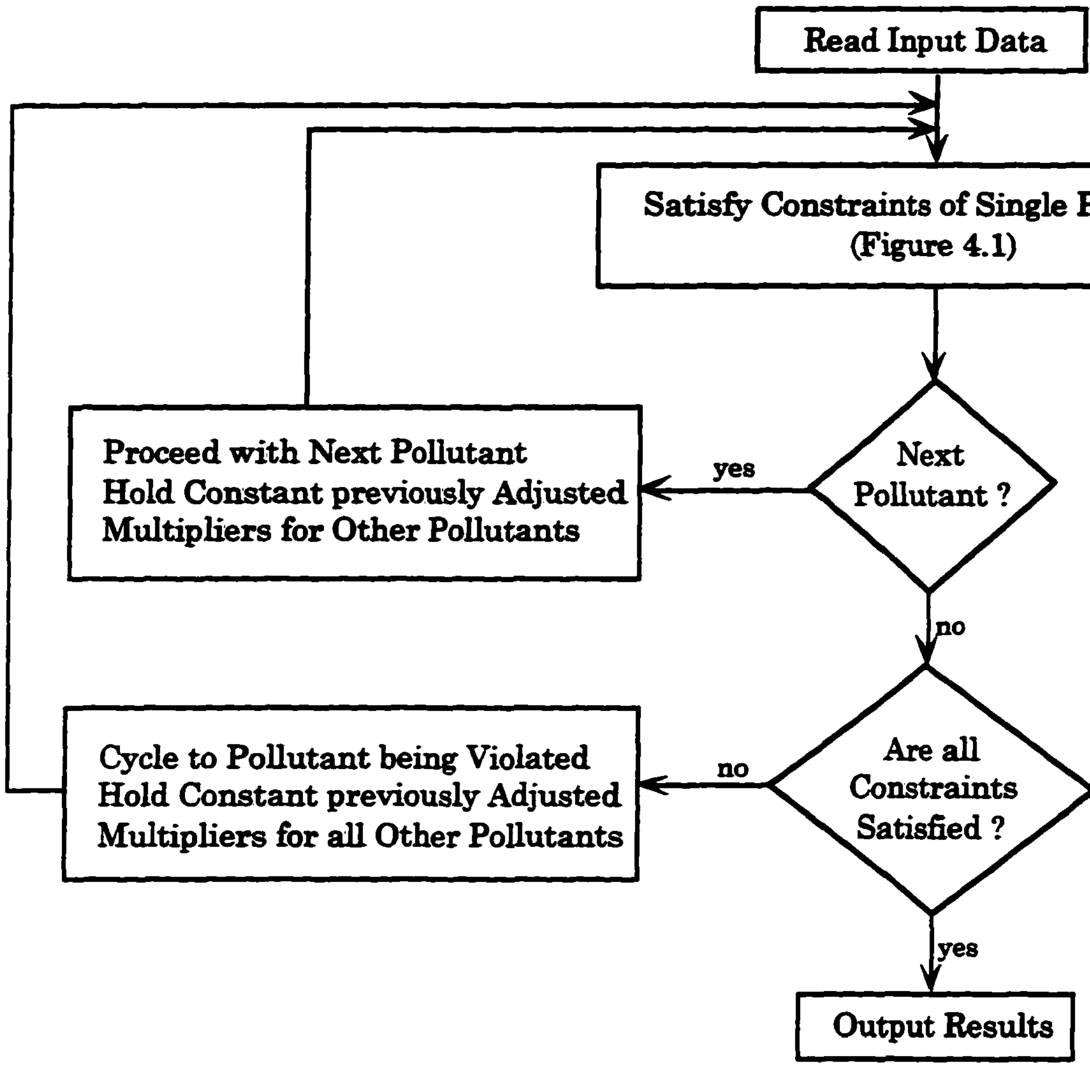

Figure 4.2 Emission-Constrained Dispatch Solution Flowchart for Multiple Pollutants

search process back-checks to ensure that constraints of previous types are still satisfied. However, in the event of multiple pollutants, completion of phase II provides a dispatch schedule that generally satisfies only the constraints of the last type of pollutant considered. It is important to recognize that simultaneous optimization of emissions of various pollutants adds another degree of complexity. This is because although all emissions are correlated to the fuel resources, oftentimes, decreasing emissions of one pollutant may cause an increase in the emissions of another pollutant. In such a case, once phase II is completed, phase III comes into play. Phase III consists of checking to see whether all emission constraints are met. If violations are detected, the search process repeats the second phase treating the violated constraints. The entire procedure iterates until all constraints are simultaneously satisfied, at which point the optimal dispatch schedule is produced.

<u>Partitioning and coordination</u> As already mentioned, the problem is partitioned twice: according to the type of pollutant and according to the four types of emission constraints. At any point during the solution process, a single type of emission constraint, of a single type of pollutant, is treated. Coordination is achieved through the use of the updated values of the multipliers. At all levels of the search process, all multipliers previously calculated are used to provide the current dispatch schedule. Calculation and refinement of the multipliers at the level of type of emission constraint is performed during phase II of the solution process. Refinement of the multipliers at the level of type of pollutant is performed at the third phase of the search. Refined versions of the search process may be developed by considering particular attributes of the detected violations, e.g., their relative magnitude. In all instances however, the basic structure presented in this section remains the same.

4.4.1 Similarities of the Proposed Algorithm with Other Approaches presented in the Literature

The proposed algorithm follows the partitioning and coordination principle, a common characteristic of all methods based on the successive relaxation of the Lagrangian multipliers. Reference [81] presents an extensive and thorough treatment of Lagrangian multipliers-based optimization schemes. References [38,82] discuss the application of Lagrangian relaxation on the unit commitment problem. A formal treatment of the Lagrangian relaxation method applied on the emission-constrained dispatch problem is presented in [83].

In reference [71], the complexities involved in the simultaneous optimization of NO_X and SO_2 emissions are pointed out. Single line searches are used to update the emission dispatch prices. The overall objectives of that approach present similarities to the objectives of the approach presented in this section, i.e., development of a solution scheme that can carefully coordinate emission reduction of various types of pollutants and can demonstrate fast execution times for possible on-line implementation. In the approach presented in this dissertation, an additional level of complexity exists by considering multiple types of emission constraints. At the implementation level, weighting factors were used that can take values between 0 and 1 instead of emission dispatch prices. Using such factors provides the additional benefit of readily knowing upper and lower bounds of the decision parameters during the single line searches. Moreover, whether a constraint is overshot or is not attainable can be easily determined by inspecting the values of the corresponding factor. The weighting factors of the final dispatch schedule can be scaled to provide optimal emission dispatch prices. Such prices, in the case of SO_2, provide indications on whether emission allowance trading may be profitable and should be pursued.

4.4.2 Implementation Considerations

The use of weighting factors that can take values between 0 and 1 provides a convenient way to determine whether a particular constraint is satisfiable or not. Weighting factors taking values in the neighborhood of 0 clearly put more weight on economic dispatch whereas values close to 1 signify heavy reliance on minimum emission dispatch. If a particular factor takes a value of 1 and the emission target is not yet achieved, it is likely that the constraint is unattainable. Conversely, a value of 0 means that the corresponding constraint is not binding. Although most of these extreme cases will be detected during the initial phase of the solution procedure, when several weighting factors have non-zero values and the corresponding constraints are active, the solution space is reduced and values initially deemed attainable may no longer be so.

It may be desirable to offer flexibility to the end user by providing the capability of an additional weighting factor that may control a block of units for a block of time periods. Additionally, there may exist cases where the order in which the different searches are executed should be altered. The necessary scaling of the weighting factors to provide emission dispatch prices should be carefully developed. These considerations should be taken into account during the development of the algorithm implementing the proposed solution approach.

4.5 Numerical Results

The algorithm presented in the previous sections was applied to the same 50 generating unit test system used to run the fuel-constrained dispatch test cases. The system data and the load profile are shown in the Appendix. The software programs were developed in FORTRAN and the test cases were executed on a HP Pentium at 166 MHz.

Ten different test cases were run and the results are summarized in the remainder of this section. The imposed emission limits for each case are shown in Table 4.1. Cases 1–4 impose an increasing number of NO_X constraints whereas cases 5–8 impose an increasing number of SO_2 limits. Case 9 simultaneously satisfies systemwide NO_X and SO_2 constraints. The last case applies simultaneously all possible types of constraints.

Figure 4.3 shows the increase in cost when a systemwide NO_X constraint is applied. Figure 4.4 presents a similar case for SO_2. Table 4.2 presents a summary of the numerical output results from cases 1–10. The first three rows of Table 4.2 present system results from the economic and minimum emission dispatch base cases, for comparison reasons. Because of their economic interpretation as emission shadow prices, the final values of the weighting factors – or Lagrangian multipliers – associated with the first type of emission constraints – systemwide, entire simulation horizon – are presented in Table 4.3. These values may provide insight on whether it would be profitable for power producers to get involved in emission allowance trading. Although to date, emission allowances have been introduced just for SO_2, the multipliers associated with the NO_X constraints are also included for consistency. Table 4.4 contains the complete results from execution of test case 10. In those instances in Table 4.2, where there is no difference in the output values before and after enforcing a constraint, the particular constraint has already been satisfied by enforcement of a broader constraint. All applied limits were achieved within required tolerance in very reasonable times. Execution of the most complete of the test cases, i.e., case 10, requires approximately 80 seconds. It should be emphasized however, that execution times depend not only on the number of constraints but also on how restrictive they are.

Table 4.1 Description of Emission-Constrained Test Cases

	Total Time NO_X		Hour 150 NO_X		Total Time SO_2		Hour 150 SO_2	
Case	System	Plant 11	System	Plant 11	System	Plant 11	System	Plant 11
1	1480							
2	1480	230						
3	1480	230	3.15					
4	1480	230	3.15	1.1				
5					2650			
6					2650	485		
7					2650	485	8.35	
8					2650	485	8.35	2.4
9	1480				2650			
10	1480	230	3.15	1.1	2650	485	8.35	2.4

4.6 Chapter Summary

The development and testing of an emission-constrained dispatch model was presented in this chapter. Four distinct classes of emission constraints were defined: i) systemwide, for entire simulation time, ii) plant-level, for entire simulation time, iii) systemwide, for single hour, and iv) plant-level, for single hour. The dispatch process may account for the worth of emission allowances. A Lagrangian multipliers variant is used to solve the problem, using single line searches to update the multipliers. A number of test cases were run and a summary of the numerical output was presented. The test cases demonstrate the characteristics and the capabilities of the emission-constrained dispatch algorithm.

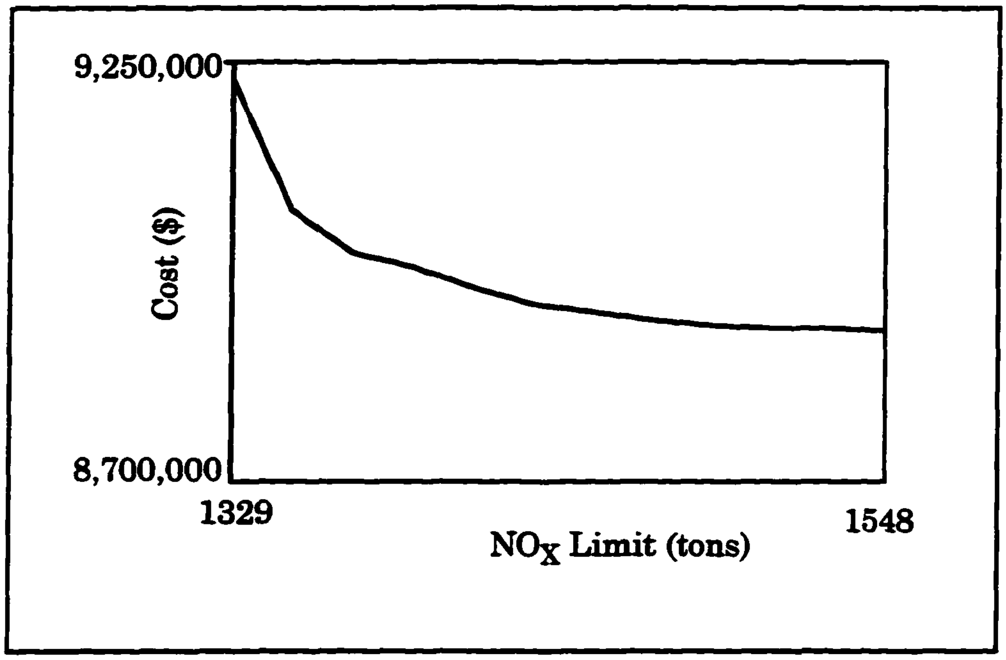

Figure 4.3 Cost versus Systemwide NO_X Limit

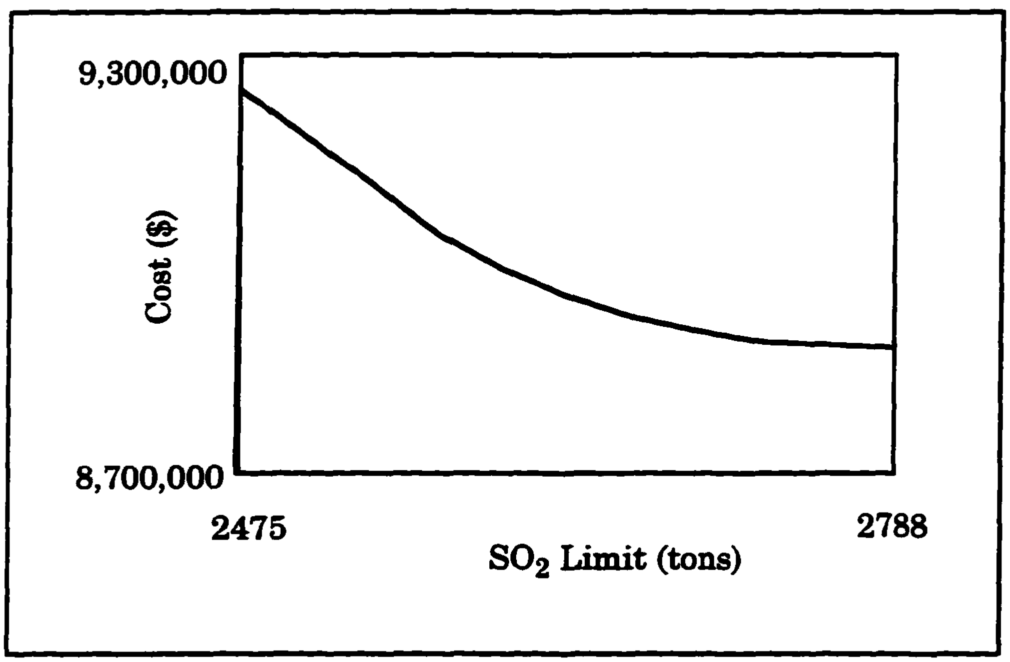

Figure 4.4 Cost versus Systemwide SO_2 Limit

Table 4.2 Summary of Output Results from Emission-Constrained Test Cases

Case	Power	Fuel	Cost	SO_2	NO_X
economic[1]	720,119.56	6,773,877.5	8,898,077.0	2,788.650	1,548.375
min NO_X[1]	720,119.20	7,038,215.0	9,225,414.0	2,709.353	1,329.177
min SO_2[1]	720,119.20	7,068,135.0	9,263,622.0	2,474.466	1,557.807
1	720,119.25	6,779,049.0	8,905,774.0	2,762.504	1,479.996
2	720,119.44	6,800,404.5	8,926,799.0	2,732.776	1,479.996
3	720,119.44	6,800,399.5	8,926,796.0	2,732.772	1,480.008
4	720,119.44	6,800,399.5	8,926,796.0	2,732.772	1,480.008
5	720,119.31	6,817,340.5	8,945,347.0	2,649.999	1,482.356
6	720,119.44	6,826,068.5	8,953,012.0	2,649.998	1,489.192
7	720,119.44	6,826,068.5	8,953,012.0	2,649.998	1,489.192
8	720,119.44	6,826,068.5	8,953,012.0	2,649.998	1,489.192
9	720,119.50	6,817,262.5	8,945,370.0	2,649.992	1,479.980
10	720,119.31	6,836,075.0	8,965,138.0	2,650.064	1,479.999

[1] base case results for comparison reasons only

Table 4.3 Final Values of Weighting Factors from Emission-Constrained Test Cases

Case	α^1 for NO_X	α^1 for SO_2
1	0.995798	
2	0.994947	
3	0.994944	
4	0.994944	
5		0.998536
6		0.998040
7		0.998040
8		0.998040
9	0.0197754	0.998498
10	0.161133	0.997053

Table 4.4 Output Results from Test Case 10

	Power	Fuel	Cost	SO_2	NO_X
			Unit Results		
1	3126.04	38978.27	50437.86	17.899	18.186
2	3527.26	43189.50	55887.14	21.891	18.766
3	3257.49	40763.60	52748.23	9.254	18.980
4	7040.49	78381.95	97820.72	27.732	31.462
5	4644.63	52142.00	65073.43	17.841	30.047
6	23136.94	208188.94	259819.89	81.284	47.027
7	12337.68	124827.38	155784.50	43.797	31.622
8	3364.42	39667.48	51845.47	20.497	15.918
9	21355.67	197999.20	258784.95	46.873	24.366
10	17684.95	165195.56	215910.58	61.488	18.399
11	24817.21	232685.88	307378.31	60.638	32.215
12	25197.35	237175.08	313308.34	60.388	32.604
13	29209.61	267080.00	352812.69	70.323	29.305
14	29121.94	268628.09	354857.72	69.335	29.162
15	44596.91	384538.38	507975.38	186.174	80.693
16	42626.16	365410.84	482707.75	178.217	73.723
17	3109.54	37238.61	49676.26	10.786	15.454
18	6296.72	63836.62	85158.06	20.728	32.116
19	6535.03	66865.52	89198.59	25.076	24.911
20	6988.13	69319.47	92472.13	24.851	25.625
21	2225.66	26847.80	34311.46	7.036	6.772
22	6227.89	69056.06	88253.65	24.135	29.390
23	7891.96	84168.20	107566.93	30.167	31.000

Table 4.4 (continued)

	Power	Fuel	Cost	SO_2	NO_X
24	14537.35	143952.48	183971.38	52.936	59.408
25	7879.73	92959.90	118802.77	32.398	23.639
26	55896.66	485473.44	620435.13	198.175	111.522
27	4287.57	44808.39	57130.71	15.666	15.050
28	12002.39	126898.67	161796.22	48.395	23.468
29	18867.84	187515.94	239082.73	50.373	15.863
30	19163.23	192199.08	245053.75	47.455	16.102
31	13206.19	140958.17	190857.63	34.584	8.242
32	12223.28	134085.09	181551.30	31.675	7.621
33	26487.63	239067.27	323697.66	140.955	49.247
34	29669.14	268388.59	363397.91	157.439	55.012
35	3853.74	41779.16	54103.98	8.233	7.545
36	3816.33	42035.01	54435.33	8.011	7.870
37	960.00	14628.55	18943.98	4.190	5.479
38	2166.54	25363.20	32845.31	6.519	7.181
39	2770.28	32558.21	40209.39	7.318	13.948
40	2815.00	33135.36	40922.14	7.693	15.094
41	4101.99	47018.16	58067.44	12.828	7.944
42	3619.73	42216.81	52137.74	11.286	7.273
43	12600.00	140756.78	188051.50	52.049	25.390
44	14322.41	131515.08	175703.75	44.274	35.721
45	23399.43	200971.50	268497.94	132.300	51.406
46	40591.89	324233.47	433176.34	209.189	84.317
47	12157.05	116911.06	158180.61	43.341	47.889
48	12751.47	121604.98	164531.61	49.220	48.041

Table 4.4 (continued)

	Power	Fuel	Cost	SO_2	NO_X
49	16265.37	149782.86	202656.23	65.811	16.312
50	15387.38	153073.59	207108.06	61.343	15.670
			Power Plant Results		
1	9910.79	122931.36	159073.22	49.044	55.932
2	47159.74	463540.25	578498.50	170.653	140.158
3	42405.05	402862.25	526541.00	128.859	58.684
4	195569.19	1755518.25	2319040.00	625.076	277.702
5	22929.43	237260.22	316505.03	81.441	98.106
6	94659.27	902457.88	1153341.25	344.847	261.732
7	54321.03	551422.06	703063.44	161.890	70.482
8	81586.25	782499.13	1059504.50	364.654	120.123
9	10796.61	123805.91	160328.59	26.952	28.075
10	13306.99	154928.55	191336.70	39.125	44.260
11	90913.73	797476.88	1065429.50	437.811	196.834
12	56561.27	541372.50	732476.50	219.714	127.912
			System Results		
	720119.31	6836075.00	8965138.00	2650.064	1479.999

5. FUEL- AND EMISSION-CONSTRAINED DISPATCH

The main purpose of this short chapter is to discuss the overall scheme that combines the two solution approaches presented in the two previous chapters. The first section of this chapter provides a literature review. The second one briefly discusses the overall solution approach and the coordination of the different modules, and the third section presents numerical results. A chapter summary section completes the chapter.

5.1 Literature Review

Only a few publications have addressed the combined fuel- and emission-constrained dispatch problem treating both subproblems equally. In most instances, one of the two components was addressed in varying form, from simple to complex, while the other component was modeled in a simple way.

Vickers *et al.* [84] used linear functions to model fuel and environmental constraints. The main focus of their approach was on the potential cost tradeoffs between emission allowances and sulfur content. The paper also discussed the changes that occurred in a rural electric cooperative's dispatching activities. The paper by Lee *et al.* [85] addressed a similar idea of optimally coordinating the consumption of take-or-pay fuel contracts with the emission allowance trading. The resulting problem was solved by a decomposition and coordination approach following the principles of Lagrangian relaxation. In another paper by the same principal authors [86], an adaptive simulation structure was presented for operational planning use under annual environmental and fuel constraints. The advantage of the algorithm they proposed was that it captured the chronological patterns of the power generation. Production simulation was performed sequentially for one week at a time and its results were used to define the target values for the remaining time periods. The uncertainty in unit availability was modeled by a conditional Monte Carlo-based sampling procedure. Finally, reference [87] summarized the discussions of an expert panel on efficiently coordinating resource allocations. Alternative coordination schemes were presented by different panel members, each with its own merits. Additional considerations besides fuel and emissions were also addressed, such as allowance markets, hydro scheduling, optimal generation mix, etc. The overall conclusion was that the required coordination could be achieved by manipulating either resource target values or resource dispatch prices.

5.2 Solving the Overall Problem

5.2.1 Combined Algorithm

This section indicates how the two dispatching strategies were combined into a single methodology. The combined fuel- and emission-constrained dispatch problem can be solved through a modular approach that combines the solution methods to the individual components. The two principal subproblems are solved iteratively and optimal dispatch schedules are communicated between them. The main building block is the generation dispatch process, common to both subproblems. The overall process iterates until i) all of the constraints are satisfied and an optimal solution is reached, or ii) some constraints are deemed unattainable through modified dispatching techniques and the process halts. Each individual subproblem is solved following the respective algorithms presented in the previous two chapters. Once an initial screening of the imposed constraints is performed, the combined problem presents an additional level of coordination and complexity. A schematic diagram of the coordination of the modules is shown in Figure 5.1.

5.2.2 Implementation Considerations

One of the advantages of the proposed approach is its simplicity and fast execution time compared to the limited number of other approaches reported in the literature, thus making it applicable for on-line implementation. Performance speed and execution times depend on a number of parameters, including system size, number of constraints imposed, tolerances used, etc. Since reasonable computational time limits are necessary, there are usually ways to improve the execution times, but they are generally case and/or system dependent. The most useful strategy is to explore potential correlations among the imposed constraints. In the fuel-constrained dispatch case, solving the over-the-limit consumption violations usually offsets some of the take-or-pay violations. On the emission side, satisfying systemwide constraints oftentimes simultaneously meets or exceeds target values for constraints applicable over smaller subsets of units.

Cycling may occur at any level of the optimization process. In most cases, the value of some weighting factor cycles between a maximum and a minimum values. If such a case is detected, the parameter responsible for it needs to be adjusted to appropriate levels for a number of iterations, usually at the midpoint of the cycling range. Nonetheless, all single dimensional searches should be well structured to avoid endless looping.

Linear programming techniques could have been used to solve the combined problem, provided that linear approximations would have been used to

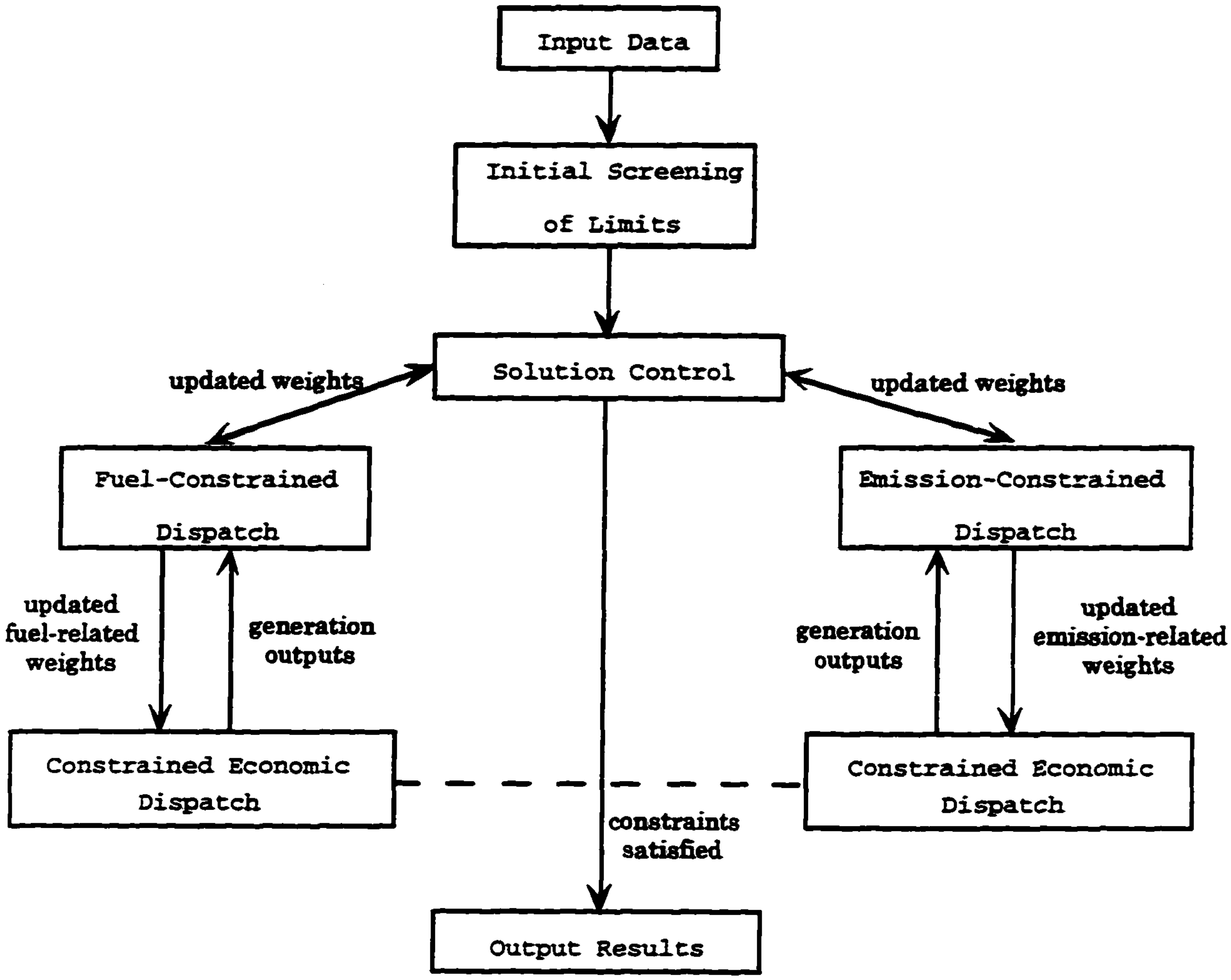

Figure 5.1 Fuel- and Emission-Constrained Dispatch

transform the actual data – available in reduced cubic form – into suitable piecewise linear models. It is possible that computational speed might improve and high accuracy could be achieved by using a sufficient number of linear segments to represent the cubic curves. However, linear programming methods were not tested; thus, there is no basis for comparison.

5.3 Numerical Results

The combined algorithm was applied to the same 50-unit test system used to run the fuel-constrained and the emission-constrained test cases. The test case presented in this section simultaneously satisfies the combination of case 4 of the fuel-constrained dispatch and case 10 of the emission-constrained dispatch. Moreover, each fuel group observes its optimal fuel consumption ordering. The numerical output shows results for individual units, power plants, fuel groups, and the entire system and is presented in Table 5.1. As the results indicate, some of the applied constraints are not binding. Enforcing the systemwide NO_X and SO_2 constraints simultaneously satisfies the take-or-pay requirements for fuel group 10 and there are no over-the-limit violations for any of the fuel groups. Cost calculations for individual units were performed during the post solution production costing process. The execution time was approximately 90 seconds on a HP Pentium at 166 MHz.

5.4 Chapter Summary

The combined fuel- and emission-constrained dispatch algorithm was presented in this chapter. The two dispatching subproblems are solved iteratively and optimal values for the various multipliers are communicated between them. The final outcome of the combined algorithm is an optimal unit dispatch schedule that observes the optimal contract consumption sequence for each fuel group, and concurrently satisfies take-or-pay fuel requirements, over-the-limit fuel constraints, and the imposed environmental constraints.

Table 5.1 Output Results from the Combined Dispatch Test Case

	Power	Fuel	Cost	SO_2	NO_X
			Unit Results		
1	3192.29	39656.58	51315.58	18.035	18.293
2	3536.64	43280.94	56005.47	21.911	18.777
3	3327.65	41473.40	53666.71	9.401	19.104
4	6145.17	70121.48	87511.67	24.630	30.782
5	4536.87	51048.80	63709.11	17.466	29.963
6	19807.30	179164.86	223597.66	69.765	42.462
7	9150.89	94559.14	118009.71	33.323	27.254
8	3468.50	40700.13	53195.15	20.688	16.132
9	21147.67	196119.91	256328.77	46.430	24.009
10	16737.00	156687.67	204790.81	58.732	17.020
11	28061.22	262125.03	345880.66	68.244	37.464
12	28126.66	263518.16	347718.93	67.220	36.999
13	30590.39	279581.59	359541.91	73.760	31.833
14	30515.11	281219.47	371076.26	72.781	31.692
15	41540.06	359263.03	474056.72	173.903	73.588
16	39892.30	342693.78	452193.17	167.054	67.276
17	3380.52	39867.11	54324.36	11.472	15.920
18	6556.50	66099.77	90069.92	21.505	33.390
19	6988.18	70960.40	96693.19	26.259	25.226
20	7364.64	72676.31	99031.35	25.868	25.930
21	2280.90	27401.40	37544.93	7.191	6.879
22	6720.46	73882.05	101231.93	25.078	29.826
23	8195.18	86972.85	119168.73	30.787	31.267

Table 5.1 (continued)

	Power	Fuel	Cost	SO_2	NO_X
24	13901.31	138725.28	190079.03	49.634	53.582
25	8432.64	98500.49	134963.70	33.473	25.498
26	55525.82	482241.75	660759.49	196.955	110.231
27	3014.91	33379.96	41171.14	10.905	12.080
28	12000.00	126874.50	156488.12	48.386	23.464
29	13159.88	134482.53	165871.93	36.970	7.631
30	13796.01	143649.48	177178.53	34.422	8.695
31	15725.62	164236.83	227008.84	40.978	11.694
32	14865.30	159048.83	219837.97	38.202	11.413
33	32631.61	291356.09	365574.76	170.003	59.794
34	37059.10	330530.00	414727.64	193.045	69.557
35	3874.71	41960.18	56007.58	8.331	7.660
36	3853.09	42356.02	56535.94	8.174	8.082
37	960.00	14628.55	19525.89	4.190	5.479
38	2324.77	26995.44	36032.96	6.932	7.471
39	2780.87	32661.41	43595.78	7.349	13.956
40	2879.00	33768.60	45073.63	7.862	15.153
41	3975.21	45796.63	61128.40	12.394	7.811
42	3594.05	41962.49	56010.67	11.203	7.250
43	12600.00	140756.78	181956.79	52.049	25.390
44	18891.66	169183.52	218704.13	56.254	42.943
45	24036.16	206091.13	266414.73	135.242	52.819
46	37641.92	303062.97	391770.57	194.551	78.649
47	11415.60	110474.98	149472.48	41.060	47.078
48	11381.03	110152.89	149036.95	44.074	46.528

Table 5.1 (continued)

	Power	Fuel	Cost	SO_2	NO_X
49	14781.91	137077.16	185465.59	60.572	15.406
50	13755.01	138295.42	187113.31	55.283	13.551
			Power Plant Results		
1	10056.58	124410.92	160987.77	49.346	56.174
2	39640.23	394894.25	492828.16	145.184	130.461
3	41353.17	393507.69	514314.72	125.849	57.161
4	198725.75	1788401.00	2359840.69	622.962	278.851
5	24289.85	249603.59	340118.83	85.105	100.466
6	95056.32	907723.88	1243747.90	343.117	257.283
7	41970.80	438386.50	540709.75	130.684	51.870
8	100281.64	945171.75	1227149.30	442.227	152.458
9	11012.58	125940.19	168102.36	27.626	28.692
10	13229.13	154189.13	205808.47	38.807	44.171
11	93169.74	819094.38	1058846.20	438.097	199.801
12	51333.54	496000.44	671088.38	200.990	122.563
			Fuel Group Results		
1	10056.58	124410.92	160987.77	49.346	56.174
2	39640.23	394894.25	492828.16	145.184	130.461
3	41353.17	393507.69	514314.72	125.849	57.161
4	198725.75	1788401.00	2359840.69	622.962	278.851
5	24289.85	249603.59	340118.83	85.105	100.466
6	95056.32	907723.88	1243747.90	343.117	257.283
7	41970.80	438386.50	540709.75	130.684	51.870
8	30590.92	323285.66	446846.81	79.180	23.107

Table 5.1 (continued)

	Power	Fuel	Cost	SO_2	NO_X
9	69690.72	621886.13	780302.45	363.048	129.351
10	24241.71	280129.31	373910.83	66.434	72.863
11	93169.74	819094.38	1058846.20	438.097	199.801
12	51333.54	496000.44	671088.38	200.990	122.563
System Results					
	720119.31	6837323.50	8983542.53	2649.996	1479.950

6. TRANSMISSION COST ALLOCATION USING COOPERATIVE GAME THEORY

This chapter addresses the problem of allocating transmission costs in a fair manner among the users of the transmission grid. A cooperative game theoretic framework was developed and evaluated. The first section of the chapter provides a general introduction to game theory and the second section presents a literature review. Section 6.3 discusses cooperative games and proposed solution concepts. Subsequently, section 6.4 sets up a transmission cost allocation scheme. Numerical results are presented in section 6.5 and the final section provides a chapter summary. Parts of this work have been developed during the author's summer internship with Pacific Gas & Electric, in San Francisco, California. Guidance and contributions from H. Singh and A. Papalexopoulos are hereby thankfully acknowledged.

6.1 Introduction

Passage of FERC Orders 888 and 889 was the latest in a series of legislative actions that effectively opened the transmission sector to competition. The new operational environment presents some functional and technical difficulties that need to be resolved [5,88]. Because of the anticipated large number of transmission transactions accommodated in every time period, a critical problem is the development of mechanisms that not only price transmission grid usage in an efficient way, but allocate to every participant his *fair* cost share as well. Although many pricing mechanisms have been proposed to date, none have been universally accepted. The work presented in this chapter assumes that a costing scheme is already in place and examines ways to allocate transmission costs to the users of the system. Game theoretic cost allocations depend on the a priori assumed costing functions.

Game theory, first established in the late 1920's by von Neumann and Morgenstern (although their famous book "Theory of Games and Economic Behavior" was published just in 1944), is an important branch of operations research. It deals with the logic of decision making in situations where the outcome depends upon the decision(s) of some agents. In a typical problem, two or more participants, called players, choose strategies and make decisions in a conflicting or competitive environment, each player aiming to reach a final outcome as advantageous as possible to his side. Each participant has only partial control over the final outcome. There are several social situations that are never referred to as games in everyday speech, but are indeed games in a game theory context. Political, military, and other clashes are also considered as games.

Games may be classified based on a number of their attributes, e.g. number of players, whether the game is repeated in time or not, etc. According to one such classification, games are divided into cooperative and non-cooperative types. As it is implied by the name, cooperation between the players of a non-cooperative game is forbidden. However, the interests of the players in such a game need not be conflicting. Although a very interesting branch of game theory, non-cooperative games are not considered in the remainder of this chapter.

On the other hand, cooperation is allowed among the players of a cooperative game. Pre-game agreements often come into play and the players are free to form coalitions of any size. The members of a coalition agree that they will somehow correlate their strategies. Each coalition tries to reach a final payoff that is as advantageous as possible. This payoff becomes a function of the coalition. Therefore, the selection of optimal *individual* strategies is no longer the main issue in cooperative games. Instead, the formation of coalitions is what matters the most.

Cooperative game theoretic models are a strong candidate in providing the necessary framework for developing an efficient cost allocation mechanism. Such models have been used extensively to solve problems of cost allocation and division of common property, and provide a flexible framework to parametrically analyze the problem under consideration.

Game theory is a still-developing field and its contributions and models have been recognized and used in many scientific fields, such as economics, public policy, industrial organization, etc. The 1994 Nobel Memorial Prize in Economics was awarded to three prominent game theorists, J. Harsanyi, J. Nash, and R. Selten, for their contributions to the field. However, the applicability of game theory to power systems problems, and to transmission analysis more specifically, has been viewed with skepticism by some experts. This occurs because it is not clear whether the complexities of the interconnected power system can be accurately captured and modeled by game theory. Moreover, cooperative games also received criticism, because some researchers question whether the players' behavior can obey or be subject to axiomatically proposed concepts. Nonetheless, cooperative games have been used to model several social situations and produced informative results. The framework proposed herein specifically examines the negotiating power of the game participants, as measured by the different solution concepts. Careful study of game theory results should provide significant insight to the transmission network users and should be helpful in their efforts to successfully compete during the transitional period to a competitive transmission market.

6.2 Literature Review

Transmission pricing is a subject that received considerable attention and many researchers proposed different pricing mechanisms [89,90,91,92]. References [93,94] review some of the most commonly adopted pricing schemes. However, there is no single transmission pricing approach that is accepted by all interested parties. Reference [95] provides an excellent comprehensive bibliography list on transmission access issues with particular attention to transmission economics and pricing.

Game theoretic models were applied to power system problems long before the introduction of competition in the power industry. Breton *et al.* [96] discussed a game theoretic scheme to efficiently manage an interconnected power system. The optimal dispatch of two hydrothermal systems was modeled as a stochastic control problem and was solved using cooperative game theory concepts. Bargaining solutions were analyzed to determine the optimal prices for energy transactions between the two systems. The goal of the paper by Hobbs *et al.* [97] was to show how game theory might be a helpful tool in identifying and designing transmission pricing policies. However, the operational environment for their models was price regulated. Three groups of pricing policies were examined: i) status quo, ii) planning approach, and iii) contract approach. The basic difference among the three groups was the degree of regulation involved. Cooperative game models were used to analyze short-term, nonfirm power transactions.

More recently, analysis of transmission transactions, in a deregulated environment this time, was discussed in the papers by Ferrero *et al.* [98] and Bai *et al.* [99]. The former modeled the transactions within a regional power pool as a cooperative game. The possible player coalitions as well as their strategies were developed and analyzed. The players' behavior in a perfect competitive environment versus their behavior in an imperfect competitive environment was examined. The paper concluded that participants would be able to increase their benefits by coordinating bid strategies and sharing savings. The latter paper used cooperative game theory as well, and modeled the transmission users as the players of a Nash bargaining game. In such a game, acceptable solutions satisfy the axiomatically given Nash conditions of individual rationality, feasibility, Pareto optimality, independence of irrelevant alternatives, independence of linear transformations, and symmetry [100]. The conclusions reached were similar to those of the previous reference. Numerical results supported the hypothesis of increased profits if players scheduled transmission transactions in a cooperative way. Tsukamoto *et al.* [101] used cooperative game solution concepts to allocate transmission fixed costs among the transmission network users. The solution concepts of the core and the nucleolus were used and results were compared and analyzed. Finally, Singh *et al.* [102] presented the basic cooperative game concepts and applied the nucleolus and the Shapley value solutions to the allocation of transmission costs. The core, the nucleolus, and the Shapley values are explained in a later section.

Besides transmission-related problems, game theory has been used to model several other power system problems. The optimal operation of non-commercial power plants was addressed in the paper by Maeda *et al.* [103]. Haurie *et al.* [104] used a Stackelberg equilibrium method to solve the cogeneration problem. The typical Stackelberg problem is characterized by a strong agent who acts as the "leader" whereas the remaining agents act as "followers". Kuwahata *et al.* [105] discussed the cooperation between an electric utility and a cogenerator to determine prices for power transactions.

Game theoretic approaches addressed these power system problems from a different viewpoint than that of the traditional electrical engineer. However, as already indicated, critics argue that game theory is limited to small problems and may not be able to address the complexities of the power network in their entirety. Nonetheless, despite their limitations, game theoretic models can provide interesting insight to many power systems issues.

6.3 Cooperative Games

6.3.1 Definitions

There are many ways to formally describe a cooperative game [106]. The most common one is by means of a *set of players*, Π, and a *characteristic function*, Φ. Π is the set of the entities that participate in the game. The nature of the players depends on the particular problem; obviously, they need not be living creatures. As it will be discussed later, transmission transactions would be the players in a game theoretic transmission cost allocation model. Any subset of Π is a *coalition*. The coalition of all players (the entire set Π) is called the *grand coalition* and consists of π members (π-players game). Usually, the empty subset of Π is also considered a feasible coalition, called *empty* coalition. Players form coalitions in anticipation of more advantageous payoffs. In return, they agree to correlate their strategies, or in a way, give up their independence as individual players of the game. In order for coalitions to form, it must be somehow assured that the coalition payoff will be at least equally or hopefully more advantageous than the sum of the payoffs the coalition members can get if they act independently. If that is the case for at least one coalition, then the game is *essential*. Payoffs may not be directly monetary, but must ultimately result in making one or more players better off.

The characteristic function, defined over the set of all possible coalitions, assigns to each coalition its worth. In other words, it assigns to each coalition the most advantageous payoff this coalition is assured of obtaining – provided that its members coordinate their strategies in a prescribed way – no matter what the remaining players will do. The characteristic function provides a way to measure the strength of each coalition. By definition, the worth of the empty coalition is always equal to zero, i.e. $\Phi(\{\}) = 0$. Depending on how a game model is set up, a coalition's worth is a lower or an upper bound of the amount to be allocated to this coalition.

If a cooperative game is essential, then Φ exhibits the property of superadditivity

$$\Phi(\Pi_1 \cup \Pi_2) \geq \Phi(\Pi_1) + \Phi(\Pi_2) \qquad \forall \Pi_1, \Pi_2 \subseteq \Pi,\ \Pi_1 \cap \Pi_2 = 0 \qquad \text{(Eq. 6.1)}$$

The weakest form of superadditivity is additivity. Games with additive characteristic functions are called *inessential* and their solution is trivial.

By participating in a cooperative game, each player expects to receive his "fair" share of the total payoff available to the entire set of players, $\Phi(\Pi)$. Each player expects to receive individually a payoff at least equal to his worth, that is

$$\Delta_\rho \geq \Phi(\rho) \qquad \rho = 1, \ldots, \pi \qquad \text{(Eq. 6.2)}$$

where Δ_ρ is the payoff to player ρ. Also, it must hold true that

$$\Delta(\Pi) = \sum_{\rho=1}^{\pi} \Delta_\rho = \Phi(\Pi) \qquad \text{(Eq. 6.3)}$$

Equation (6.2) is usually referred to as *individual rationality* criterion and Equation (6.3) as *Pareto optimality* criterion. A distribution $\Delta = (\Delta_1, \ldots, \Delta_\rho)$ that satisfies the conditions described by Equations (6.2)–(6.3), or in other words, an individually rational and Pareto optimal distribution of the total payoff $\Phi(\Pi)$, is called an *imputation*. The notion of imputation provides an explanation of why it is convenient to consider games with 3 players. The set of imputations of such a game is a 3-dimensional plane and can be easily presented geometrically.

6.3.2 Solution Concepts

In most games, there is an abundance of points in the solution space that satisfy the individual rationality and Pareto optimality constraints. In other words, there is a plethora of imputations. Over the years, researchers have tried to develop mechanisms in order to provide a unique, if possible, imputation accepted by all parties involved. This led to a number of solution concepts being presented in the literature.

The von Neumann–Morgenstern (vN-M) solution concept of stable sets historically was the first one presented. One additional definition is in order at this point. An imputation Δ1 is said to *dominate* another imputation Δ2, if there is a subset of players who all prefer Δ1 over Δ2. A stable set – or vN-M solution – consists of all imputations with the following properties: i) no imputation in the set dominates any other imputation in the set, and ii) any imputation outside the set is dominated by at least one imputation inside the set. The first condition provides for *internal stability* and the second for *external stability*. However, neither uniqueness, or existence of a stable set are guaranteed. In 1968, a 10-player game was constructed that did not have a vN-M solution.

If Equation (6.2) is extended to cover all possible coalitions

$$\Delta(\Gamma) \geq \Phi(\Gamma) \qquad \forall \Gamma \subseteq \Pi \qquad \text{(Eq. 6.4)}$$

where $\Delta(\Gamma)$ is the payoff to coalition Γ

$$\Delta(\Gamma) = \sum_{\rho \in \Gamma} \Delta_\rho \qquad \text{(Eq. 6.5)}$$

one arrives at the *coalitional rationality* criterion (or stand-alone test). Clearly, the condition described by Equation (6.4) includes the condition of Equation (6.2).

The set of imputations satisfying Equations (6.4)–(6.5) is called the *core* of the game. The core of the game is one of the most important solution concepts for it identifies the entire set of imputations that will be acceptable by all parties involved. However, the problem with the core is that in several interesting games it is either too big, or empty.

Another important solution concept is the *Nucleolus*. The Nucleolus was first presented in 1969. Its major advantage is that it consists of a unique imputation for a given game. The calculation of Nucleolus may be explained by means of the notion of the *least core* as an intermediate step. The shape and the size of the core depend on how strong the rationality constraints are. Weak constraints result in a large core whereas strong constraints may result in an empty core. Starting with a non-empty core, its size may be reduced by uniformly strengthening the rationality constraints, or in other words, by increasing the worth of each coalition. That is equivalent to saying that the hyperplanes defining the core are all "pushed" equidistantly inside thus, reducing the size of the core. The "push" is stopped whenever a further push makes the interior of the "reshaped" core empty. The hyperspace defined by the modified constraints is called the *least core*. A game with an empty core may acquire a least core by equally relaxing the apparently too strong constraints until a core is available.

In general, the least core is a convex set of dimension less than the dimension of the core. This is true because at the point where the "push" stops, some of the rationality constraints coincide. This procedure is repeated, with the least core at this time, further reducing its dimension, until a unique point is reached. This point is the Nucleolus of the game. Provided that the game possesses a non-empty core, the Nucleolus, by definition, belongs to the core. The uniqueness and the existence of the Nucleolus have been proved. The Nucleolus provides a "fair" allocation of the common property $\Phi(\Pi)$, since it minimizes the largest deviation from the amount a coalition can assure regardless of the behavior of the remaining players. In other words, it minimizes the largest deviation from the worth of the coalitions. Despite its advantages, the Nucleolus concept has been accused that it does not accurately account for the relative worth of the players. Several rationality constraints may not be given significant consideration in the calculation of Nucleolus if they don't cause large deviations.

Another important solution approach is the Shapley value. While the Nucleolus is the outcome of an iterative optimization process, Shapley values are the outcome of a function. Shapley defined this function axiomatically: the Shapley function is additive, charges null players nothing, and is symmetric, i.e., if the roles of the players change, their allocations are not affected. *Null* is a player whose contribution to every coalition he joins is zero, that is

$$\Phi(\Pi_1 \cup \{\rho\}) = \Phi(\Pi_1) \qquad \forall \Pi_1 \qquad \text{(Eq. 6.6)}$$

It has been proven that the Shapley values are unique. Furthermore, it has been proven that they always lie within the core of a cooperative cost allocation game with a concave cost function. Shapley values are given by

$$\Xi_\rho = \sum_{\rho \in \Gamma} \frac{(\pi - |\Gamma|)!(|\Gamma| - 1)!}{\pi!} (\Phi(\Gamma) - \Phi(\Gamma - \{\rho\})) \qquad \text{(Eq. 6.7)}$$

where the sum is taken over all coalitions that contain ρ. Assume that there are equal probabilities for the occurrence of a given sized coalition. The above equation may be interpreted as that a player ρ should receive the average of all of his contributions to any coalition in which he participates. The intuitive explanation of the Shapley value is as follows: an initially empty coalition has, by definition, zero worth. If it is assumed that players join this initially empty coalition one by one until the grand coalition is formed, it is easy to determine how much value each player adds to the coalition. The Shapley value assigns to each player a payoff proportional to the amount that a player adds to the coalition's value. Since the contribution of a player may depend on the order the coalition is formed, all possible permutations are examined. This fact limits the practical size of a problem. The final payoff of a player is the average contribution of the player to all coalitions he joins, taking all possible orderings into account. Shapley values, in short, allocate payoffs to the players according to their relative a priori powers; or, in a different context, they allocate payoffs according to the players' negotiating power. Shapley values were used to analyze the powers of the United Nations Security Council members. The shocking results revealed that the five permanent members hold 98.1% of the power leaving a modest 1.9% to the remaining ten non-permanent members. In a similar analysis, the a priori power indices for a U.S. congressman, a U.S. senator, and the U.S. President are in the ratio of 2:9:350!! So, the President is a priori 175 times more powerful than a single congressman.

There are additional solution concepts presented in the literature, such as the Kernel, the Bargaining Set, etc. There are also solution concepts for particular classes of games, or based on different descriptions of a game.

6.3.3 Comparison of Solution Concepts

The preceding section did not answer the question "which solution methodology to adopt?" However, no definite answer exists for this question. Which solution concept to accept depends on the attributes of the particular application under consideration. The underlying philosophies of the different solution approaches are quite different and, in general, so are the results they yield.

The core is useful in that it provides the entire set of imputations that will keep all coalitions satisfied, some more and some less. If a unique solution is somehow reached, it is useful to always examine whether it belongs to the core.

In the general case, if the superadditivity property is not assumed, the Nucleolus is not monotonic. Monotonicity is the property that indicates that if a coalition's worth is increased, its share should not be decreased. Lack of monotonicity implies that the players have no incentive to economize. However, the Nucleolus guarantees some minimal deviation from the assured allocations. On the other hand, the Shapley values may not lie within the core of a game under certain circumstances. This implies that one or more coalitions have no incentives to participate in the game. In fact, they have incentives not to participate. These concerns are not valid, however, if the characteristic function is superadditive and concave. An additional comment is that, in general, the order of the players with regard to their payoffs is preserved in both Nucleolus and Shapley value solutions.

In symmetric problems, both Nucleolus and Shapley values yield identical results. In non-symmetric games with strong coalitions, a Nucleolus-based allocation is more sensitive to changes to the worth of the coalitions than a Shapley-derived solution. In such games, the range of allocations (difference between minimum and maximum allocation) is larger in Nucleolus-based solutions. The strongest player(s) in a game, – where a player's strength is identified by his contribution to the coalitions he joins – would probably prefer an allocation based on the Nucleolus, whereas the weakest would favor the Shapley values. The converse holds true for games with weak coalitions.

6.3.4 A Small Example Problem

The following example is intended to introduce a simple method of modeling the transmission cost allocation problem, identify the basic components of the game, and demonstrate the concepts presented so far.

Assume there is a single transmission line and its owner uses the following pricing rule: If the power to be wheeled under a contract is less than 100 MW, the user(s) is charged a flat \$1000. Otherwise, if the power to be wheeled is $(100 + \Delta P)$ MW, then the user(s) is charged $\$(1000 + 10\Delta P)$. Further assume that company A (player 1) wants to deliver 80 MW, company B (player 2) wants to deliver 30 MW, and company C (player 3) wants to deliver 40 MW. All three transactions are in the same direction.

If any company contacts the line owner individually, it will be charged \$1000. If companies A and B get together and contact the line owner together, they will be charged \$1100, so they will realize \$900 in savings over the cumulative amount they would have paid, had they contacted the line owner independently. So, $\Phi(1, 2) = 900$. Following the same logic, the game is set up as follows:

$$\Phi(1) = \Phi(2) = \Phi(3) = 0$$

$$\Phi(1, 2) = 900$$

$$\Phi(1, 3) = 800$$

$$\Phi(2, 3) = 1000$$

$$\Phi(1, 2, 3) = 1500$$

The characteristic function, the game imputations, and the final payoffs represent cost savings. If Δ_ρ denotes the payoff to player ρ, the individual rationality criterion requires that

$$\Delta_1 \geq 0$$

$$\Delta_2 \geq 0$$

$$\Delta_3 \geq 0$$

The coalitional rationality criterion requires that

$\Delta_1 + \Delta_2 \geq 900$

$\Delta_1 + \Delta_3 \geq 800$

$\Delta_2 + \Delta_3 \geq 1000$

Finally, the Pareto optimality criterion requires that

$\Delta_1 + \Delta_2 + \Delta_3 = 1500$

The triangle 1-2-3 in Figure 6.1 is the set of imputations. This set is reduced to the core of the game (blackened area) by the coalitional rationality constraints. The results, according to the Nucleolus and Shapley values solution methodologies, are presented in Table 6.1.

In section 6.5, the same modeling process is applied to a larger network. For the sake of simplicity in resultant presentation, only 3 players were considered. The set up of the game model follows the same steps as in this small example.

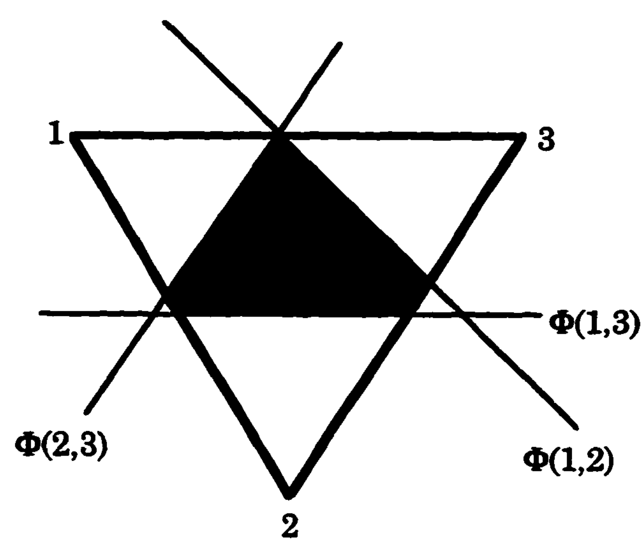

Figure 6.1 Visual Representation of the Solution of the Small Example Problem (Figure not in scale)

Table 6.1 Solution of the Small Example Problem

	Nucleolus	Shapley values
Profit Allocation	$\Delta_1 = 400$	$\Delta_1 = 450$
	$\Delta_2 = 600$	$\Delta_2 = 550$
	$\Delta_3 = 500$	$\Delta_3 = 500$
Corresponding Costs	$\varepsilon_1 = 600$	$\varepsilon_1 = 550$
	$\varepsilon_2 = 400$	$\varepsilon_2 = 450$
	$\varepsilon_3 = 500$	$\varepsilon_3 = 500$

6.4 Transmission Cost Allocation Game Modeling

As already mentioned in the chapter introduction, the electric utility industry faces a number of challenges today, as a result of moving towards a more competitive environment. In general, a large number of transmission transactions are accommodated simultaneously and there are many entities utilizing the transmission grid at the same time. One problem that needs to be addressed is the development of universally accepted transmission costing approaches and subsequently the development of cost allocation schemes to fairly charge each participant for his share of the cumulative transmission costs. Game models are particularly suitable for cost allocation and division of common goods problems. However, there is more than one way to set up a cost allocation game model.

6.4.1 Benefit Games

The players of a game form coalitions and agree to correlate their strategies in return for more advantageous payoffs than if they had entered the game as individual agents. In a cost allocation cooperative game, all players expect to pay less, or in other words, to save over the amount they otherwise would have to pay had they acted independently. Therefore, it is convenient to model the game with regard to the savings realized over the costs that would have incurred in a non-cooperative scenario. The characteristic function, the game imputations, and the final payoffs represent profits (or benefits, or cost savings). Such a game is said to have been developed within the *profit framework*. The values of the characteristic function of a benefit game are the lower bounds of the final payoffs.

Developing a game in the *cost framework* results in an equivalent model. In such a game, the characteristic function and the game imputations represent costs. The final payoffs are each player's actual cost share. However, the players in a cost game can not perceive directly how much savings they had realized as a result of their cooperation. The characteristic function values are upper bounds of the final payoffs.

It should be stated that the only difference between the two modeling frameworks is in the development of the characteristic function. The philosophies behind both frameworks are identical: players and coalitions cooperate in anticipation of decreasing their costs (cost framework) or equivalently, realizing savings (profit framework). The final payoffs satisfy the criteria of individual and coalitional rationality and Pareto optimality. Although the two models are equivalent, there are some special games in which one type is preferred over the other. Finally, it should be noted that some of the definitions in the previous section have assumed a benefit game.

6.4.2 Separable Costs

A cost allocation game may be modeled using the concept of the separable costs [107]. The separable costs of a coalition Γ, $\zeta(\Gamma)$, are defined as follows:

$$\zeta(\Gamma) = \varepsilon(\Pi) - \varepsilon(\Pi - \Gamma) \qquad \forall \Gamma \subseteq \Pi \qquad \text{(Eq. 6.8)}$$

where $\varepsilon()$ is the cost function of the game. The *separable costs criterion* requires that a game allocation satisfies the following constraint:

$$\Delta(\Gamma) \geq \zeta(\Gamma) = \varepsilon(\Pi) - \varepsilon(\Pi - \Gamma) \qquad \forall \Gamma \subseteq \Pi \qquad \text{(Eq. 6.9)}$$

This criterion provides for an alternative modeling framework, the separable costs framework. The characteristic function in such a game represents separable costs. The break-even constraint (or Pareto optimality constraint) must also be satisfied. It has been proved that the separable costs criterion together with the Pareto optimality criterion are equivalent to the two rationality criteria (coalitional and individual) considered together with the Pareto optimality criterion. The final payoffs are each player's cost share. Although the separable costs modeling views the cost allocation problem from a different viewpoint and provides significant insights, it may exhibit problems in games with a large number of players and incomplete data availability. In such instances, setting up the characteristic function is troublesome.

6.5 Numerical Results

6.5.1 Description of Test Cases

The test system used is shown in Figure 6.2. Line reactances are presented in Table 6.2. There are two native loads (Buses 3 and 6) and two native generators (Buses 1 and 4) in this system. Buyers and sellers potentially exist at Buses 2, 3, 4, and 5. The generator at Bus 4 is switched on on hour 10 and its output is fixed at 400 MW (or 4 p.u.). This unit is suddenly turned off on hour 18.

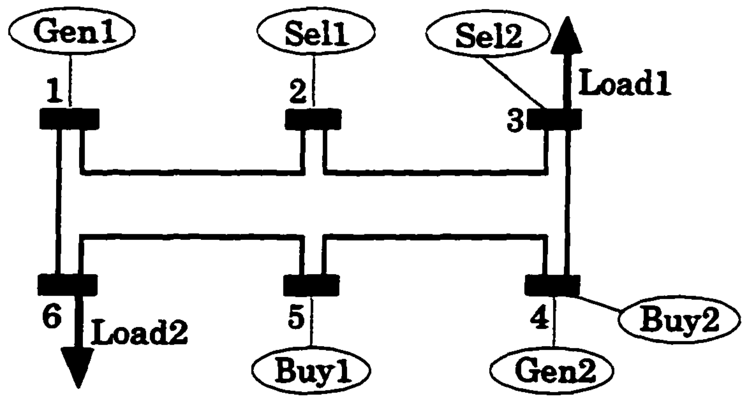

Figure 6.2 Test System

Table 6.2 Test System Line Data

Line #	x (p.u.)
1 - 2	0.37
2 - 3	0.13
3 - 4	1.05
4 - 5	0.64
5 - 6	0.30
6 - 1	0.41

The two transactions are part of a firm power transmission contract and have identical load duration curves. Their chronological load profiles depend on the test case under study.

For the first test case (game 1) both transactions have identical load profiles. The first transaction is from Bus 2 to Bus 5 with a peak load of 400 MW, and the second is from Bus 3 to Bus 4, again with a peak load of 400 MW.

The chronological profiles of the transactions for test case 1, along with the native load profile, are shown in Figure 6.3. Since it is only transaction 1 (player 1) that is modified throughout the different test cases, transaction 2 (player 2) and the native loads (player 3) remain unaltered for all games.

The cost function used for these test cases is based on a capacity charge. Each company is charged based on the peak line loading it causes while delivering power via the grid. Each company is charged \$100/p.u. peak line loading for the 24 hour modeling period. Since power flows are necessary to determine the line loadings, a DC power flow program was used (losses are not considered). Each one of the six lines of the system was checked individually with

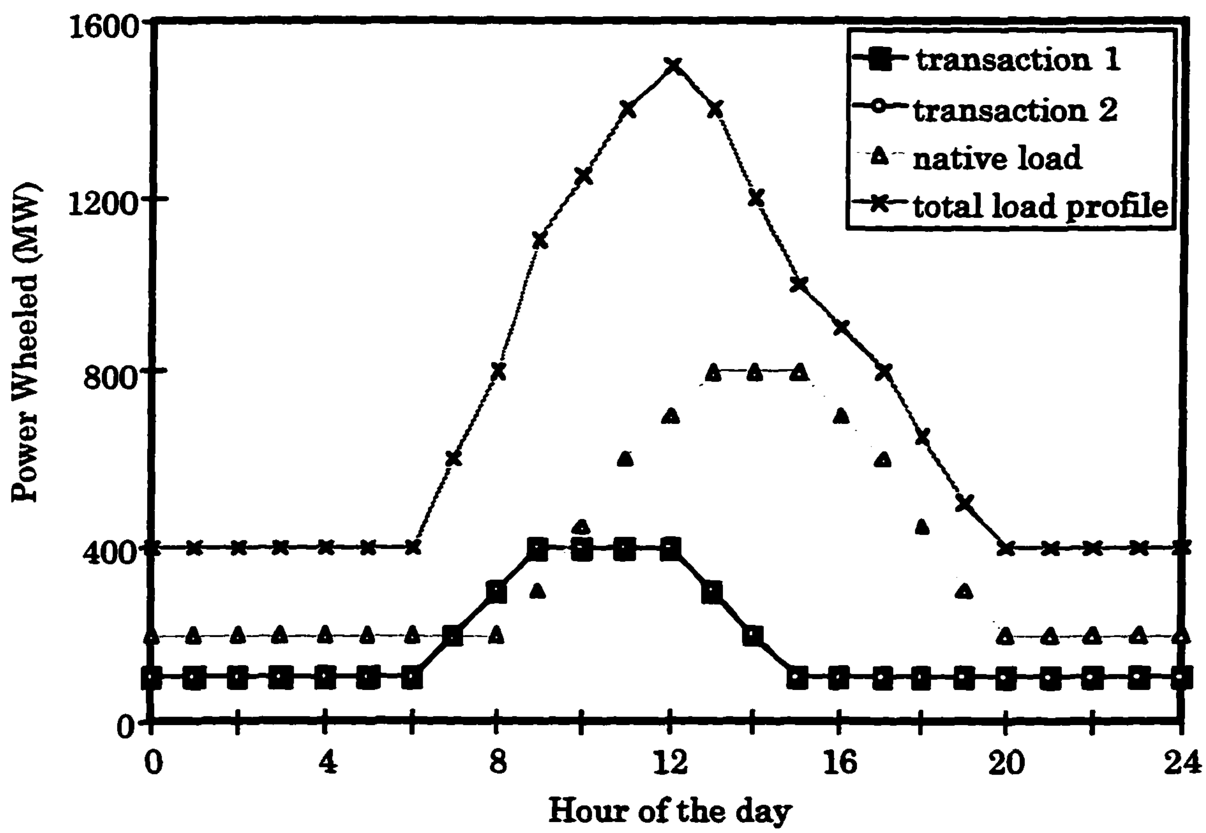

Figure 6.3 Chronological Profile of Transactions in Game 1

regard to its chronological loading. In fact, each test case consists of a set of six dependent single line games.

Four different test cases were performed and their results are presented in this section. These test cases are identified as games 1 through 4 and the differences among them are explained in the next paragraphs. Each test case allocates the cost savings realized through cooperation to the three players involved. Cost savings are realized on a per system line basis; thus, each test case consists of a set of six distinct game theoretic cost allocations. All these test cases last for 24 hours. In the tested games, transmission lines are assumed to have infinite capacity, i.e., no maximum loading limits are present for any of the lines. In reality, this is obviously incorrect. However, even if transmission limits are present and congestion occurs, it is the power flow program that will solve the situation. The cost allocation is executed only after the power flow is completed and individual line flows are calculated. In that context, the presence of maximum allowable line flows does not alter the qualitative characteristics of the game theoretic cost allocation presented in this chapter. The numerical output of the power flow might be different, resulting in a different cost calculation and subsequent allocation.

Another issue is how to handle counterflows. Counterflows occur in most electric networks. In some instances, they may be helpful in utilizing the network more efficiently. In transmission pricing models presented in the past, counterflows either were charged as normal line flows, or were not charged because their importance was recognized, or were even reimbursed (negative charging). In the test cases presented in this section, the significance of counterflows in reducing peak loadings is recognized and they are reimbursed. This explains the negative signs in some of the entries in the results tables that follow.

<u>Game 1</u>: Transactions 1 and 2 occur at the same time and have identical load profiles. The transactions begin with hour 6, end with hour 15, and their peak value is 400 MW each. Buses 2 and 3 are the selling points (for transactions 1 and 2 respectively) and Buses 5 and 4 are the buying points.

<u>Game 2</u>: Transaction 1 starts prior to the beginning of our modeling period, ends with hour 3, and is again repeated, beginning with hour 18. In other words, the load profile of transaction 1 is shifted both backwards and forward in time by 12 hours compared to game 1.

<u>Game 3</u>: This game is nearly identical to game 1; the only difference is that the selling and buying points of transaction 1 are reversed. So, Bus 5 is now selling power to Bus 2. The chronological load profiles are as in game 1.

<u>Game 4</u>: This game is nearly identical to game 2; the only difference is that the selling and buying points of transaction 1 are reversed. So, Bus 5 is now selling power to Bus 2. The chronological load profiles are as in game 2.

6.5.2 Implementation

A simple DC power flow program was developed using the modeling language AMPL [108]. The game solutions were calculated using the Mathematica subroutines described in [106]. The remaining costs and savings calculations were performed using Excel.

6.5.3 Input Data

In order to generate the necessary data to run the games, power flows were run to calculate the line loadings for each possible combination of transactions. The set of all possible combinations is {(1), (2), (3), (1,2), (1,3), (2,3), (1,2,3)}, where 1 stands for the first transaction, 2 for the second, and 3 for the native load and generation.

The necessary input data were developed as in the small example problem presented in section 6.3.4. The first three columns of Table 6.3 show the line costs corresponding to each transaction, if each transaction were to be accommodated independently. That is how much money each transaction would cost in a non-cooperative context (non-cooperation mode). These costs are referred to as $\varepsilon 1$, $\varepsilon 2$, and $\varepsilon 3$. The remaining columns with headings $\varepsilon 1+\varepsilon 2$, $\varepsilon 1+\varepsilon 3$, $\varepsilon 2+\varepsilon 3$, and $\varepsilon 1+\varepsilon 2+\varepsilon 3$ present the additive costs of the non-cooperative case for every possible combination of transactions, i.e., simply adding the appropriate entries in the first three columns. Since the costing rule assumed for these test cases depends only on the line peak loadings, and since the profiles of each individual transaction remain unaltered in all games, the input data are common for all games.

Table 6.4 presents the transaction costs corresponding to simultaneously wheeling the combinations (1,2), (1,3), (2,3), and (1,2,3) respectively (cooperation mode). These are the columns with the headings $\varepsilon 12$, $\varepsilon 13$, $\varepsilon 23$, and $\varepsilon 123$. The

Table 6.3 Input Non-Cooperative Cost Data

line	$\varepsilon 1$	$\varepsilon 2$	$\varepsilon 3$	$\varepsilon 1+\varepsilon 2$	$\varepsilon 1+\varepsilon 3$	$\varepsilon 2+\varepsilon 3$	$\varepsilon 1+\varepsilon 2+\varepsilon 3$
1-2	251.03	144.83	338.62	395.86	589.66	483.45	734.48
2-3	148.97	144.83	338.62	293.79	487.59	483.45	632.42
3-4	148.97	255.17	261.38	404.14	410.35	516.55	665.52
4-5	148.97	144.83	198.97	293.79	347.93	343.79	492.76
5-6	251.03	144.83	198.97	395.86	450.00	343.79	594.83
6-1	251.03	144.83	120.35	395.86	371.38	265.17	516.21
total	1200.00	979.31	1456.90	2179.31	2656.90	2436.21	3636.21

Table 6.4 Input Cooperative Cost Data and Corresponding Cost Savings

line	ε12	ε13	ε23	ε123	Δ12	Δ13	Δ23	Δ123
Test case (game) 1								
1-2	395.9	275.9	302.4	346.9	0.0	313.8	181.0	387.6
2-3	4.1	450.3	302.4	341.7	289.7	37.2	181.0	290.7
3-4	404.1	224.1	234.8	383.8	0.0	186.2	281.7	281.7
4-5	4.1	347.9	165.2	203.1	289.7	0.0	178.6	289.7
5-6	395.9	271.4	165.2	416.2	0.0	178.6	178.6	178.6
6-1	395.9	371.4	265.2	516.2	0.0	0.0	0.0	0.0
total	1600.0	1941.0	1435.2	2207.9	579.3	715.8	1001.0	1428.3
Test case (game) 2								
1-2	287.2	275.9	302.4	239.7	108.6	313.8	181.0	494.8
2-3	112.8	375.9	302.4	339.7	181.0	111.7	181.0	292.8
3-4	292.4	224.1	234.8	272.1	111.7	186.2	281.7	393.4
4-5	112.8	236.2	165.2	200.0	181.0	111.7	178.6	292.8
5-6	287.2	254.1	165.2	290.3	108.6	195.9	178.6	304.4
6-1	287.2	354.1	265.2	390.3	108.6	17.2	0.0	125.9
total	1379.7	1720.3	1435.2	1732.1	799.7	936.6	1001.0	1904.1
Test case (game) 3								
1-2	106.2	526.9	302.4	418.3	289.7	62.8	181.0	316.2
2-3	293.8	301.4	302.4	265.2	0.0	186.2	181.0	367.2
3-4	106.2	393.1	234.8	234.9	297.9	17.2	281.7	430.7
4-5	293.8	169.3	165.2	314.1	0.0	178.6	178.6	178.6
5-6	106.2	450.0	165.2	305.2	289.7	0.0	178.6	289.7
6-1	106.2	250.0	265.2	105.2	289.7	121.4	0.0	411.0
total	1012.4	2090.7	1435.2	1642.8	1166.9	566.2	1001.0	1993.5

Table 6.4 (continued)

line	ε12	ε13	ε23	ε123	Δ12	Δ13	Δ23	Δ123
				Test case (game) 4				
1-2	214.8	401.4	302.4	365.2	181.0	188.3	181.0	369.3
2-3	185.2	301.4	302.4	265.2	108.6	186.2	181.0	367.2
3-4	217.9	298.6	234.8	234.8	186.2	111.7	281.7	430.7
4-5	185.2	161.7	165.2	202.4	108.6	186.2	178.6	290.3
5-6	214.8	261.7	165.2	225.5	181.0	188.3	178.6	369.3
6-1	214.8	147.9	265.2	202.4	181.0	223.4	0.0	313.8
total	1232.8	1572.8	1435.2	1495.5	946.5	1084.1	1001.0	2140.7

adjacent columns, Δ12, Δ13, Δ23, and Δ123, present the difference in costs (or cost savings, or profits) between the cooperation and the non-cooperation modes. These numbers result by subtracting the appropriate non-cooperative cost data (Table 6.3) from the corresponding cooperative cost entries in the first four columns of Table 6.4. For example, if transactions 1 and 3 are to be performed in a non-cooperative scenario, they result in a cumulative peak flow of 2.93794 p.u. on line 2-3 with a corresponding cost of \$293.794 (column ε1+ε2, row 2-3, of Table 6.3). If the same transactions are performed cooperatively following the scenario of game 1, the corresponding cost is \$4.138, which implies a cost saving of \$289.656 for line 2-3 for the 24-hour modeling period. According to the game formulation, the total payoff to be distributed is the worth of the grand coalition, $\Phi(\Pi)$. With reference to the input data, the per line profits to be distributed for each game are tabulated in column Δ123, profits for the big coalition.

Tables 6.3–6.4 include all the necessary input data for cost allocation calculations either in a cost or in a profit framework. A profit framework was assumed during the execution of the presented test cases, i.e., cost savings (or profits) are the quantity distributed. Transaction costs follow logically. Cost allocation may be also performed in a separable cost framework or directly in the cost framework.

6.5.4 Output Results

Profits are allocated to the players of the game, i.e., transactions in the presented test cases, according to the two most widely used solution methodologies, namely Nucleolus and Shapley values. The allocated profits are subtracted from the corresponding costs to determine the final cost allocations. The results presented in Table 6.5 are the final cost allocations. The symbols Nε and SVε are used for the final cost distribution according to Nucleolus and Shapley values respectively, to differentiate the output cost allocation from the input cost data. The total amount of cost savings for each line is of course equal for each method and also equals the respective entry in the Δ123 column of the corresponding input data. It is the individual player allocations that depend on the method, not the total amount distributed. It is interesting to note how the two allocation mechanisms yield different results for each transaction-player.

6.5.5 Comments and Observations on Results

A number of observations are in order at this point. The test cases clearly indicate the large cost savings realized through cooperative accommodation of multiple transactions. In some instances, costs are reduced by more than half when independent transactions cooperate. In such cases, it would be beneficial for the power wheelers to contact the transmission owner as a group and not on an

Table 6.5 Output Results

line	Nε1	Nε2	Nε3	total	SVε1	SVε2	SVε3	total
				Test case (game) 1				
1-2	147.8	107.9	91.2	346.9	129.9	90.1	127.0	346.9
2-3	75.8	-72.2	338.1	341.7	57.9	-18.1	301.9	341.7
3-4	149.0	207.4	27.4	383.8	117.9	176.4	89.5	383.8
4-5	93.4	-89.3	199.0	203.1	63.7	-29.8	169.2	203.1
5-6	251.0	144.8	20.3	416.2	221.3	115.1	79.9	416.2
6-1	251.0	144.8	120.3	516.2	251.0	144.8	120.3	516.2
total	968.0	443.5	796.4	2207.9	841.7	478.4	887.8	2207.9
				Test case (game) 2				
1-2	85.1	54.3	100.3	239.7	76.0	36.2	127.4	239.7
2-3	74.5	1.0	264.1	339.7	62.9	24.1	252.6	339.7
3-4	93.1	123.6	55.3	272.1	62.1	120.5	89.5	272.1
4-5	72.9	1.8	125.3	200.0	62.1	24.6	113.3	200.0
5-6	167.1	78.2	45.1	290.3	158.3	60.7	71.3	290.3
6-1	188.1	90.5	111.7	390.3	188.1	90.6	111.7	390.3
total	680.8	349.5	701.8	1732.1	609.6	356.7	765.8	1732.1
				Test case (game) 3				
1-2	158.7	-65.8	325.3	418.3	147.2	-18.1	289.1	418.3
2-3	55.9	54.3	155.0	265.2	55.9	54.3	155.0	265.2
3-4	74.5	-34.7	195.0	234.8	46.8	20.7	167.3	234.8
4-5	149.0	144.8	20.3	314.1	119.2	115.1	79.9	314.1
5-6	195.5	-89.3	199.0	305.2	165.7	-29.8	169.2	305.2
6-1	45.5	0.0	59.7	105.2	45.5	0.0	59.7	105.2
total	679.1	9.4	954.3	1642.8	580.3	142.2	920.2	1642.8

Table 6.5 (continued)

line	Nε1	Nε2	Nε3	total	SVε1	SVε2	SVε3	total
				Test case (game) 4				
1-2	125.5	26.6	213.1	365.2	126.7	24.1	214.3	365.2
2-3	49.0	50.0	166.2	265.2	37.8	36.2	191.2	265.2
3-4	74.5	39.8	120.5	234.8	49.7	70.9	114.3	234.8
4-5	73.0	76.4	53.0	202.4	62.6	62.2	77.6	202.4
5-6	123.9	27.4	74.3	225.5	125.9	24.5	75.1	225.5
6-1	48.8	99.7	54.0	202.4	79.0	84.5	38.9	202.4
total	494.7	319.8	681.0	1495.5	481.7	302.5	711.3	1495.5

individual basis. In addition to the lower transaction costs for the individual transactions, the transmission grid is more efficiently utilized. In the test cases presented, profits are realized as a result of i) the non-coincidence of the transaction load profiles, and ii) counterflows. However, this observation can not be generalized. In general, the cost savings realized depend on the costing rules adopted. These rules must be acceptable by all parties involved, which, itself, is a non-trivial task.

Since the cost function used is concave, the Shapley values always lie within the core. Clearly, different solution methodologies yield completely different results. The coalitions in the tested cases were strong; hence, the Shapley values demonstrate a tendency to increase the minimum profit realized by any player. The range of profits allocated to players, i.e., the difference between the minimum and maximum values, is smaller in the Shapley value results than in the Nucleolus results. The output results indicate that the strongest player, in most instances, would prefer a Nucleolus-based solution, whereas the weakest player would favor a Shapley-based allocation. It is interesting to note that the order of the players, with respect to their profit allocations, is preserved with either solution approach. That is, both solution procedures identify and classify the strengths of the players, or, in other words, their negotiating powers. However, each solution approach weights the strengths on a different scale.

All players are saving over the non-cooperative mode costs; thus, all should be satisfied. The resulting profit allocations provide subsidy-free transmission cost distributions. Furthermore, credit is given to transactions whenever appropriate. However, results depend heavily on the adopted costing mechanism. It should be emphasized that using different transmission cost functions, savings would be greater or smaller and would be realized because of similar or different reasons than the ones identified in the test cases presented.

Game theory provides a suitable framework for the development of transmission cost allocation models. In alternative models, not every line may be an individual game. Moreover, probably not even every transaction should be an individual player. Transactions may be grouped and each portfolio of transactions can be a player in a generalized game. Further, the interconnected power system consists of distinct areas. Whereas in the simple examples presented in this document each line was the environment for a game, in larger scale problems this role may be played by control or geographical areas.

Games provide indications about the negotiating power of each player. Therefore, they may be used in order to identify factors and situations that would strengthen the negotiating power of a player. In that sense, they can be used as strategic planning and development tools to analyze "what if" situations.

6.6 Chapter Summary

Game theory was used to develop a transmission cost allocation scheme. Such schemes attempt to fairly allocate the fixed transmission costs among the multiple users of the transmission network. One of the major difficulties associated with the development of allocation mechanisms is that what may seem "fair" to one participating party, may seem completely unfair to another party. An allocation framework was developed using simple costing rules. Two commonly used solution approaches were used to implement cost allocations for a number of test cases. The entire allocation procedure was described in detail and output results were discussed.

7. CONCLUDING CHAPTER

7.1 Research Contributions

In developing the models for this project, flexible accurate models and rapid execution times were two of the primary concerns. The combined scheme presented decouples the problem into two smaller subproblems and treats each subproblem separately. Coordination among the subproblems is provided by means of the updated Lagrangian multipliers. These models might be further enhanced with more sophisticated optimization techniques, possibly requiring increased solution times. Because of the general lack of experience with the effects of interfacing the two sets of complex models, it was decided to use nonlinear methods rather than introducing the effects of linearization. The overall solution approach employs the bisection method to perform the necessary single line searches, but it also uses the proven robustness of Lagrangian multipliers-based schemes to achieve optimal scheduling. The importance of addressing the problem of interfacing fuel and environmental constraints in a single dispatching tool, was presented in the introductory chapter of this dissertation.

However, addressing the combined problem in a concise and consistent manner was only the end result of this project. The individual subproblems, namely fuel-constrained and emission-constrained dispatching, have received considerable attention and sufficient treatment. The contributions of each part of this research work are presented in the remainder of this section.

7.1.1 Fuel-Constrained Scheduling

In the fuel-constrained model, the concept of "fuel groups" was revisited. This concept, originally proposed by Lamont *et al.* [15], was expanded in this work with respect to availability of fuel supplies and contracts. The focus shifted from the fuel networks to the modeling of the fuel supply contracts and their impacts. Multiple fuel contracts may be available, consisting of multiple blocks with minimum and maximum block limits and block prices. This allows modeling the fact that fuel supplies may be purchased in blocks, just like many other commodities. In the conventional economic dispatch development, the fuel at each power plant or generating unit has been associated with a single price. In order to provide more realistic modeling of fuel prices, escalating as well as fixed prices were considered for each type of fuel. Escalating prices may be increasing or decreasing to represent incentives or disincentives to consume. The result of the corresponding optimization problem is the presented optimal consumption ordering of the available fuel contracts, which is an original development. This ordering provides power producing companies with an accurate way to determine their fuel expenses based on their forecasted load requirements, and to consume fuel supplies in the least costly manner. These new models of the fuel supply side were subsequently incorporated into a conventional fuel-constrained dispatch algorithm.

7.1.2 Emission-Constrained Scheduling

On the emission side, classes of emission constraints were defined in order to categorize the possible environmental limitations imposable on power generation facilities. Although the main focus is currently on the federal air pollution limitations, power facilities are also subject to local constraints. Classification of the various emission targets recognizes the need for simultaneous and synchronized satisfaction of all applicable constraints. It was also recognized that various pollutants exhibit different degrees of correlation with the fuel supplies used. For example, dispatching a system subject to limited NO_X emissions, may increase or decrease its SO_2 emissions with respect to the economic dispatch emission levels. Thus, a multi-pollutant problem is a multi-objective optimization problem and was treated as such. Emission allowances, a new concept introduced by the 1990 CAAA, are fully recognized as an integral cost component that must be accounted for in dispatching calculations. The resulting multipliers from the final generation schedule, may be used to indicate to the company management whether it should engage in more aggressive allowance trading. Although allowances are currently priced at levels lower than initially anticipated, it is expected that their prices will rise in the near future, beginning with phase II of the compliance program.

As previously stated, the developed optimization technique combines the necessary elements for simplicity and fast execution, such as single line searches, with the likewise necessary elements to ensure the robustness of the overall algorithm, such as coordination between the different levels via Lagrangian multipliers. A methodology with some similarities to the one developed within this project, was developed independently during the same time frame, by Lee *et al.* [71]. However, in the author's opinion, the models developed in this work present a much higher degree of modeling accuracy and perform a multi-level optimization process in order to satisfy not only multiple pollutants, but multiple classes of emission constraints as well.

Interest in emission-constrained dispatching should be renewed as we get closer to the implementation of phase II and the increased current federal interest in CO_2 and particulate emissions. The algorithm, models, and corresponding software developed during this work have extended the capabilities of the algorithms presented so far and should be a useful tool for power producers in their efforts to comply with emission regulations.

7.1.3 Transmission Cost Allocation

The last part of this work reported on the applicability of cooperative game theory on the allocation of transmission costs. Shapley values previously have been recognized as the most promising of the solution concepts classified as "indices of power." This work applied Shapley values to simple cost allocation problems to establish the applicability of cooperative game theoretic solution approaches. In this context, this research extended the very limited experimental work published thus far on the subject, and offered Shapley values as an alternative allocation mechanism to the Nucleolus concept. This is an important addition, because whereas Nucleolus basically attempts to minimize the maximum dissatisfaction expressed by any participating entity, Shapley values reflect the relative negotiating power of each player and allocate costs accordingly. Power producing parties can benefit from cooperative game results, since such results will indicate potentially profitable alliances. Moreover, the availability of various allocation schemes and the comparison of the corresponding results, provides useful insights to the strategic positioning of the various transmission grid users.

7.2 Suggestions for Future Work

Each part of the work presented in this dissertation can be expanded to include additional features.

The fuel-constrained dispatch could be enhanced to include:

- fuel network models

- availability of fuel storage
- options for fuel trading, in case of favorable fuel market conditions
- fuel blending models.

The emission-constrained dispatch could be expanded to include:

- start up and shut down emission models
- improved unit emission modeling
- emission allowance trading capabilities, once full scale allowance markets are established
- multiple hour / multiple unit emission limit enforcement
- use as a part of power bidding strategy decisions.

The further enhanced dispatch algorithm could be interfaced with a unit commitment program and/or a previously developed fuzzy logic scheduling algorithm to produce an operational as well as planning tool.

Since on-line implementation was a major motivation during the development of this work, ways of improving execution times should be investigated. These may include alternative approaches in constraint processing, faster single line searches, use of acceleration factors, and improved constraint screeening methods. Further, efficient ways to detect and correct cycling may be researched.

Allocating transmission costs in a fair manner, acceptable by all parties involved, is an ongoing issue that depends largely on political decisions yet to be finalized. The work on this issue presented in this dissertation, may serve as a guideline on the applicability and usefulness of game theoretic models. Alternative pricing schemes may be used, once such schemes are agreed upon by all participating companies or established by regulatory agencies. Further, additional solution concepts might be used and the corresponding results could be comparatively analyzed with the results from Nucleolus and Shapley solutions. Finally, the applicability of non-cooperative game theory should be investigated and non-cooperative game models should be developed for additional insight.

7.3 Conclusions and Summary of Work

The research presented herein focused on the development and implementation of enhanced dispatching strategies that incorporated fuel and emission constraints of various types, as well as the development and evaluation of a transmission cost allocation mechanism based on cooperative game theory.

Modeling of the fuel supply has been inadequate in the dispatching schemes presented thus far and failed to capture the competitive forces of fuel markets. This work introduces an optimal consumption ordering of fuel blocks and correspondingly, fuel price schedules with entries dependent on forecasted fuel needs. Fuel prices are no longer fixed, single level parameters. Fuel limits can be more accurately modeled. The complete fuel dispatch mechanism has the capability of handling take-or-pay fuel contracts as well as over-the-limit fuel constraints, by means of a Lagrangian multipliers based updating process.

Environmental constraints are still one of the major concerns of power producers. Federal as well as local limitations may be constraining emisssions of various pollutants. The developed dispatch methodology includes constraints over varying numbers of time periods as well as constraints limiting different subsets of generating units. The complete algorithm possesses also the capability of including the worth of emission allowances in the dispatch calculations.

Interfacing the two dispatch modules produces an enhanced dispatching tool that can successively satisfy fuel and emission constraints simultaneously.

Numerical results have indicated reasonable execution times, thus making the presented approach suitable for on-line implementation.

Cooperative game theory concepts have been used extensively in models developed for economic problems. They have also been used to propose solutions for several power systems problems in the past. One of the problems that emerged from the opening of transmission networks to competition, is the efficient and fair allocation of transmission costs to transmission grid users. A mechanism to perform such an operation is developed. Capacity-based costing rules are followed in order to evaluate the proposed framework for some simple transmission scenarios. Cooperative game solution concepts are applied. The output results are interesting in that they identify the relative negotiating powers of the participating entities. Hence, the developed framework may be of assistance in order to not only perform actual cost allocations, but investigate "what if" scenarios.

APPENDIX. TEST DATA

Table A1. Unit Fuel Coefficients

Unit i	$f_{i,a}$	$f_{i,b}$	$f_{i,d}$
1	+4.91252E+01	+1.00849E+01	+5.55911E-05
2	+6.30687E+01	+9.47263E+00	+1.32030E-04
3	+5.80768E+01	+9.78112E+00	+1.04600E-04
4	+1.15790E+02	+8.28213E+00	+1.51298E-04
5	+4.08594E+01	+9.83925E+00	+6.69778E-05
6	+5.32498E+01	+8.52691E+00	+4.41090E-06
7	+5.82490E+01	+9.28746E+00	+7.62027E-06
8	+5.18628E+01	+9.35120E+00	+2.20925E-04
9	+1.38514E+02	+7.65466E+00	+3.05310E-05
10	+1.06755E+02	+7.97224E+00	+2.90514E-05
11	+7.59211E+01	+8.69354E+00	+4.75855E-06
12	+8.60796E+01	+8.68309E+00	+4.55527E-06
13	+1.73124E+02	+7.68484E+00	+1.39491E-05
14	+1.83389E+02	+7.71180E+00	+1.37872E-05
15	+2.31141E+02	+7.34518E+00	+5.15577E-06
16	+2.30881E+02	+7.23297E+00	+6.11535E-06
17	+5.48664E+01	+9.22072E+00	+2.43461E-04
18	+1.28143E+02	+6.28414E+00	+4.44444E-04
19	+9.28283E+01	+8.24405E+00	+8.97951E-05
20	+8.95153E+01	+8.06570E+00	+8.85299E-05
21	+4.34687E+01	+9.61423E+00	+2.98455E-04
22	+7.05720E+01	+9.19578E+00	+1.02912E-04
23	+9.28344E+01	+8.62551E+00	+9.12479E-05
24	+1.91700E+02	+7.78180E+00	+1.45983E-05
25	+1.01700E+02	+9.80180E+00	+2.08321E-05

Table A1. (continued)

Unit i	$f_{i,a}$	$f_{i,b}$	$f_{i,d}$
26	+3.28410E+02	+7.09290E+00	+5.27910E-06
27	+6.31194E+01	+8.46470E+00	+1.49513E-04
28	+1.06470E+02	+8.81950E+00	+6.60177E-05
29	+1.08410E+02	+8.72970E+00	+1.64551E-05
30	+1.75260E+02	+8.05590E+00	+3.10679E-05
31	+1.76800E+02	+8.45730E+00	+2.44011E-05
32	+1.51560E+02	+9.01030E+00	+1.36922E-05
33	+1.89340E+02	+7.57660E+00	+8.82950E-06
34	+2.18280E+02	+7.57990E+00	+6.23960E-06
35	+2.57086E+02	+3.81782E-03	+2.74184E-03
36	+2.23376E+02	+1.69551E+00	+2.26489E-03
37	+4.04252E+01	+9.75192E+00	+6.76587E-03
38	+2.97185E+01	+9.97910E+00	+2.50104E-04
39	+5.12470E+01	+9.35632E+00	+2.95299E-04
40	+5.06696E+01	+9.44378E+00	+2.72428E-04
41	+7.80354E+01	+8.93495E+00	+1.87459E-04
42	+6.35170E+01	+9.39706E+00	+1.61481E-04
43	+1.75920E+02	+8.70820E+00	+2.08682E-05
44	+1.13713E+02	+7.70187E+00	+1.49338E-05
45	+1.61914E+02	+7.31305E+00	+3.56645E-06
46	+2.10620E+02	+7.04756E+00	+7.53264E-07
47	+1.36103E+02	+7.52953E+00	+5.78983E-05
48	+1.67632E+02	+7.06718E+00	+6.39584E-05
49	+1.29019E+02	+7.48885E+00	+3.80494E-05
50	+9.38830E+01	+8.88510E+00	+2.72269E-06

Table A2. Unit NO_X Coefficients

Unit i	$n_{i,a}$	$n_{i,b}$	$n_{i,d}$
1	+1.04458E-01	+6.34024E-04	+3.55595E-07
2	+1.09577E-01	+4.02110E-04	+3.79684E-07
3	+1.08579E-01	+6.29355E-04	+3.53607E-07
4	+1.77452E-01	+6.39346E-04	+1.91962E-08
5	+1.76431E-01	+7.68277E-04	+2.97151E-09
6	+1.05668E-01	+1.30145E-03	+1.61187E-09
7	+9.90552E-02	+1.34226E-03	+1.02867E-09
8	+8.42751E-02	+6.66285E-04	+5.36067E-07
9	+1.25591E-02	+6.25451E-04	+2.41340E-08
10	+1.46772E-02	+5.97859E-04	+2.48275E-08
11	+4.99145E-02	+4.39573E-04	+1.47026E-08
12	+4.33018E-02	+5.05402E-04	+1.46250E-08
13	+2.04723E-02	+4.02512E-04	+1.45520E-08
14	+2.05722E-02	+3.96115E-04	+1.47601E-08
15	+9.48992E-02	+7.65308E-04	+8.70536E-09
16	+1.40532E-01	+3.90357E-04	+1.11808E-08
17	+8.42751E-02	+6.66285E-04	+5.36067E-07
18	+1.65360E-02	+4.60802E-03	+5.45902E-08
19	+1.84787E-01	+2.64671E-04	+4.88485E-08
20	+1.70551E-01	+6.96129E-04	+1.17654E-08
21	+4.60069E-02	+8.37999E-05	+1.36076E-06
22	+1.60326E-01	+8.44705E-04	+6.92502E-09
23	+1.60591E-01	+8.72990E-04	+9.15675E-10
24	+8.55547E-02	+3.19504E-04	+2.95598E-07
25	+1.04292E-01	+1.37655E-04	+3.06659E-07

Table A2. (continued)

Unit i	$n_{i,a}$	$n_{i,b}$	$n_{i,d}$
26	+9.44293E-02	+6.55928E-04	+9.20563E-09
27	+8.37546E-02	+2.99681E-04	+5.90079E-07
28	+4.77134E-03	+1.88912E-03	+1.02139E-09
29	+2.14421E-02	+4.34053E-05	+4.09963E-08
30	+4.29493E-03	+3.45599E-04	+3.24730E-08
31	+8.30595E-03	+2.25130E-04	+3.57065E-08
32	+1.19256E-03	+3.66499E-04	+3.33712E-08
33	+1.85846E-01	+3.05679E-04	+1.33385E-08
34	+2.30105E-01	+6.61254E-06	+1.47647E-08
35	+2.35258E-03	+1.40116E-04	+1.68896E-06
36	+5.02378E-03	+3.94963E-05	+1.84011E-06
37	+2.90611E-02	+1.06547E-03	+1.57681E-05
38	+5.04757E-02	+9.69020E-05	+1.29217E-06
39	+9.89863E-02	+7.02300E-04	+7.48588E-08
40	+1.04568E-01	+9.00730E-04	+6.19030E-09
41	+5.25221E-02	+5.27164E-05	+2.66437E-07
42	+5.17828E-02	+1.94233E-05	+2.75373E-07
43	+1.93665E-02	+1.73604E-03	+3.70616E-09
44	+8.26053E-02	+1.50449E-03	+2.09695E-09
45	+1.43912E-01	+9.69083E-04	+6.12967E-09
46	+1.00936E-01	+1.36380E-03	+3.25676E-09
47	+2.32844E-01	+1.05089E-03	+2.18368E-09
48	+2.29218E-01	+1.05034E-03	+2.66790E-09
49	+6.94335E-02	+1.02911E-04	+1.79603E-08
50	+2.99670E-02	+5.14825E-04	+1.26804E-08

Table A3. Unit SO_2 Coefficients

Unit i	$s_{i,a}$	$s_{i,b}$	$s_{i,d}$
1	+7.91851E-02	+1.90105E-03	+5.21790E-08
2	+1.02690E-01	+1.72277E-03	+1.71238E-07
3	+1.69823E-02	+2.05046E-03	+1.48311E-08
4	+2.35063E-02	+3.41997E-03	+7.14286E-09
5	+1.59058E-02	+3.28595E-03	+4.11537E-08
6	+8.53788E-03	+3.45493E-03	+1.00488E-10
7	+2.32691E-02	+3.23966E-03	+1.70699E-09
8	+9.80545E-02	+1.68909E-03	+5.51173E-08
9	+6.02560E-02	+1.46630E-03	+1.47425E-08
10	+1.58906E-01	+1.45271E-03	+4.21536E-08
11	+2.27460E-02	+2.24567E-03	+1.23512E-09
12	+3.89329E-02	+1.94001E-03	+5.76506E-09
13	+4.11345E-02	+2.00860E-03	+4.89124E-09
14	+4.94254E-02	+1.89898E-03	+5.96842E-09
15	+4.85918E-02	+3.97373E-03	+2.25878E-10
16	+8.61091E-02	+3.68128E-03	+2.28178E-09
17	+2.73809E-02	+2.03488E-03	+2.53896E-07
18	+5.88152E-02	+1.34759E-03	+3.01269E-07
19	+1.42619E-01	+4.43038E-04	+2.45763E-07
20	+1.36455E-01	+3.30122E-04	+2.46778E-07
21	+1.77293E-02	+1.99772E-03	+5.90502E-07
22	+1.23793E-01	+4.12691E-04	+2.56893E-07
23	+1.43350E-01	+3.53743E-04	+2.46867E-07
24	+1.73808E-01	+2.28768E-04	+1.65948E-07
25	+1.75923E-01	+3.21057E-04	+1.54414E-07

Table A3. (continued)

Unit i	$s_{i,a}$	$s_{i,b}$	$s_{i,d}$
26	+2.83925E-01	+2.33673E-03	+3.09898E-09
27	+5.39046E-03	+3.32613E-03	+1.20484E-07
28	+2.91246E-02	+3.64374E-03	+3.81014E-09
29	+6.92570E-02	+1.82733E-03	+1.52655E-08
30	+4.37481E-02	+1.82745E-03	+1.88576E-08
31	+4.57249E-02	+1.94047E-03	+1.86298E-08
32	+4.83955E-02	+1.85882E-03	+1.90948E-08
33	+1.38529E-01	+4.33978E-03	+3.66920E-09
34	+1.38685E-01	+4.40710E-03	+3.09346E-09
35	+9.68303E-03	+4.47554E-04	+1.34297E-06
36	+1.79112E-03	+8.81582E-04	+1.14582E-06
37	+9.36543E-03	+3.03407E-03	+2.49427E-06
38	+2.10878E-02	+1.59550E-03	+7.52400E-07
39	+7.45687E-04	+2.40692E-03	+3.38840E-07
40	+1.48958E-02	+1.77513E-03	+5.25500E-07
41	+5.42762E-04	+2.94484E-03	+1.27650E-07
42	+5.79611E-03	+2.77693E-03	+1.50110E-07
43	+2.66250E-02	+3.76346E-03	+2.20546E-09
44	+5.68566E-02	+2.35094E-03	+7.46690E-09
45	+1.55310E-01	+4.52378E-03	+4.76632E-10
46	+8.09570E-02	+4.65652E-03	+1.78323E-09
47	+8.62247E-02	+2.18600E-03	+4.47382E-08
48	+1.29880E-02	+3.67711E-03	+3.86648E-09
49	+5.40370E-02	+3.46366E-03	+2.38386E-09
50	+3.46734E-02	+3.57775E-03	+2.17391E-09

Table A4. Unit Modeling Data

Unit i	P_i^{Mn}	P_i^{Mx}	U_i
1	20.00	100.00	1.294
2	20.00	100.00	1.294
3	20.00	100.00	1.294
4	30.00	105.00	1.248
5	30.00	105.00	1.248
6	35.00	175.00	1.248
7	35.00	175.00	1.248
8	20.00	80.00	1.307
9	40.00	180.00	1.307
10	40.00	180.00	1.307
11	45.00	235.00	1.321
12	45.00	235.00	1.321
13	45.00	235.00	1.321
14	45.00	235.00	1.321
15	150.00	350.00	1.321
16	150.00	350.00	1.321
17	20.00	80.00	1.334
18	20.00	80.00	1.334
19	38.00	110.00	1.334
20	36.00	110.00	1.334
21	18.00	53.00	1.278
22	35.00	110.00	1.278
23	35.00	110.00	1.278
24	50.00	120.00	1.278
25	50.00	120.00	1.278

Table A4. (continued)

Unit i	P_i^{Mn}	P_i^{Mx}	U_i
26	175.00	375.00	1.278
27	25.00	80.00	1.275
28	80.00	175.00	1.275
29	75.00	180.00	1.275
30	75.00	180.00	1.275
31	75.00	180.00	1.354
32	75.00	180.00	1.354
33	125.00	330.00	1.354
34	125.00	330.00	1.354
35	30.50	52.00	1.295
36	30.50	52.00	1.295
37	8.00	21.00	1.295
38	18.00	53.00	1.295
39	19.50	65.00	1.235
40	19.50	65.00	1.235
41	27.00	90.00	1.235
42	27.00	90.00	1.235
43	75.00	175.00	1.336
44	60.00	190.00	1.336
45	90.00	350.00	1.336
46	90.00	350.00	1.336
47	60.00	150.00	1.353
48	60.00	150.00	1.353
49	77.00	252.00	1.353
50	77.00	252.00	1.353

Table A5. Unit Commitment Schedule

Hour	Units (1 through 50)
1	11111111111111111111111111111111111111111111111111
2	11111111111111111111111111111111111111111111111111
3	11111111111111111111111111111111111111111111111111
4	11111111111111111111111111111111111111111111111111
5	11111111111111111111111111111111111111111111111111
6	11111111111111111111111111111111111111111111111111
7	11111111111111111111111111111111111111111111111111
8	11111111111111111111111111111111111111111111111111
9	11111111111111111111111111111111111111111111111111
10	11111111111111111111111111111111111111111111111111
11	11111111111111111111111111111111111111111111111111
12	11111111111111111111111111111111111111111111111111
13	11111111111111111111111111111111111111111111111111
14	11111111111111111111111111111111111111111111111111
15	11111111111111111111111111111111111111111111111111
16	11111111111111111111111111111111111111111111111111
17	11111111111111111111111111111111111111111111111111
18	11111111111111111111111111111111111111111111111111
19	11111111111111111111111111111111111111111111111111
20	11111111111111111111111111111111111111111111111111
21	11111111111111111111111111111111111111111111111111
22	11111111111111111111111111111111111111111111111111
23	11111111111111111111111111111111111111111111111111
24	11111111111111111111111111111111111111111111111111
25	11111111111111111111111111111111111111111111111111
26	11111111111111111111111111111111111111111111111111
27	11111111111111111111111111111111111111111111111111
28	11111111111111111111111111111111111111111111111111
29	11111111111111111111111111111111111111111111111111
30	11111111111111111111111111111111111111111111111111
31	11111111111111111111111111111111111111111111111111
32	11111111111111111111111111111111111111111111111111
33	11111111111111111111111111111111111111111111111111
34	11111111111111111111111111111111111111111111111111
35	11111111111111111111111111111111111111111111111111
36	11111111111111111111111111111111111111111111111111
37	11111111111111111111111111111111111111111111111111
38	11111111111111111111111111111111111111111111111111

Table A5. (continued)

Hour	Units (1 through 50)
39	11111111111111111111111111111111111111111111111111
40	11111111111111111111111111111111111111111111111111
41	11111111111111111111111111111111111111111111111111
42	11111111111111111111111111111111111111111111111111
43	11111111111111111111111111111111111111111111111111
44	11111111111111111111111111111111111111111111111111
45	11111111111111111111111111111111111111111111111111
46	11111111111111111111111111111111111111111111111111
47	11111111111111111111111111111111111111111111111111
48	11111111111111111111111111111111111111111111111111
49	11111111111111111111111111111111111111111111111111
50	11111111111111111111111111111111111111111111111111
51	11111111111111111111111111111111111111111111111111
52	11111111111111111111111111111111111111111111111111
53	11111111111111111111111111111111111111111111111111
54	11111111111111111111111111111111111111111111111111
55	11111111111111111111111111111111111111111111111111
56	11111111111111111111111111111111111111111111111111
57	11111111111111111111111111111111111111111111111111
58	11111111111111111111111111111111111111111111111111
59	11111111111111111111111111111111111111111111111111
60	11111111111111111111111111111111111111111111111111
61	11111111111111111111111111111111111111111111111111
62	11111111111111111111111111111111111111111111111111
63	11111111111111111111111111111111111111111111111111
64	11111111111111111111111111111111111111111111111111
65	11111111111111111111111111111111111111111111111111
66	11111111111111111111111111111111111111111111111111
67	11111111111111111111111111111111111111111111111111
68	11111111111111111111111111111111111111111111111111
69	11111111111111111111111111111111111111111111111111
70	11111111111111111111111111111111111111111111111111
71	11111111111111111111111111111111111111111111111111
72	11111111111111111111111111111111111111111111111111
73	11111111111111111111111111111111111111111111111111
74	11111111111111111111111111111111111111111111111111
75	11111111111111111111111111111111111111111111111111
76	11111111111111111111111111111111111111111111111111

Table A5. (continued)

Hour	Units (1 through 50)
77	11111111111111111111111111111111111111111111111111
78	11111111111111111111111111111111111111111111111111
79	11111111111111111111111111111111111111111111111111
80	11111111111111111111111111111111111111111111111111
81	11111111111111111111111111111111111111111111111111
82	11111111111111111111111111111111111111111111111111
83	11111111111111111111111111111111111111111111111111
84	11111111111111111111111111111111111111111111111111
85	11111111111111111111111111111111111111111111111111
86	11111111111111111111111111111111111111111111111111
87	11111111111111111111111111111111111111111111111111
88	11111111111111111111111111111111111111111111111111
89	11111111111111111111111111111111111111111111111111
90	11111111111111111111111111111111111111111111111111
91	11111111111111111111111111111111111111111111111111
92	11111111111111111111111111111111111111111111111111
93	11111111111111111111111111111111111111111111111111
94	11111111111111111111111111111111111111111111111111
95	11111111111111111111111111111111111111111111111111
96	11111111111111111111111111111111111111111111111111
97	11111111111111111111111111111111111111111111111111
98	11111111111111111111111111111111111111111111111111
99	11111111111111111111111111111111111111111111111111
100	11111111111111111111111111111111111111111111111111
101	11111111111111111111111111111111111111111111111111
102	11111111111111111111111111111111111111111111111111
103	11111111111111111111111111111111111111111111111111
104	11111111111111111111111111111111111111111111111111
105	11111111111111111111111111111111111111111111111111
106	11111111111111111111111111111111111111111111111111
107	11111111111111111111111111111111111111111111111111
108	11111111111111111111111111111111111111111111111111
109	11111111111111111111111111111111111111111111111111
110	11111111111111111111111111111111111111111111111111
111	11111111111111111111111111111111111111111111111111
112	11111111111111111111111111111111111111111111111111
113	11111111111111111111111111111111111111111111111111
114	11111111111111111111111111111111111111111111111111

Table A5. (continued)

Hour	Units (1 through 50)
115	11111111111111111111111111111111111111111111111111
116	11111111111111111111111111111111111111111111111111
117	11111111111111111111111111111111111111111111111111
118	11111111111111111111111111111111111111111111111111
119	11111111111111111111111111111111111111111111111111
120	11111111111111111111111111111111111111111111111111
121	11111111111111111100011111011111110000000011111111
122	11111111111111111100011111011111110000000011111111
123	11111111111111111100011111011111110000000011111111
124	11111111111111111100011111011111110000000011111111
125	11111111111111111100011111011111110000000011111111
126	11111111111111111100011111011111110000000011111111
127	11111111111111111100011111011111110000000011111111
128	11111111111111111100011111011111110000000011111111
129	11111111111111111100011111011111110000000011111111
130	11111111111111111100011111011111110000000011111111
131	11111111111111111100011111011111110000000011111111
132	11111111111111111100011111011111110000000011111111
133	11111111111111111100011111011111110000000011111111
134	11111111111111111100011111011111110000000011111111
135	11111111111111111100011111011111110000000011111111
136	11111111111111111100011111011111110000000011111111
137	11111111111111111100011111011111110000000011111111
138	11111111111111111100011111011111110000000011111111
139	11111111111111111100011111011111110000000011111111
140	11111111111111111100011111011111110000000011111111
141	11111111111111111100011111011111110000000011111111
142	11111111111111111100011111011111110000000011111111
143	11111111111111111100011111011111110000000011111111
144	11111111111111111100011111011111110000000011111111
145	00000000111111100000000001001100110000000011110011
146	00000000111111100000000001001100110000000011110011
147	00000000111111100000000001001100110000000011110011
148	00000000111111100000000001001100110000000011110011
149	00000000111111100000000001001100110000000011110011
150	00000000111111100000000001001100110000000011110011
151	00000000111111100000000001001100110000000011110011
152	00000000111111100000000001001100110000000011110011

Table A5. (continued)

Hour	Units (1 through 50)
153	00000000111111110000000001001100110000000011110011
154	00000000111111110000000001001100110000000011110011
155	00000000111111110000000001001100110000000011110011
156	00000000111111110000000001001100110000000011110011
157	00000000111111110000000001001100110000000011110011
158	00000000111111110000000001001100110000000011110011
159	00000000111111110000000001001100110000000011110011
160	00000000111111110000000001001100110000000011110011
161	00000000111111110000000001001100110000000011110011
162	00000000111111110000000001001100110000000011110011
163	11111111111111111100011110111111110000000011111111
164	11111111111111111100011110111111110000000011111111
165	11111111111111111100011110111111110000000011111111
166	11111111111111111100011110111111110000000011111111
167	11111111111111111100011110111111110000000011111111
168	11111111111111111100011110111111110000000011111111

Table A6. Configuration of Power Plants and Fuel Groups

Power Plant	Generating Units	Fuel Group	Generating Units
1	1 - 3	1	1 - 3
2	4 - 7	2	4 - 7
3	8 - 10	3	8 - 10
4	11 - 16	4	11 - 16
5	17 - 20	5	17 - 20
6	21 - 26	6	21 - 26
7	27 - 30	7	27 - 30
8	31 - 34	8	31 - 32
9	35 - 38	9	33 - 34
10	39 - 42	10	35 - 42
11	43 - 46	11	43 - 46
12	47 - 50	12	47 - 50

Table A7. Load Values

Hour	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7
1	2976	4118	4290	4078	3861	3003	2145
2	3036	3867	4026	3828	3623	2818	2013
3	3095	3484	3630	3451	3267	2541	1815
4	3154	3293	3432	3260	3088	2402	1716
5	3399	3550	3696	3511	3326	2587	1848
6	3828	3993	4158	3953	3742	2910	2079
7	4131	4309	4488	4263	4039	3141	2244
8	4369	4560	4752	4514	4276	3326	2376
9	4613	4818	5016	4765	4514	3511	2508
10	4857	5068	5280	5016	4752	3696	2640
11	4976	5194	5412	5141	4870	3788	2706
12	4672	4877	5082	4831	4573	3557	2541
13	4917	5134	5346	5082	4811	3742	2673
14	5161	5385	5610	5326	5049	3927	2805
15	5405	5636	5874	5583	5286	4111	2937
16	5649	5893	6138	5834	5524	4296	3069
17	5887	6144	6402	6078	5761	4481	3201
18	6072	6336	6600	6270	5940	4620	3300
19	5827	6085	6336	6019	5702	4435	3168
20	5346	5577	5808	5517	5227	4065	3036
21	5042	5260	5478	5200	4930	3834	2871
22	4798	5002	5214	4956	4692	3649	2772
23	4494	4686	4884	4639	4395	3418	2838
24	4191	4369	4554	4323	4098	3187	2904

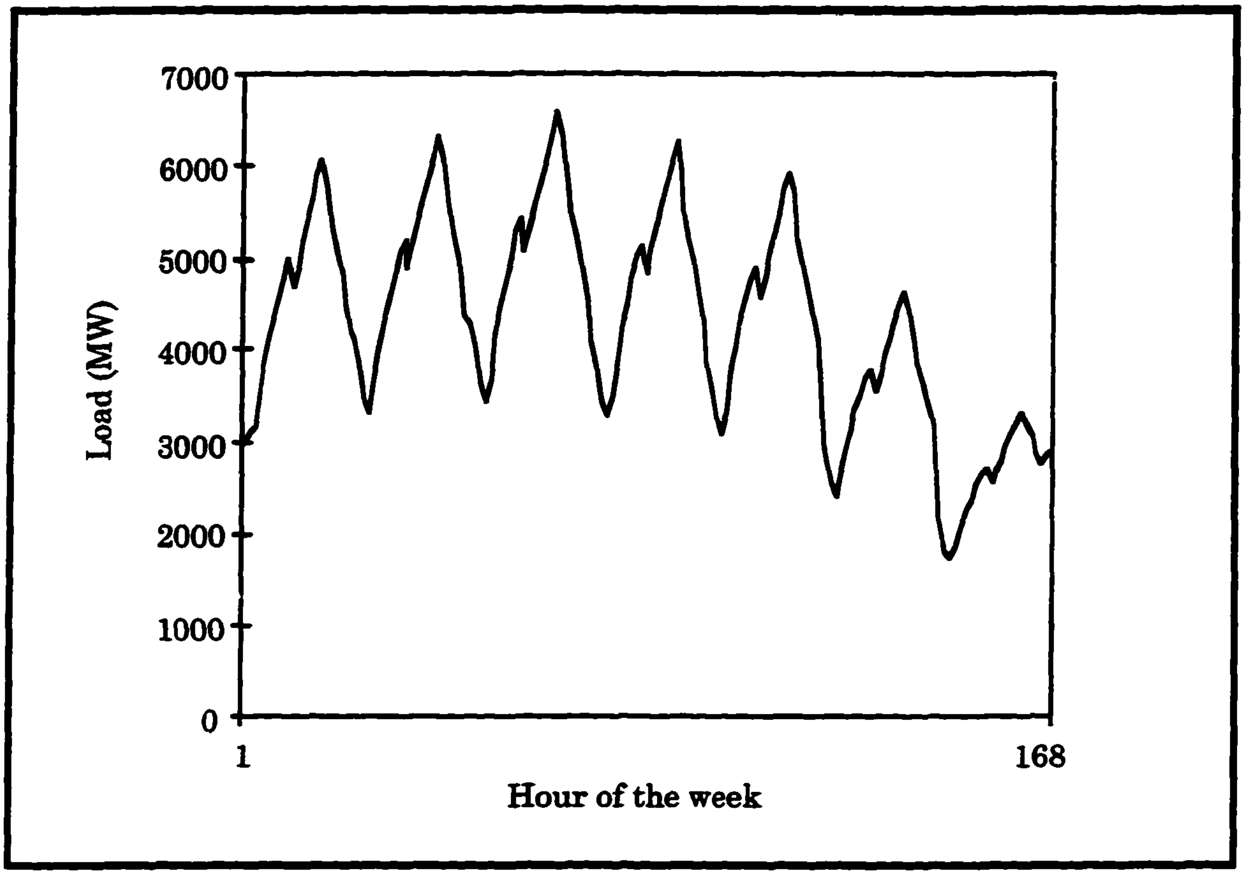

Figure A1. Load Profile

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