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Economic efficiencies of the energy flows from the primary resource suppliers to the electric load centers

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ABSTRACT

The economic efficiency of the electric energy system depends not only on the performance of the electric generation and transmission subsystems, but also on the ability to produce and transport the various forms of primary energy, particularly coal and natural gas. However, electric power systems have traditionally been developed and operated without a conscious awareness of the energy system-wide implications, namely the consideration of the integrated dynamics with the fuel markets and infrastructures. This has been partly due to the difficulty of formulating models capable of analyzing the large-scale, complex, time-dependent, and highly interconnected behavior of the integrated energy system. In this dissertation, a novel approach for studying the movements of coal, natural gas, and electricity in an integrated fashion is presented. Conceptually, the model developed is a simplified representation of the national infrastructures, structured as a generalized, multiperiod network composed of nodes and arcs. Under this formulation, fuel supply and electricity demand nodes are connected via a transportation network and the model is solved for the most efficient allocation of quantities and corresponding prices for the mutual benefits of all. The synergistic action of economic, physical, and environmental constraints produces the optimal pattern of energy flows. Key data elements are derived from various publicly available sources, including publications from the Energy Information Administration, survey forms administered by the Federal Energy Regulatory Commission, and databases maintained by the Environmental Protection Agency. The results of different test cases are analyzed to demonstrate that the decentralized level of decision-making combined with imperfect competition may be preventing the realization of potential cost savings. An overall optimization at the national level shows that there are opportunities to better utilize low cost generators, curtailing usage of higher cost units and increasing electric power trade, which would ultimately allow customers to benefit from lower electricity prices. In summary, the model developed is a simulation tool that helps build a better understanding of the complex dynamics and interdependencies of the coal, natural gas, and electricity networks. It enables public and private decision makers to carry out comprehensive analyses of a wide range of

issues related to the energy sector, such as strategic planning, economic impact assessment, and the effects of different regulatory regimes.

CHAPTER 1. INTRODUCTION

1.1 MOTIVATION

The economic and physical integrity of the electric energy system depends not only on the performance of electric generation and transmission subsystems, but also on the ability to produce and transport the various forms of raw energy[1] that are used to generate electricity. These raw energy forms include fossil fuels (i.e., coal[2], natural gas, and petroleum[3]), nuclear, hydro, and others (e.g., wood, waste, geothermal, wind, and solar). Figure 1.1 depicts the shares of electricity net generation in the United States, by energy source, for the years 2002 and 2004. The totals correspond to 3,858 and 3,970 billion kilowatthours, respectively [1].

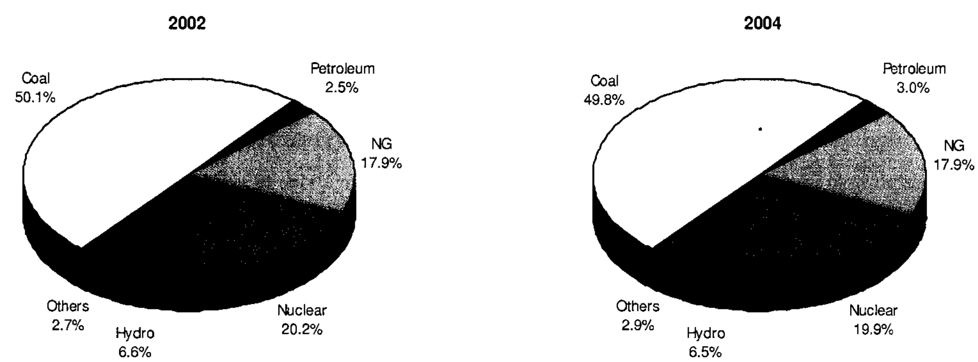

Figure 1.1 – Shares of electricity net generation, by energy source, for the year 2002 (left) and 2004 (right)

The pie charts show that, in terms of electricity net generation, the mix of generation technologies has not changed significantly from 2002 to 2004. They also show that the generation portfolio is dominated by fossil fuels, which are responsible for about 70% of the total electricity net generation. Coal and natural gas are the most important fossil fuels, being

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[1] Raw energy: Any energy embodied in natural resources (e.g., coal, wood, sunlight, water) that has not yet been converted into electric energy. The expression "raw energy" and "primary energy" will be used interchangeably throughout this document.
[2] Coal: Includes anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[3] Petroleum: Includes distillate fuel oil, residual fuel oil, jet fuel, kerosene, petroleum coke, and waste oil.

responsible for roughly half and 18% of the total electricity net generation, respectively.

Most medium term electric energy models designed to address various issues associated with the operation of electric power systems (e.g., economic performance and reliability risk analysis), exclude the primary energy flows from their formulation, or simply represent them as exogenous variables that follow an assumed behavior. This dissertation presents a multiperiod generalized network flow model of the U.S. integrated electric energy system where the production, transportation, and delivery of coal and natural gas to the power plants are endogenously represented for a medium term analysis (several months to 2-3 years). The model is used to explore interdependencies between the coal, natural gas, and electricity subsystems and analyze the economic performance of the overall energy flows. Since the model incorporates sulfur dioxide emissions restriction, it is also used to analyze the impact of this policy instrument on the integrated energy system. The schedules of electricity generated from nuclear energy and renewable energy forms are represented as direct inputs into the electric transmission system, due in part to the lack of influence that they have on the total costs of compliance with emissions standards. Furthermore, despite the relative importance of electricity generation from nuclear energy (roughly 20%), this energy form is associated with large time constants that translate into slow dynamics, and therefore is assumed not to influence the medium term analysis performed herein. On the other hand, renewable energies have unique characteristics and most of them cannot be transported as a raw fuel (e.g., wind and sunlight) and therefore represent no energy movement alternative to electric transmission in the way that coal and natural gas do. As regards to oil, it comprises a relatively small percentage of electric fuel supply, which justifies the exclusion of its complex dynamics from an endogenous representation.

The two primary energy forms incorporated in the model (coal and natural gas), together with the electric energy subsystem, have the common characteristic that they are moved via a network transportation system from their sources of production to where they are used. Coal is transported by trains along most of the major nation's railroads, over the inland waterway system by barge and towboat, along the coasts and over the Great Lakes by collier, and overland by truck, coal slurry[1] pipeline, and conveyer; gas is moved by pipelines; and electricity is transported by transmission lines. Furthermore, they all share another important attribute, which is the utilization of financial markets where these energy forms are traded as commodities.

A major reason that motivates this research work is the lack of a model where all actors involved in the integrated energy system are fully represented. Although economic and physical performances of individual subsystems are well studied and understood, there has been little effort to study its global characteristics. This has been partly due to the difficulty of formulating models capable of analyzing the integrated system while accounting for characteristics unique to each subsystem. Consequently, each energy subsystem supports specific procedures and strategies according to their own value system (i.e., economic, technical, political, and environmental context), which may be fragmentary because they are missing the necessary consolidation in global actions or alternative strategies for an efficient overall operation.

Today's industry climate motivates a more integrated study of the energy system. First, as the electric power industry becomes more competitive, economic performance of electricity delivery is intensely scrutinized from a national perspective, with electricity delivery price as a key metric. Customers and regulators are questioning electricity markets in which prices are significantly higher than those in other parts of the country, resulting in heavy pressure to identify means to gain economic efficiencies (lower prices) without seriously diminishing the reliability of the system. Second, the percentage of fuel purchased on the spot market[2] has been increasing with a corresponding decrease in the percentage of

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1 Coal slurry: A mixture of half pulverized coal and half water that is pumped through a pipeline. The only coal slurry operation in the country is the Black Mesa pipeline, which moves coal from the Peabody Western Coal Company's Black Mesa mine located in the northeastern Arizona to the Mohave Generating Station located in southern Nevada.

2 Spot market: Any of a number of venues in which transactions are being made continuously or at very frequent intervals. Typically, the phrase refers to a lightly or non-regulated market in which the prices, amounts, duration, and firmness of the purchases and sales are publicly known, at least shortly after the transaction is completed, if not simultaneously. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low prices.

fuel purchased under long term contracts[1]. In addition, long term contracts have become shorter in duration, as electric power generators try to pass market risks on to primary energy suppliers (producers and carriers) [2]. This increases concern on the part of generation owners that they may be more vulnerable to short or medium term contingencies in fuel supply. Third, there exists increasing awareness of the environmental problems caused by the electric energy sector, which leads to the intensification of measures to internalize the externalities[2] associated with electric power generation. In particular, the passage of the Clean Air Act Amendments (CAAA) of 1990[3] [3] forced electric generators to reduce their emissions of sulfur dioxide (SO_2) through the implementation of an innovative tradable permit system[4]. Utilities are endowed with considerable operational flexibility since it is the total quantity of emissions that matters and a utility can achieve its target level through emission controls, fuel switching, conservation programs, or by buying allowances. Depending on the compliance strategies adopted, the impacts of the SO_2 regulations can go beyond the electric power subsystem and affect the energy flows of the fuel networks. Finally, the perception has grown that the national economy relies on a complex, multi-scale, distributed, and highly interdependent energy infrastructure, which is exposed to high-severity cascading failures with widespread consequences as result of intentional acts.

In 1998, the President of the United States issued a directive calling for a national effort to assure the security of the increasingly vulnerable and interconnected infrastructures. In this context, complex networked systems such as electric power grids, oil and gas pipelines, transportation networks, telecommunications, and financial systems are defined as

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[1] Long term contracts: Any of a number of venues in which utilities negotiate agreements to acquire fuel for periods of one or more years. These contracts are usually written and may have stipulations, such as the minimum and maximum limits on the quantity of fuel delivered over a specified time period. Contract prices reflect market conditions at the time the contract is negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation causes, but, in general, contract prices do not fluctuate widely.

[2] Internalizing externalities: Create the social conditions where, in this case, the damages from electric power generation are taken into account by those who produce these effects. These social conditions can be created by government regulations, bargaining between private parties, or other policy and institutional arrangements.

[3] The 1990 Clean Air Act Amendments is Public Law 101-549.

[4] Tradable permit system: Along with a cap on overall annual emissions, the SO_2 allowance market gives the electric utilities the opportunity to trade the rights to emit SO_2 rather than forcing them to install SO_2 abatement technology or emit at a uniform rate. The idea is that, by equating marginal abatement costs among power plants, trading should limit emissions at a lower cost than the traditional command-and-control approach.

critical infrastructures. The interconnected and interdependent nature of these infrastructures makes them vulnerable to cascading failures, i.e., the propagation of disruption from one system to the other, with possible catastrophic consequences. To better manage and prevent these disturbances, a basic understanding of the true system dynamics is required. Nonetheless, electric power system developments are traditionally done without a conscious awareness of the economic and physical interactions with other infrastructures on an energy system-wide analysis.

Moreover, electricity movements in the electric power subsystem are occurring on a much wider scale than they have ever before, resulting in new and diverse flow patterns. These movements result from marketplace response to geographical variation in energy prices. However, decisions to buy or sell bulk electrical energy are typically made without significant consideration of using alternative energy transportation modes, that is, using railroads or barges for coal and pipelines for gas instead of electric transmission for electricity. Likewise, decisions to buy or sell coal or gas are typically made without significant consideration of alternative energy transportation using electric transmission. For example, coal can be moved by railroad from Wyoming to a Chicago coal-fired power plant or from Wyoming to an Omaha power plant and then by electric transmission lines to Chicago; or used at a West Virginia minemouth plant and moved by electric transmission lines to Chicago, or moved by railroad from West Virginia to a power plant in Ohio or Indiana and then by electric transmission lines to Chicago. Likewise, gas could be moved via pipeline from Louisiana to a Chicago gas-fired power plant or from Louisiana to a St. Louis power plant and then by electric transmission lines to Chicago, or brought in by pipeline direct from Canada to Chicago. Clearly, there are a large number of feasible alternatives to satisfy electricity demands, and the most economic alternative varies with fuel production, transportation availability, environmental regulations, and prices.

1.2 OBJECTIVES

The general purpose of this research work is to evaluate the economic efficiencies of the energy flows in the integrated energy system, from the fossil fuel suppliers to the electric load centers. In this context, the energy flows are the movements of coal, natural gas, and electricity that result from operational decisions carried out in the electric power system. More specifically, the objectives are to:

- Identify the least cost flow patterns and compare them to existing flow patterns;
- Determine the extent to which SO_2 restrictions imposed on electricity generation affect the flow patterns and the operating costs of the energy system;
- Evaluate how the level of decentralization of the decision making processes affects the economic performance of the energy system.

To address these issues, a multiperiod generalized network flow model of the U.S. integrated energy system is developed. The model focuses on the economic interdependencies of the integrated system, in the sense that it represents multiple energy subsystems (electric, coal, and natural gas), along with a detailed characterization of their functionalities (supply, demand, storage, and transportation), within a single analytical framework that allows for their simultaneous study. The methodology includes the technological, economic, and environmental aspects of the different energy subsystems.

The integrated energy model developed can be used to identify more economically efficient bulk energy transportation routes and associated transportation modes that could be used to move energy from the coal and natural gas suppliers to the electric load centers. These patterns of energy movements, if utilized, would reflect a reduced rate of energy consumption and/or lower total operating costs (including environmental costs for compliance with the SO_2 tradable permit system), which would in turn bring benefits to the society at large and effectively contribute to enhance national competitiveness.

Although no single entity has full control of these complex interactive energy networks, the optimization model described herein implicitly assumes that a centralized decision authority exists and that it benefits from access to complete information. Therefore, the model serves as a benchmark and the least cost energy flow pattern solution represents an ideal case that is useful in comparison to reality in order to assess what kind of economic improvements are thinkable, relative to today's energy movement patterns. For example, the model serves to examine how the integrated energy system responds to different fuel prices or changes in environmental requirements. Furthermore, it serves to evaluate how decentralization of decision making (which is reality) affects the system-wide economic performance. It other words, it serves to analyze whether any central authority is required, or even desirable, or whether the current movement towards deregulation and competition can, by itself, optimize the efficiency and security of network operations for the mutual benefit of all. In addition, since all functionalities of the energy system are represented, the nodal prices obtained as a by-product of the optimization procedure provide a means to assess the interdependencies between the fuel subsystems and the electric subsystem and identify the most efficient investment strategies.

The developed model is a simulation tool that helps build a basic understanding of the complex dynamics of the integrated energy system. It enables energy companies to carry out comprehensive analyses of their investments as well as overall optimization of their energy supply systems. Governmental bodies may also utilize the developed techniques to do comprehensive scenario studies with respect to environmental impacts and consequences of different regulating regimes. In summary, an important impact of the work is to motivate the key decision makers (e.g., generation owners, fuel suppliers, governmental agencies, etc.) to create the necessary conditions and incentive mechanisms so that more efficient flow patterns are utilized by overcoming informational, organizational, regulatory, and/or political barriers, by increasing link or production capacity, or by building new links or production facilities.

1.3 THESIS ORGANIZATION

Chapter 1 presents the reasons that motivated this research work and its objectives. Chapter 2 reviews the relevant literature about fuel scheduling and hydrothermal coordination, coal and natural gas optimization models, integrated energy models, and critical infrastructure interdependencies. Chapter 3 provides the rationale and the theoretical underpinnings of the modeling methodology chosen. The mathematical formulation and solution procedures are addressed in chapter 4. Chapter 5 contains a detailed discussion of the modeling assumptions of the integrated energy system. Chapter 6 provides a detailed description of the model structure and the complete procedure for obtaining the solution of the optimization problem and visualize the results. Results of three case studies are presented in chapter 7. Concluding remarks and directions for future work follow in chapter 8.

CHAPTER 2. LITERATURE REVIEW

2.1 FUEL SCHEDULING AND HYDROTHERMAL COORDINATION

There has been significant work in scheduling fuel deliveries and water resource usage in order to optimize electric energy production [4], [5]. An important development in [6] was the inclusion of emission constraints within the fuel scheduling problem of a particular electric power utility, and [7], [8] included uncertainties associated with coal available for purchase and sulfur content. The fuel scheduling and accounting functions proposed by [9] are of relevance for large natural gas consuming electric utilities, because it allows the avoidance of penalties that can be incurred for violating fuel contracts, by monitoring contract volumes and efficiently formulating the fuel usage plans for the next time periods. A linear programming technique is used in [10] with the objective to minimize the fuel costs associated with its purchase and storage, for a long-term optimization scheduling problem. In [11] a short-term fuel scheduling problem is solved using genetic algorithms and simulated annealing methods. The common denominator of all of these known fuel scheduling approaches is that they view the fuel system only in terms of contracts and associated penalties for possible violations. That is to say that there has been little effort to optimize the electric power system operations accounting for the fuel production, storage, and transportation costs and capabilities.

The hydrothermal coordination[1] problem requires solution of thermal unit commitments[2] and economic load dispatch[3] simultaneously with the hydro schedules, so that energy flow via water movement has been well integrated with the solution to the electric

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[1] Hydrothermal coordination: The hydrothermal coordination problem consists of determining the optimal amounts of hydro and thermal generation to be used during a scheduling period.

[2] Unit commitment: The unit commitment problem deals with the decision on which of the thermal units will be running or not during each hour of the scheduling period.

[3] Economic load dispatch: The economic load dispatch problem consists of finding the optimal allocation of power demand among the running thermal units, satisfying the power balance equations and the unit's operation constraints.

energy production problem [12]. Different approaches can be found in the literature to solve this problem. A successful hydrothermal optimization model for Pacific Gas and Electric [13] uses Lagrangian relaxation to solve a master problem that extends over a one week time horizon. Sub-problems are then solved for each plant using dynamic programming and for the river systems with a network flow algorithm. Heuristics ensure consistency between the various solutions. Lagrangian relaxation is an especially prominent approach for hydrothermal coordination [14], [15], [16], but many alternatives have also been applied, including network linear programming [17], mixed-integer programming [18], network flow programming [19], neural networks [20], and tabu search and Bender's decomposition [21], [22]. One advantage of the approach used in [13] is that its master problem/sub-problem structure allows subsystems to be integrated at a relatively high level while preserving more of their complexities.

2.2 COAL AND NATURAL GAS OPTIMIZATION MODELS

A number of optimization models for coal transportation can also be found in the literature, with some of the earlier ones including [23], [24], and [25]. Quadratic programming models with more sophisticated objective functions have also been developed [26] and applied to the spatial distribution of Appalachian coal [27]. Later models with additional refinements were published in [28], [29], and [30]. In [31], a generalized fuzzy linear programming model for solving the coal production scheduling problem is proposed. A theory for modeling and optimizing power plant coal inventories is presented in [32].

Gas well production optimization is a subject that has been addressed in several papers, such as [33] and more recently [34]. Linear and nonlinear techniques are used in [35] to find the optimal operating mode of a gas transmission system, in order to minimize costs (fuel usage and other operating and maintenance costs), while meeting contractual obligations of flow and pressure and emissions requirements. Reference [36] presents a methodology concerned with the optimization of a pipeline network (in terms of the pipe diameter and routing), involving linear programming and dynamic programming. While the simple structure of a network formulation cannot accurately capture the non-convexities describing the feasible set of values and costs of transporting gas through the pipeline network, more general formulations are available and have proven useful in appropriate contexts [37]. The effects of non-smooth and discontinuous behaviors are addressed by [38].

A major difference between all of the above cited literature and the approach presented in this dissertation is that the latter involves the development and study of an integrated, interdependent energy system model that includes a careful representation of the coal, gas, petroleum, and electric transportation networks, rather than the optimization of the performance of a single energy subsystem.

2.3 INTEGRATED ENERGY MODELS

A number of energy models have been developed for policy analysis, forecasting and to support global or local energy planning, namely the selection of appropriate strategies in regions experiencing rapid economic growth [39], [40]. In [41] a linear programming energy system model is utilized to analyze the optimal configuration of the energy transportation infrastructure in Asia and in [42] a multicriteria decision aid approach is developed to support regional energy planning and, in particular, to investigate the potential of renewable energy sources in a Greek island.

Examples of large scale energy models developed in the form of modular packages include EFOM, PRIMES, EMCAS, ENPEP, LEAP, MARKAL, MESAP, MESSAGE, NEMS, and RETscreen. The EFOM (Energy Flow Optimization Model) was developed as the supply part of the energy model complex of the European Commission DG XII [43]. To overcome the lack of market mechanisms and individual behavior, a series of research programs of the European Commission have been supporting the development of the PRIMES energy system model. PRIMES is a general purpose partial equilibrium model for energy supply and demand in the European Union member states. It is developed by the National Technical University of Athens. EMCAS (Electricity Markets Complex Adaptive Systems) has been developed by Argonne National Laboratory of the U.S. Department of Energy (DOE). The EMCAS is an agent-based modeling that is used to simulate various market operating rules [44]. It has been applied to the Illinois and Midwest transmission grid to analyze whether it would be able to support effective competition, and to investigate whether conditions could occur that would enable a company to exercise market power [45].

The ENPEP (ENergy and Power Evaluation Program) is a set of integrated energy, environmental, and economic analysis and planning tools that has been developed by the Argonne National Laboratory and other research institutions for the International Atomic Energy Agency [46]. The LEAP (Long-range Energy Alternatives Planning) system is an instrument for long term projections of supply/demand configurations and it is used to identify and evaluate policy and technology options. It has been developed by the Stockholm Environmental Institute of Boston, with support from several international organizations [47]. MARKAL (MARKet ALlocation) is a linear programming process-oriented bottom-up model for energy systems developed over a period of almost two decades by the Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA), and extensively used as a planning tool in a number of countries [48], [49]. MESAP (Modular Energy System Analysis and Planning) is a toolbox developed by the University of Stuttgart, Germany, for energy planning and environmental management at local, regional, and national level [50]. MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impact) is one of the six models that constitute the International Institute for Applied Systems Analysis' (Laxenburg, Austria) integrated modeling framework [51], [52]. NEMS (National Energy Modeling System) is a computer modeling system that produces a general equilibrium solution for energy supply and demand in the U.S. energy markets that has been developed by the Energy Information Administration (EIA), U.S. DOE [53], [54]. RETscreen (Renewable Energy Technology) was developed by the Renewable Energy Decision Support Center (CEDRL), Canada, to evaluate the energy production, life-cycle cost, and greenhouse gas emission reductions for various types of renewable energy technologies [55]. Reference [56] presents an overview of the main characteristics of some of these energy models.

An important consideration regarding many of the models discussed above is that they typically tend to be highly resource intensive, both in terms of expertise requirements to develop the model and support the underlying data and in terms of execution time and other computational resource requirements, reflecting the highly complex algorithmic and programming routines. In addition, and although these models integrate different energy systems in a modular form, none of them was designed to illustrate the effects that different energy transportation schemes (different energy flow patterns) have on the overall operating costs, which is an underlying objective of this research work. For regional planning purposes, however, there have been several studies performed to support the decision among alternative strategies, on a site-specific basis. An example is a case study described in [57], where a comparative analysis is performed to decide between the transport of coal by rail from Wyoming to an electric power plant in Texas and the generation of electricity near the minemouth with subsequent transport via transmission lines to the Texas customers. The comparison of long-distance energy transport systems is also the subject addressed in [58], where a framework for environmental life-cycle assessment is presented.

In general, integrated energy models are developed to suit the needs that policy makers and planners in the public and private sector have to understand the interplay between the macro-economy and energy use. They are typically designed to generate forecasts of future energy related activities under alternative scenarios, to provide a framework for analyzing the potential impact of energy and/or environmental policy changes on the different economic sectors, and to support private decision makers in their investment strategies. These models usually focus on a long term planning horizon (more than 10 years) and their underlying methodology is based on econometric concepts, macro-economic approaches, or market equilibrium models used to study and forecast the energy sector behavior as part of the overall economy and focus on interrelations between the energy sector and the rest of the economy. Conversely, the model proposed herein addresses a medium term operational horizon (several months to 2-3 years) and follows an optimization methodology that is used to optimize the movements of the energy that is ultimately used in the form of electricity, under given economic, technological, and environmental constraints. In contrast with a top-down approach that evaluates a broad equilibrium framework from aggregated economic variables, the bottom-up model described in this dissertation captures the physical restriction of the coal, natural gas, and electricity flows in an engineering sense. In addition, due to the typical complexity and high proprietary costs of existing integrated energy models, they are not readily available to the research community. Consequently, many opportunities exist to enrich this field of research and the rather limited technical literature and information available in the public domain.

2.4 CRITICAL INFRASTRUCTURE INTERDEPENDENCIES

Although to date relatively little effort and few resources have been devoted to understand and analyze the interdependencies among the complex and highly interconnected network of critical infrastructures of which electric power grids are a part, a few research initiatives have been taken and are worth mentioned. In an attempt to facilitate interdependencies research, a taxonomy for the types of interdependencies, infrastructure environment, coupling and response behavior, infrastructure characteristics, types of failures, and state of operations was proposed in [59]. In [60], the results of an investigation into the information systems used by four critical infrastructure applications (banking and finance, electric power, rail transportation, and air traffic control) are presented. The restoration of services in interdependent infrastructure systems and an assessment of vulnerabilities are the focuses of [61] and [62], respectively. In 2001, the National Petroleum Council produced a report with suggested actions for identifying and reducing infrastructure vulnerabilities within the oil and natural gas industry sector [63]. In a recent study addressing the interdependency of gas and electricity, a security constrained unit commitment is used to analyze the short-time impact of natural gas prices on power generation scheduling [64]. Sandia National Laboratories have initiated a research program on Energy and Infrastructure Assurance (formerly called Critical Infrastructure Surety), where they address the safety, security, and reliability of the energy supply and distribution infrastructures, including electric grid reliability, gas pipeline safety and integrity, and fossil energy supply enhancements [65]. In addition, a joint initiative on Complex Interactive Networks/Systems has been implemented by the Electric Power Research Institute (EPRI) and the U.S. Department of Defense (DoD), with the objective of developing methodologies for robust distributed control of heterogeneous, widely dispersed, yet interconnected systems, techniques for exploring interactive networked systems at the micro and macro levels, tools to prevent/ameliorate cascading effects through and between network, and tools/techniques that enable large-scale and interconnected national infrastructures to self-stabilize, self-optimize, and self-heal [66].

CHAPTER 3. MODELING APPROACH

3.1 OVERVIEW

Figure 3.1 represents the different components that comprise the integrated energy system, as defined in the context of this study. This characterizes a broad view of energy systems as the electric, natural gas, and coal subsystems, noting the fact that each of these subsystems depends on the integrated operation of a physical infrastructure together with a market, and noting the strong coupling within and between the different energy subsystems. As seen in [67] and [68], the different energy subsystems are highly coupled, and the security and economic prosperity of the nation depend on the way these complex and interdependent energy infrastructures operate. This coupling largely occurs through price and quantity of the energy flowing from one subsystem to another.

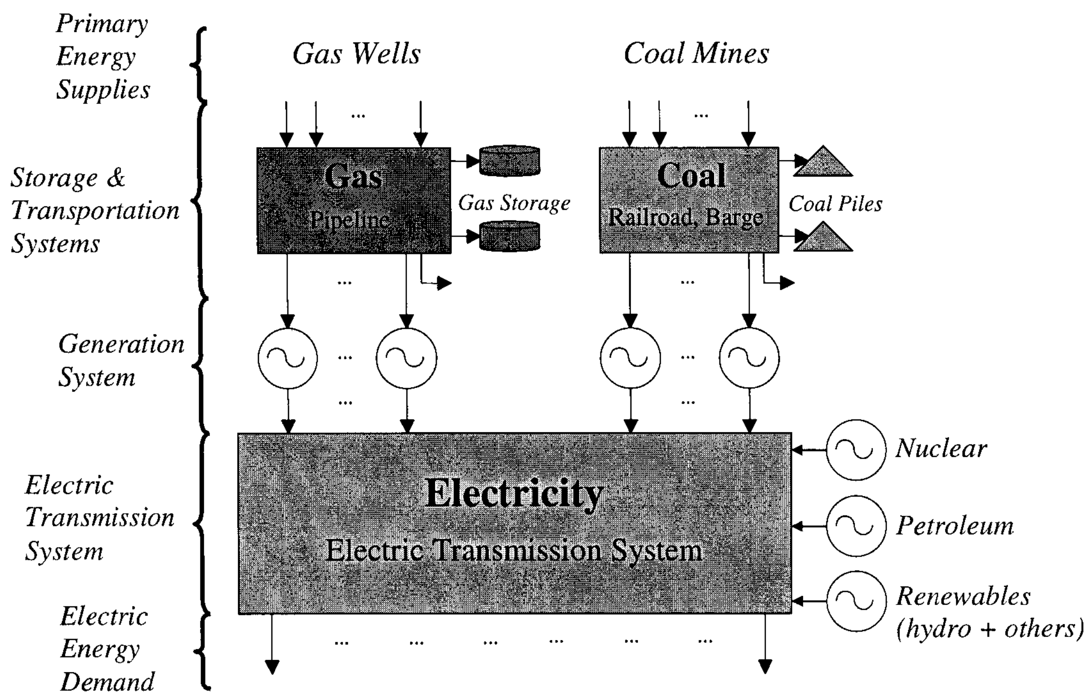

Figure 3.1 – The integrated energy system

Intra-subsystem couplings exist between four basic functionalities: supply, transportation, storage (where applicable), and demand. For example, the demand of natural gas influences its supply, storage, and transport. Obvious intra-subsystem couplings are also apparent for the electric and the coal subsystems.

Inter-subsystem couplings correspond to dependencies that transcend individual energy sectors, i.e., those that arise between the electric, coal, and gas subsystems. The subsystems interaction occurs mainly through the electric subsystem. For example, the supply of electricity largely determines the demand for coal and gas, as the material output from the coal and gas infrastructures are used by the electric energy subsystem (physical interdependencies). Likewise, limitations to coal or gas demand have a direct bearing on electricity supply. Geographic interdependencies may occur when different infrastructures are co-located in a common corridor. For instance, a situation where a major railroad used for coal transportation shares a portion of its path with a power transmission line translates a geographical coupling between the coal subsystem and the electric subsystem. Interdependencies also emerge as a result of compliances with environmental regulations. In particular, to achieve a predetermined level of SO_2 emissions, electric power plants are faced with a tradable permit system, which gives them enough flexibility to choose fuel switching as the strategy to attain the legislation requirements. Another category of interdependency is related with the fact that the different energy subsystems are linked through financial markets. Furthermore, one unique inter-subsystem coupling occurs between gas and electricity demand, as many customers have the capability to use either gas or electric heat (indirect competition).

The physical infrastructures, the environmental regulatory framework, and the markets that comprise the integrated energy system are undergoing rapid evolution, and the energy system is becoming more physically and economically interdependent. As the national infrastructures become more competitive, the different agents (electric power generation companies, natural gas suppliers, transmission companies, railroad companies, etc.) involved in the operation and use of the commodities explicitly represented in the model of the integrated energy system are looking into different strategies that would allow them to shed costs and maximize efficiencies. The objectives of this research work call for modeling the energy flows of coal, gas, and electricity production and transportation systems in a single integrated mathematical framework, for assessing the interdependencies between the fuel networks and the electric power system and analyzing of the overall economic efficiency of the system.

3.2 ENVIRONMENTAL EXTERNALITIES

The environmental impacts of electricity generation can be classified into the following categories:

- **Emissions of airborne pollutants**: in particular, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) associated with acid deposition, carbon dioxide (CO_2) and other greenhouse gases that contribute to global climate changes, particulates, and heavy metals;
- **Water use and water quality**: thermal pollution, waste water discharges, adverse impacts on fish populations or aquatic ecosystems, hydroelectric projects;
- **Land use values**: power plant and other infrastructures siting and waste disposal.

Although all forms of electricity generation involve some adverse environmental effects, these effects vary widely with the form of the primary energy used, the power plant capacity, the technology, etc. Furthermore, even two power plants using exactly the same primary energy, having the same electric power generation, and using the same technology will pose different environmental concerns depending upon their individual locations (flora and fauna, weather, population density, and other social structures). Because of the considerable uncertainty about the environmental impacts and a set of controversial issues that have not yet been fully resolved, most of these external diseconomies[1] are very difficult to measure and to value monetarily. These factors, combined with high potential expenses involved in reducing environmental damages, impose huge obstacles in the design of efficient policy instruments related to all aspects of electricity generation, at the federal, state,

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[1] External diseconomies: External diseconomies (also known as negative externalities or simply externalities) refers to situations that are caused by market failures, occurring when private costs are below social costs, leading to economic inefficiency and misallocation of resources in production. Market forces are likely to generate too much of an activity at too little price where diseconomies prevail.

and even local levels. As a result, most of the environmental impacts remain unaccounted for in the cost of power generation, as they are excluded from the prevailing regulatory framework. For example, no emission standards or required reductions exist for the release of CO_2 into the atmosphere, which is considered to contribute to the global warming phenomenon. Nonetheless, the increasing awareness of the environmental problems caused by the electric energy sector leads to the intensification of measures to internalize the externalities associated with electric power generation. In particular, the provisions of the Clean Air Act Amendments (CAAA) clearly require electric generators to reduce their emissions of SO_2 by defining an annual level of emissions (standard or cap) and implementing a tradable permit system. This is by far the most significant and well defined area covered by the regulatory treatment of externalities concerning electricity generation from fossil fuels, at the national level.

When fossil fuels are burned in the production of electricity, a variety of gases and particulates are formed and, if not captured by some pollution control equipment, they are released into the atmosphere. Among the gases emitted is SO_2, called a precursor to acid deposition. Under the right conditions, SO_2 reacts with other chemicals in the atmosphere to form sulfuric acid, which is then released onto the earth in the form of acid rain or dry deposition. To respond to increasing concerns about environmental and health problems associated with the emissions of SO_2, Congress passed the CAAA in 1990. As part of the provisions of the CAAA, the Environmental Protection Agency (EPA) was required to establish an innovative cap-and-trade mechanism to control the emissions of SO_2. Within this market-oriented framework, affected electric generating units are allocated allowances that can be freely traded, endowing electric utilities with considerable flexibility in determining their compliance strategies.

According to economists, the beauty of marketable permit systems such as the SO_2 allowance trading program is their cost efficiency feature and consequent improvement in social welfare relative to a standard or other environmental policy tools [69], [70]. While the cap establishes the social optimal level of emissions (at least theoretically), the trading activity allows sources to achieve optimality through a cost efficient procedure, where sources that have high marginal abatement costs can purchase additional allowances from sources that have low marginal abatement costs [71]. Thus, efficiency gains arise as sources trade allowances towards equating marginal abatement costs and minimizing total abatement costs. Furthermore, a well designed cap-and-trade program can also provide incentives for technological innovation [72].

The U.S. SO_2 allowance trading program was established under Title IV of the 1990 CAAA, which authorized EPA to establish a cap-and-trade program to control the emissions of SO_2 from fossil-fueled power plants across the 48 contiguous states and the District of Columbia. The primary goal of the program is an annual 10 million tons reduction of SO_2 emissions from 1980 levels. The provisions of the CAAA are instituted in two phases. Phase I ran from 1995 through 1999 and affected 263 boiler units in 110 mostly coal-fired power plants located in the Eastern and Midwestern regions of the country. Phase II, which is more stringent than Phase I, began in 2000, involving virtually all steam units with a nameplate capacity of 25 MW or greater and an eventual cap of 8.95 million tons of SO_2 emissions.

An allowance authorizes an affected source to emit one ton of SO_2 during a given year (vintage) or any future year. At the end of the compliance period (one year), each unit must hold an amount of allowances at least equal to its annual emissions. Allowances are allocated, free of charge (grandfathered), based on historic fuel consumption and an emission standard of 1.2 pounds of SO_2 per million British thermal units (lbs/MMBtu). New units that have come on line since enactment of the legislation are allocated zero allowances, i.e., they must purchase allowances for compliance. The absence of an allowance endowment to new units is often criticized as a barrier to entry. However, empirical studies have shown that this feature has not discouraged new capacity, especially from gas-fired and combined cycle units [73].

In addition to the annual allocation, allowances can also be obtained through yearly auctions held by EPA and conducted by the Chicago Board of Trade. Every year, a small portion of allowances under the cap (nearly 3%) are set aside in EPA reserves and made available for purchase at this auction. There is considerable research in the literature that supports the idea that auctions are more efficient than allocations [74]. However, these auctions were simply designed to ensure that new units have a public source of allowance. Furthermore, initially the auctions were intended to send a price signal to the market and, beginning in 1994, private market prices have come almost exactly into line with the results of the EPA auctions [75]. As the program matured, the auction has become a small component of total SO_2 allowance market activity, where private trading arrangements have since been the primary mechanism through which allowances are traded [76].

The integrated energy model explicitly incorporates emissions restrictions imposed by the CAAA and provides the flexibility to examine the impacts on energy flows and nodal prices of different stringency levels of environmental regulations. The compliance strategies that can be implemented in an operational time frame (e.g., fuel switching and allowance trading) are represented, as discussed later in chapter 4. Planning decisions, such as retrofitting units with scrubbers or building new power plant with lower emission rates, are not considered. Because of their small impact on the allowance market, allowance auctions are also not taken into account.

3.3 PROBLEM ARTICULATION

The purpose of this study is to evaluate the economic efficiencies of the integrated energy system, comprising the fuel networks and the electric power system. The framework proposed for that purpose is driven by fixed electricity demands, which must be satisfied at the minimum overall operating costs (fuel and operations and maintenance expenses), subjected to meeting engineering and environmental constraints. Chapter 5 contains a detailed discussion of the cost and performance assumptions specific to the integrated energy system model. This section provides an overview of the essential methodological and structural features of the model that extend beyond the assumptions specified in the next chapter.

3.3.1 Analysis Time Frame

The structure and objectives of this study determine a medium-term operational time scale. Although the model proposed is suitable to be applied to shorter or longer periods within an operational time frame, the time horizon selected is one year, because it reflects the cyclic pattern followed by the energy flows that are mainly driven by externally imposed seasonal variations (weather conditions). For instance, during the winter the demand of gas for heating purposes increases, which decreases the availability and increases the prices of this energy source delivered to power plants. On the other hand, the electric energy demand is higher during the summer (due to air conditioning), which leads to a larger requirement of primary energy from the power plants and the consumption of the energy from the storage facilities. The study period considered is the year 2002, because it is the most recent year for which complete data are available to characterize all different energy systems.

3.3.2 Model Boundaries

The boundaries of a model can be defined based on a clear understanding of the taxonomy of the variables. In this context, variables can be classified as endogenous, exogenous, or excluded [77]. Endogenous variables are those that are explicitly represented in the model and the dynamics of the system results from the interaction among them. That is to say that endogenous variables are the decision variables of the problem. Exogenous variables are those whose behavior does not change with the dynamics of the model, i.e., there are no feedback loops from the endogenous variables to the exogenous variables. In other words, exogenous variables represent those events for which the causal theory is not modeled (events outside the boundaries of the model). Exogenous variables may also be interpreted as input data. Likewise, endogenous variables may also be called outputs of the optimization problem. Finally, the variables that fall into the category of excluded are those that the model ignores. Table 3.1 presents the classification of the variables into the three categories mentioned above.

3.3.3 Level of Aggregation

Due to the enormous dimension of the problem, it is necessary to aggregate the physical components of the integrated energy system to some degree. Aggregation represents a trade-off among various factors such as computational performance and data availability on the one hand and credibility and accuracy of the results on the other hand. However, accuracy improves to a point as more detail is included and then levels off. On the other

Table 3.1 – Variables classification

Endogenous	Exogenous	Excluded
- Production schedules for coal and natural gas - Natural gas storage levels, injections, and withdrawals - Energy flow patterns for coal, gas, and electricity - Natural gas trade with Canada - Electricity generation from coal and gas fired power plants	- Electric energy demand - Electricity generation from nuclear, petroleum, hydro, and other renewable energies - Capacity limits - Operating costs - Efficiency rates - SO_2 emissions limit - Initial and final storage levels - Fuel purchase contracts - Natural gas trade with Mexico - Electricity trade with Canada - Non-electric power natural gas consumption	- Coal international trade - Coal transportation losses - Electricity trade with Mexico - Externalities related with water use, water quality, and land use values - Environmental costs from the front end of the fuel cycle[1]

hand, as the model contains greater levels of detail, computational performance degrades, and data requirements become infeasible to satisfy with available data. Even if detailed and complete data were available, aggregation would be necessary to keep the size of the optimization problem and the computational times within acceptable limits.

The different functionalities of the various energy subsystems represented in the integrated energy model use the level of aggregation that is most appropriate for the corresponding energy market, given the topology of the system and data availability restrictions. Even with a limited disaggregation of the integrated energy subsystem, the data challenges are remarkable. Most of the data on the physical infrastructures that comprise the system are publicly available from federal data collection agencies, but compilation and integration of the data are a formidable task. Data that are more difficult to acquire, such as some of the operating cost information, are assumed based on typical values.

[1] Fuel cycle: Series of physical and chemical processes and activities required to generate electricity from a specific fuel or resource, including extraction (mining, drilling) and preparation (milling, beneficiation), transport and storage of resources and materials, procession and conversion, and disposal. To the extent that the activities pertaining to the front end of the fuel cycle are not directly under the control of entities that are in the business of power generation, it is appropriate to ignore the related environmental regulations.

3.3.4 Model Dynamics

Static models have no underlying temporal dimension. However, in the case of an integrated energy model, we have to account for the evolution of the system over time, as inventory is carried over from one time period to another.

Multiperiod network flow models may be viewed as a composition of multiple copies of a network, one at each point in time, with arcs that link these static snapshots describing temporal linkages in the system. With this construction, the size of the network is proportional to the number of periods.

If a unique time step is chosen to apply to the entire model, it must be small enough to capture the fastest dynamics of the integrated energy system, which are imposed by the electric energy subsystem. However, this results in unnecessary and counterproductive computations that take place for slower energy subsystems. Alternatively, one can take advantage of the fact that the integrated energy system is composed of different energy subsystems with distinct dynamics, define a different time step for each one, and thus eliminate the burden of redundant simulation details. As a result, different simulation time steps can be used for different energy subsystems. For example, since the coal subsystem has relatively slow dynamics it can be modeled using the largest time step. Given the faster dynamics of the natural gas subsystem, it can be modeled using a smaller time step. Finally, in the electric subsystem, the time step chosen may be the smallest and may be defined according to loading conditions, given by a segmented load duration curve used to represent the demand.

Figure 3.2 gives a high-level representation of a multiperiod operation of the integrated energy system, where Tc, Te, and Tg represent the last time step for the coal, the electric power, and the gas subsystems, respectively. In the coal subsystem, $1 < Tc$, in the gas subsystem, $1 < x < y < Tg$, and in the electricity subsystem $1 < a < b < c < d < e < f < Te$. The arcs connecting the different time steps exist only in the fuel subsystems and represent the stock of fuel that is carried over from one period to the next, via storage.

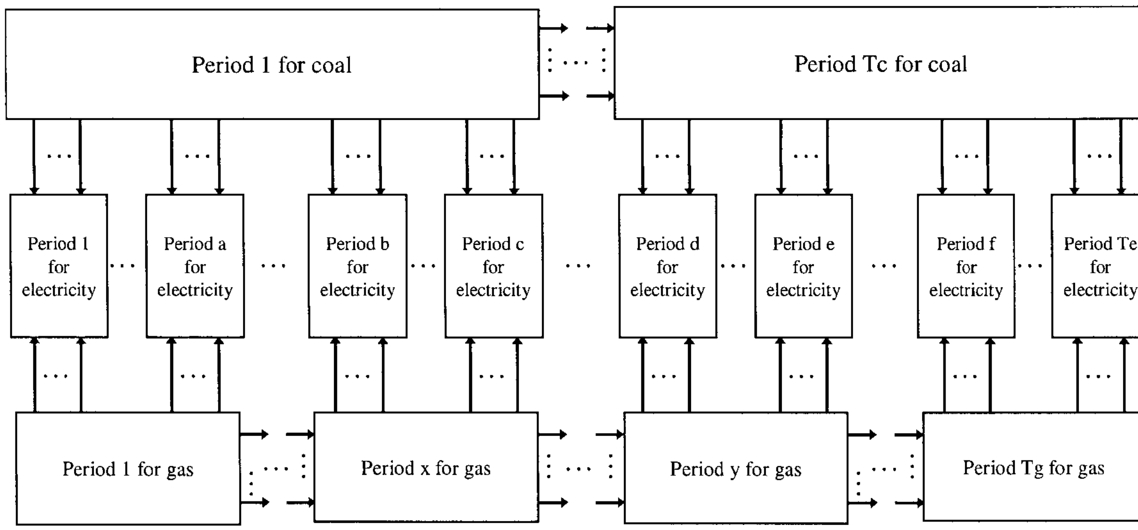

Figure 3.2 – High-level representation of a multiperiod operation

3.4 NETWORK FLOW MODEL

3.4.1 Introduction

Conceptually, the integrated energy model is a simplified representation of the coal, gas, and electricity systems, structured as a network composed of nodes and arcs, with energy flowing from node to node along paths in the network. Such a structure lends itself nicely to the adoption of the network flow programming modeling technique. The term network flow program describes a type of model that is a special case of the more general linear program. The class of network flow programs includes such problems as the transportation problem, the assignment problem, the shortest path problem, the maximum flow problem, the pure minimum cost flow problem, and the generalized minimum cost flow problem. Figure 3.3 shows the relationships between the various network flow programming models and linear programming. The models on the bottom are the least general. As we move to the top, the problems become more general. The core of the integrated energy system is a network flow model that falls into the category of generalized minimum cost flow problems. As it will be explained later in more detail, the constraint coefficient matrix of network flow problems (also called the node-arc incidence matrix) has a particular structure that distinguishes it from the broader linear programming category. Node-arc incidence matrixes are characterized by at most two non-zero elements in each column and in pure minimum cost flow problems these non-zero entries are either +1 or –1.

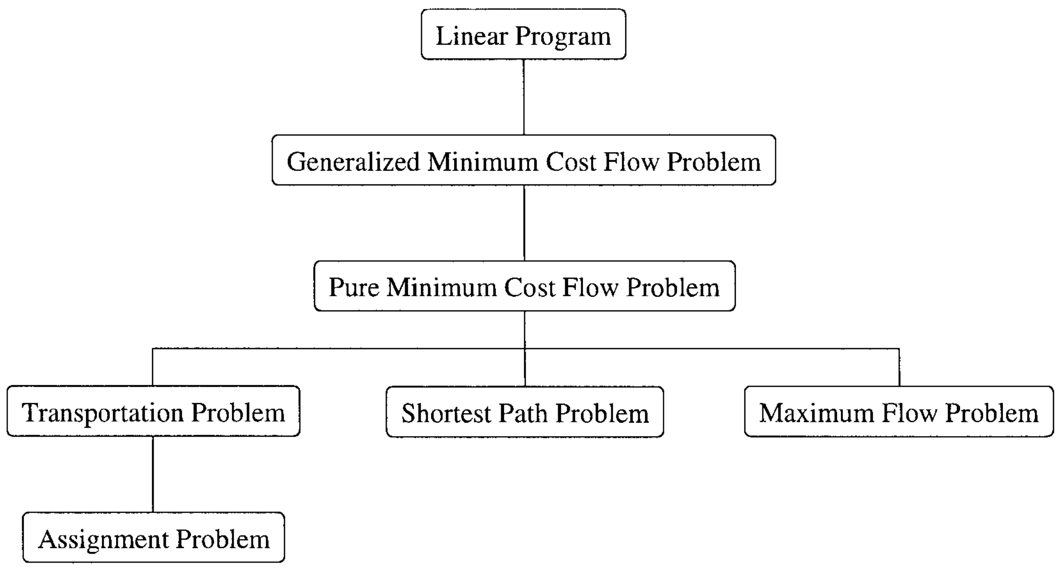

Figure 3.3 – The relationships between network problems

There are three properties that are responsible for the widespread use of network flow models in a vast range of application areas [78]: (i) visual content (these models allow for a problem to be depicted by means of diagrams and the pictorial appeal of these network diagrams make the problems easily understood by many users), (ii) model flexibility (network models can be used to identify the shortest path in a network, to solve a budget allocation problem, to probe the effect of government fiscal and regulatory policies, to analyze sociological phenomena, etc.), and (iii) solvability (there exist computationally very efficient algorithms, step-by-step solution procedures, for most network flow problems). When a situation can be entirely modeled as a network, very efficient algorithms exist for the solution of the optimization problem, many times more efficient than linear programming in the utilization of computer time and memory resources [79].

The scenario of the generalized minimum cost flow problem of the integrated energy system is the following. The supply node (source node) has an excess of coal or natural gas, while the demand nodes (sink nodes) require certain amounts of electric energy. The remaining nodes (transshipment nodes) neither require nor supply the commodity (energy), but serve as a point through which energy passes [80]. The energy flows through arcs that connect the nodes, and there is conservation of energy at the nodes, implying that the total flow entering a node must equal the total flow leaving the node. The arc flows are the decision variables for the network flow programming model. Associated with each arc are the following parameters:

- **Lower bound**, $e_{ij.min}$, (which can be zero) on the flow,
- **Upper bound**, $e_{ij.max}$, on the flow (also called capacity),
- **Cost**, c_{ij}, per unit of flow (which is the criterion for optimality),
- **Multiplier**, η_{ij}, (sometimes called efficiency or gain or loss factor) which multiplies the flow at the beginning of the arc to obtain the flow at the end of the arc.

The interpretation of the multiplier is the following: when 1 unit of flow is sent on arc (i, j), η_{ij} units of flow arrive at node j. It is a positive rational number that represents losses if $\eta_{ij} < 1$or gains if $\eta_{ij} > 1$. A network in which all arcs have unit gains is called a pure network. If some gains have values other than 1 the network is a generalized network. Multipliers substantially increase the flexibility of the network modeling approach beyond that of pure networks. Their ability to modify flows along the arcs makes it possible to represent increases or decreases in flow that actually occur in real world. In the integrated energy model, multipliers are used to represent, for instance, natural gas extraction losses, electric transmission losses along power lines, or any other type of efficiency measurement. Furthermore, the application of multipliers is particularly relevant to transform flows along arcs from one unit of measurement to another. Some examples include transformation of short tons of coal to million Btu (MMBtu) or thousand cubic feet (Mcf) of gas to MMBtu.

The goal of the network flow problem is to satisfy electric energy demands with available fossil fuel supplies at the minimal total cost, without violating the bound constraints, including emissions limit. The costs considered are the fossil fuel production, transportation, and storage costs, the operation and maintenance costs associated with electricity generating units operations, and the electric power transmission costs.

3.4.2 Node and Arc Definitions

The network flow model of the integrated energy system comprises the following nodes:

- **Source node**: The source node is an artificial node that supplies all the energy necessary to satisfy the electric energy demand. Supply can not be specified *a priori*, because it depends on the losses of the entire system, which in turn depend upon the flows.
- **Transshipment nodes**: The transshipment nodes represent the primary energy production facilities (coal mines and gas wells), the storage facilities (coal piles and natural gas reservoirs), and the energy conversion facilities (power plants).
- **Sink nodes**: The sink nodes represent the North American Electric Reliability Council (NERC) regions and subregions as defined by NERC, and each one is associated with a given demand.

Nodes may also represent an aggregation of different facilities with identical characteristics. For example, a coal supply node may represent an aggregation of several coal mines located in a particular region or zone, according to the level of granularity desired. Nonetheless, under the terminology that follows from the discipline of network flows and adopted in this paper, the price obtained as a by-product of the optimization procedure for this particular node is called the nodal price, although it can also be interpreted as a regional or zonal price.

The outgoing arcs of the dummy source node represent the production of coal and natural gas and imports of coal, gas, and electricity. In the coal and natural gas subsystems, arcs represent coal transportation routes and major gas pipeline corridors. Arcs also represent storage injections and withdrawals, and inventories carried over between two consecutive time periods. In the electric subsystem, arcs from the generators to their respective NERC region or subregion represent electricity generation, and arcs between regional nodes represent bulk electric power trade. Energy losses in the production, storage, and transportation of the primary energy forms, losses in the energy conversion process at the power plants, and losses in tie lines are represented by appropriately chosen multipliers on the arcs. Fuel production costs (extraction and processing charges) are associated with the outgoing arcs from the dummy source node; coal transportation rates and pipeline tariffs are assigned to the respective transportation arcs; storage fees are allocated to the arcs representing storage withdrawals; operation and maintenance costs of power plants are assigned to the arcs connecting the power plant nodes to the corresponding load nodes; and wheeling charges, or transmission costs associated with electric power trade, are allocated to the arcs representing tie lines.

Since the electricity demand is modeled at the level of the NERC regions and subregions, the only transmission lines represented in the model are the tie lines among NERC regions and subregions, whose flows can be considered decision variables since the control areas that operate them have the capability of controlling the imported/exported energy flow with their adjacent control areas. In contrast, the energy flows in the transmission lines within a control area can not be considered decision variables, because they are determined according to the Kirchhoff's laws.[1] As a result, only bulk power (wholesale) transactions are considered.

3.4.3 Tie Line Representation

A tie line is an undirected edge, because the energy can flow in both directions. Since the network flow model requires directed arcs, the transformation in Figure 3.4(b), shows an equivalent model where the undirected edge in Figure 3.4(a) is replaced by an oppositely directed pair of arcs. If the flow in either direction has a lower bound of value zero and the arc cost is nonnegative, in some optimal solution one of the flows in the directed arcs will be zero, which guarantees a non-overlapping solution.

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[1] Kirchhoff's laws: Kirchhoff's laws specify two fundamental rules for the transfer of energy through an electric circuit: (1) Kirchhoff's current law states that, at any node, the total electric current flowing into the node is the same as the total electric current leaving the node, and (2) Kirchhoff's voltage law states that the algebraic sum of the potential differences (voltages) around a closed path in a circuit must be zero.

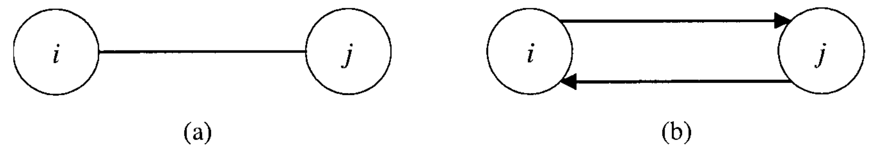

Figure 3.4 – Representation of tie lines

3.4.4 Elimination of Nonzero Lower Bounds

A network flow model with directed arcs with nonzero lower bounds can be replaced by an equivalent model with zero lower bounds. Figure 3.5(a) shows an arc with the parameters lower bound e_{min}, upper bound e_{max}, cost c, and multiplier η. An equivalent representation of the arc with zero lower bound is shown in Figure 3.5(b). Making this transformation requires an adjustment of the supply at both ends of the arc, i.e., b_i and b_j. This transformation also changes the objective function by a constant equal to $c \times e_{min}$ that can be recorded separately and then ignored when solving the problem.

Finally, it is interesting to note that when arcs have equal upper and lower bounds, i.e., when the flow is fixed, they can be eliminated from the equivalent network because its upper bound on the flow will be zero.

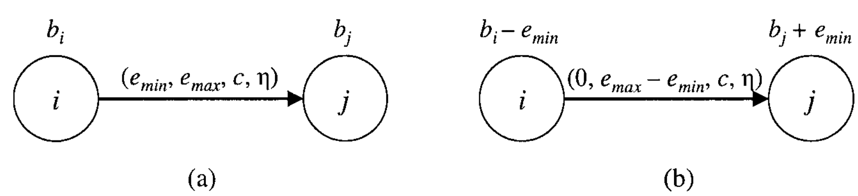

Figure 3.5 – Removing nonzero lower bounds

3.4.5 Restrictions on Nodes

In a standard network flow model, the only parameters associated with the nodes are the supply or demand specified at the source or sink nodes, respectively. In the integrated energy system, resources such as power plants and storage facilities have restrictions on the flow that can pass through them (e.g., capacities, efficiency rates, and costs), which are parameters associated with arcs in a network flow model.

The transformation into a standard network flow model is done by replacing each of these nodes by a pair of nodes with an arc connecting them. The parameters of this arc dictate the restrictions on the flow that passes through the respective facility. This transformation is illustrated from Figure 3.6(a) to Figure 3.6(b), where the parameters e_{min}, e_{max}, c, and η refer to the lower bound, upper bound, cost, and multiplier, respectively, of the facility originally represented by node i. This procedure is known as the node splitting technique.

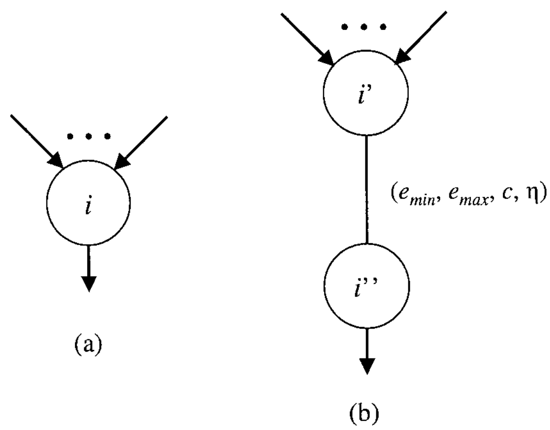

Figure 3.6 – Representation of restrictions on nodes

3.4.6 Linearization of Costs and Efficiencies

A typical input-output characteristic of a steam turbine generator can be represented by a convex curve [4]. When multiplied by the fuel cost, we obtain the generating unit cost as a convex function of the flow. Total cost functions can then be approximated by piecewise linear functions that lead to step incremental cost functions. In a network flow representation, each linearization segment is modeled by an arc, with the number of arcs determining the accuracy of the approximation. To illustrate this idea, we consider an arc that carries flow between nodes i and node j. The cost associated with the flow in this arc is a convex function and can be fitted by a piecewise linear cost function, as shown in Figure 3.7(a). This cost function tells us that the first 20 units of flow have a unit cost of \$2.5, the next 10 units of flow have a unit cost of \$5, and any additional amount has a unit cost of \$10, up to the capacity of 40 units of flow. In a network flow model, this situation is represented using a set of arcs, one for each segment of the piecewise linear cost function, as illustrated in Figure 3.7(b). Because the unit costs are increasing, the flow in a given arc will only be positive if all the other arcs with smaller unit costs have reached their capacity limits, which guarantees the feasibility of the solution. Since the piecewise linear function is an approximation of a continuous convex function, the number of arcs determine the accuracy of the approximation.

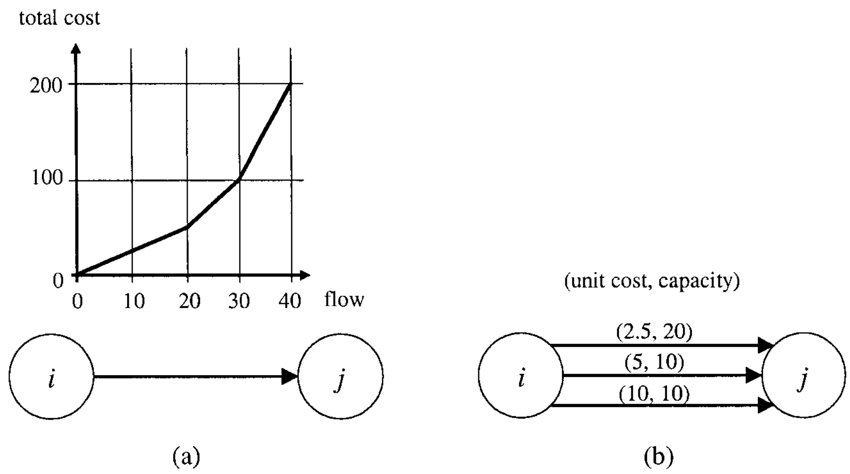

Figure 3.7 – Representation of convex cost function

Nonconvex cost functions, in particular those associated with the input-output characteristics of combined cycle[1] gas turbines, cannot be addressed with network flow programming techniques, and are therefore approximated by linear or piecewise linear convex functions. Although optimization techniques capable of dealing with nonconvexities are available [81], the cost in modeling complexity outweighs the improvement in model fidelity, considering the level of aggregation intended, which is mainly dictated by data availability restrictions.

Efficiency parameters may also be modeled using piecewise linear functions of the flow and can be represented by the multiple arc transformation illustrated above for convex cost functions. For example, power losses along the transmission lines are proportional to the square of the flow, and efficiency can therefore be approximated by a piecewise linear concave function where the slopes decrease with the flow. In this situation, it is guaranteed that the arcs with the higher efficiency parameters (lower losses) will be filled up first, since they require the smallest amount of flow, and thus the smallest cost, for the same energy demanded at the head node.

[1] Combined cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more combustion turbines (gas turbines). The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

CHAPTER 4. KEY COMPUTATIONS AND SOLUTION PROCEDURE

4.1 MATHEMATICAL FORMULATION

4.1.1 Generalized Network Flow Model

Mathematically, the multiperiod generalized minimum cost flow problem is an optimization model formulated as follows:

$$\text{Minimize } z = \sum_{t \in T} \sum_{(i,j) \in M} \sum_{l \in L_{ij}} c_{ij}(l,t) e_{ij}(l,t) \tag{1a}$$

subject to:

$$\sum_{\forall k} \sum_{l \in L_{jk}} e_{jk}(l,t) - \sum_{\forall i} \sum_{l \in L_{ij}} \eta_{ij}(l) e_{ij}(l,t) = b_j(t) \qquad \forall j \in N, \forall t \in T, \tag{1b}$$

$$e_{ij}(t) \leq e_{ij.\max} \qquad \forall (i,j) \in M, \forall t \in T, \tag{1c}$$

$$e_{ij}(t) \geq e_{ij.\min} \qquad \forall (i,j) \in M, \forall t \in T. \tag{1d}$$

where z is the objective function. The other symbols are described below.

Decision Variables:

$e_{ij}(l, t)$ Energy flowing from node i to node j, corresponding to the lth linearization segment, during time t.

Right-Hand Side Values:

$b_j(t)$ Supply (if positive) or negative of the demand (if negative) at node j, during time t.

$e_{ij.\max}$ Upper bound on the energy flowing from node i to node j.

$e_{ij.\min}$ Lower bound on the energy flowing from node i to node j.

Coefficients:

$c_{ij}(l,t)$ Per unit cost of the energy flowing from node i to node j, corresponding to the lth linearization segment, during time t.

$\eta_{ij}(l)$ Efficiency parameter associated with the arc connecting node i to node j, in the lth linearization segment.

Sets:

L_{ij} Set of linearization segments on the energy flowing from node i to node j.

M Set of arcs.

N Set of nodes.

T Set of time periods.

Indices:

i, j, k Nodes.

The objective function in (1a) represents the total costs associated with the energy flows from the fossil fuel production sites to the electricity end users. These total costs are defined as the sum of the fuel production costs, fuel transportation costs, fuel storage costs, electricity generation costs (operation and maintenance costs), and electricity transmission costs.

The set of constraints in (1b) represent the conservation of flow constraints (energy balance constraints) for all nodes and for all times. For a particular node, the first term of this constraint is the total outflow of the node (flow emanating from the node) and the second term is the total inflow of the node (flow entering the node). The conservation of flow constraint states that the outflow minus the inflow must equal the supply/demand of the node. The set of constraints defined by (1c) and (1d) are the flow bound constraints, which state that the flow must satisfy the capacity (1c) and lower bound (1d) of the respective arcs. The flow bounds represent the flows' operating ranges.

In matrix form, the problem can be represented as follows:

$$\text{Minimize } z = \underline{c}'\underline{e} \tag{2a}$$

subject to:

$$A\underline{e} = \underline{b}, \tag{2b}$$

$$\underline{e} \leq \underline{e}_{\max}, \tag{2c}$$

$$\underline{e} \geq \underline{e}_{\min}. \tag{2d}$$

In this formulation, A is an $n \times m$ matrix, where n is the number of nodes and m is the number of arcs. A is called the node-arc incidence matrix of the generalized minimum cost flow problem. Each column of A is associated with a decision variable, and each row is associated with a node. The column A_{ij} has a $+1$ in the ith row, a -1 or a $-\eta_{ij}$ in the jth row, and the rest of its entries are zero. An illustrative example of the formulation of the node-arc incidence matrix for a simple integrated energy system is presented in [67].

4.1.2 Side Constraint

As mentioned before, the overall objective of this optimization problem is to determine the energy flows that meet the demand for electricity at the minimum operating costs, subject to physical and environmental constraints. The mathematical formulation presented above is suitable to address the physical constraints of the integrated energy system. However, it is not sufficient to guarantee that the SO_2 emissions limit imposed by the CAAA is not exceeded. In addition to the energy balance constraints at all nodes and the flow bound constraints for all arcs, another constraint must be incorporated to impose a national-level limit on emissions. According to the CAAA, the allowances for SO_2 emissions are traded nationwide so the corresponding limit on emissions is actually national rather than regional or unit-level. This national limit is determined by the sum of the allowances allocated to power plants (as defined by the CAAA) and adjusted to capture the exogenously given emissions banking effects. The amount of emissions produced depends on the fuel used, the pollution control devices installed, and the amount of electricity produced. The additional constraint may be represented as follows:

$$\sum_{t \in T} \sum_{(i,j) \in G} SO2_i(t) \cdot (1-\alpha_i) \cdot \sum_{l \in L_{ij}} e_{ij}(l,t) \leq NSO2 \tag{1e}$$

Decision Variables:

$e_{ij}(l, t)$ Energy flowing from node i to node j, corresponding to the lth linearization segment, during time t.

Right-Hand Side Value:

$NSO2$ National SO_2 limit.

Coefficients:

$SO2_i(t)$ Emissions rate associated with the fuel consumed by power plant i, during time t.

α_i Removal efficiency of to the pollution control equipment installed at power plant i. If no pollution equipment exists at power plant i, then $\alpha_i = 0$.

Sets:

G Set of arcs that represent electricity generation. (This is a subset of M.)

L_{ij} Set of linearization segments on the energy flowing from node i to node j.

T Set of time periods.

Indices:

i Nodes that represent power plants.

j Nodes that represent load centers.

All compliance strategies that can be implemented in an operational time frame – fuel switching (e.g., use low sulfur content coal or natural gas instead of high sulfur content coal), utilization of emissions control devices or abatement technologies (e.g., scrubbers, particulate collectors), revising the dispatch order to utilize capacity types with lower emission rates more intensively, and allowance trading – are now effectively captured by the mathematical model described by equations (1a)-(1e).

The inequality constraint (1e) can be transformed into an equality constraint and incorporated in the matrix equation (2b). The transformation from inequality to equality form is done by introducing a nonnegative slack variable in the left-hand side of the equation. With the addition of constraint (1e) to equation (2b), some of the columns of the matrix $\boldsymbol{A}$ have now more than two non-zero entries, which makes it no longer a node-arc incidence matrix, but instead a more general constraint coefficient matrix. In linear programming terminology, the constraint (1e) is called a bundle, complicating, or side constraint, which specifies a flow relationship between several of the arcs in the network flow model. The integrated energy system can also be interpreted as a multicommodity flow problem, where energy and emissions are the commodities that flow along the arcs of the network. The complicating constraint ties together these two commodities.

4.2 NODAL PRICES

The Karush-Kuhn-Tucker conditions associated with the constrained linear optimization problem defined above yield the so called Lagrangian multipliers or dual variables [82]. In economic terms, the Lagrangian multipliers are explained as the shadow values related with each active constraint at the optimal solution of the choice variables, and they represent the marginal costs of enforcing the constraints. In a network flow formulation, these shadow prices are also referred to as nodal prices, because each node of the network structure has a Lagrangian multiplier associated to it, as a result of the mass balance constraints defined for the nodes.

For simplicity, and without loss of generality, let us assume that the cost and efficiency parameters associated with each arc are constant functions. This permits the elimination of the parameter l, for notational simplicity. The Lagrangian function for (1a)-(1e) is then:

$$\begin{aligned} \mathrm{L} = & \sum_{t\in T}\sum_{(i,j)\in M} c_{ij}(t)e_{ij}(t) + \sum_{t\in T}\sum_{j\in N}\lambda_j(t)\left[\sum_{\forall k} e_{jk}(t) - \sum_{\forall i}\eta_{ij}e_{ij}(t) - b_j(t)\right] + \\ & + \sum_{t\in T}\sum_{(i,j)\in M}\delta_{ij}(t)\left[e_{ij.\min} - e_{ij}(t)\right] + \sum_{t\in T}\sum_{(i,j)\in M}\mu_{ij}(t)\left[e_{ij}(t) - e_{ij.\max}\right] + \\ & + \gamma\left[\sum_{t\in T}\sum_{(i,j)\in G} SO2_i(t)\cdot(1-\alpha_i)\cdot e_{ij}(t) - NSO2\right] \end{aligned} \tag{3}$$

where $\lambda_j(t)$ is the Lagrangian multiplier associated with the energy balance constraint at node j for time t. In other words, $\lambda_j(t)$ is the nodal price for node j, during time t. $\delta_{ij}(t)$ and $\mu_{ij}(t)$ are the Lagrangian multipliers associated with the lower and upper bound constraints, respectively, on the energy flowing from node i to node j, during time t. Finally, γ is the Lagrangian multiplier associated with the emissions limit constraint.

For optimality, in a given time period t, the relationship between the nodal prices of two linked nodes i and j, is given by one of the following equations. If $(i,j)\notin G$, that is (i,j) does not represent electricity generation, then:

$$\frac{\partial \mathrm{L}}{\partial e_{ij}(t)} = c_{ij}(t) + \lambda_i(t) - \lambda_j(t)\eta_{ij} - \delta_{ij}(t) + \mu_{ij}(t) = 0 \tag{4a}$$

Otherwise, if $(i, j) \in G$, that is (i, j) is an arc representing electricity generation, then:

$$\frac{\partial L}{\partial e_{ij}(t)} = c_{ij}(t) + \lambda_i(t) - \lambda_j(t)\eta_{ij} - \delta_{ij}(t) + \mu_{ij}(t) + \gamma SO2_i(t)(1-\alpha_i) = 0 \tag{4b}$$

If the inequality constraints are slack, i.e., not binding or not active, the corresponding Lagrangian multipliers are zero. Therefore, from equation (4a) we conclude that if the flow bound constraints are not binding, the cost is zero ($c_{ij}(t) = 0$), and there are no losses ($\eta_{ij} = 1$), then the nodal prices of two linked nodes are the same ($\lambda_i(t) = \lambda_j(t)$). Likewise, from equation (4b) we conclude that the nodal price at a power plant node i is the same as the nodal price at the corresponding electricity demand node j if and only if the flow bound constraints are not binding, the arc cost is zero, there are no transmission losses, and the emissions limit constraint is also not binding. If the environmental constraint is binding, the nodal price at the demand node j is given by:

$$\lambda_j(t) = \lambda_i(t) + \gamma SO2_i(t)(1-\alpha_i) \tag{5}$$

The component $\gamma SO2_i(t)(1-\alpha_i)$ is a positive value that represents the marginal cost of enforcing the emissions limit constraint at the power plant node i. It adds to the nodal price of the power plant, λ_i, to yield the nodal price at the demand node, λ_j. It is interesting to note that the marginal cost of enforcing the environmental constraint in a given power plant i depends on the national cap set for emissions (which contributes to the definition of the Lagrangian multiplier γ), the sulfur content of the fuel used (which determines the rate $SO2_i$), and the removal efficiency of the flue gas desulfurization[1] (FGD) equipment, if any (which defines α_i).

In the context of the electric power industry, the concept of nodal prices has become more and more familiar, as several electricity markets have used the information from nodal

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[1] Flue gas desulfurization: Flue gas desulfurization (scrubber) is a post combustion control technology designed to remove SO_2 from the emission stack. In a scrubber, the gases resulting from combustion are passed through tanks containing a sorbent that captures and neutralizes the SO_2.

prices to improve the efficient usage of the power grid, to perform congestion management, and also to design a pricing structure for the power system [83]. In the power industry terminology, nodal prices are often referred to as locational marginal prices, or LMP. In 2002, the Federal Energy Regulatory Commission (FERC) proposed a standard market design that incorporates a locational marginal pricing mechanism to induce efficient electric power markets [84]. In contrast with a single price mechanism, under a nodal pricing scheme market clearing prices are calculated for a number of locations on the transmission grids called nodes. Prices vary from node to node because of transmission line congestion and losses [85]. At each node, the price represents the locational value of electric energy, including the cost of energy and the cost of delivering it, i.e., losses and congestion. In other words, the nodal price is the cost of serving the next megawatt of load at a given location. Therefore, LMP can be used to determine the value of transmission rights and to provide economic signals for generation and transmission investments [86]. Many aspects pertaining to the usage of LMPs in the electric power sector have been investigated and are available in the literature [87], [88], [89], [90], [91], [92].

As mentioned before, LMP is the basis for transmission congestion management and is currently used as the pricing mechanism for wholesale power in many Regional Transmission Organizations (RTO) and Independent System Operators (ISO) including the Pennsylvania – New Jersey – Maryland Interconnection (PJM) [93] and New York ISO. Given its successful history, the energy market design in PJM is widely recognized as setting an example for other electricity markets.

The concept of nodal prices widely used in the electric power arena is herein expanded to the integrated energy system, by optimizing the energy flows in a generalized network flow model that explicitly represents the electric subsystem together with the various fossil fuel networks in a single mathematical framework. Since all entities involved in the operation of the energy system are fully represented, the nodal prices obtained as a by-product of the optimization procedure provide a means to identify the interdependencies between the fuel subsystems and the electric subsystem [94]. Knowledge and understanding of these interdependencies is expected to induce the most economically efficient use of fuel production, fuel storage, fuel transportation, electricity generation, demand, and transmission resources, through the correct economic signals provided. In addition, because nodal prices monetize congestion costs, they provide clear economic signals that indicate where infrastructure improvements should take place to relieve constraints, thus promoting efficient investment decisions.

4.3 SOLUTION PROCEDURE

4.3.1 Generalized Network Simplex Algorithm

Most problems involving linear objective functions and linear constraints can be articulated as linear programs, and therefore solved by the *simplex algorithm.* Furthermore, if the constraints can be formulated such that every column of the constraint coefficient matrix has at most two non-zero entries (which is the case for network flow problems), then the problem is said to have a network structure and, the constraint coefficient matrix is called the node-arc incidence matrix. Like for all problems in mathematical programming, an algorithm that is specifically designed to solve that particular class of problems is more efficient on that class than a general purpose algorithm. The minimum cost flow problem can be formulated as a linear program and solved using the simplex method, but it is more efficient to use the *network simplex algorithm* for this problem. These special purpose algorithms achieve extraordinary efficiencies by exploiting the special structure inherent in the network flow problems (computational efficiency can be further improved by two orders of magnitude [95]). Since the arcs of the integrated energy system model do not conserve flow, the node-arc incidence matrix has entries that are different than -1, 0, and $+1$. This formulation is said to have a generalized network flow structure, and the fastest available algorithm to solve this kind of optimization problems is called the *generalized network simplex algorithm*, which is an adaptation of the network simplex method used to solve pure minimum cost flow problems.

Although the worst case complexity for the generalized network simplex algorithm is exponential, in practice the running time of this algorithm is a lower order polynomial in n and m [96], where n is the number of nodes and m is the number of arcs. A careful implementation of the generalized network simplex algorithm provides the optimal solution in less than $O(nm)$ time. Since, in general, $m >> n$, it is the number of arcs which (essentially) determines the solution time. Empirical investigations have further determined that the generalized simplex algorithm is only two to three times slower than the network simplex algorithm for the minimum cost flow problem.

Commercial computer codes for the minimum cost network flow problem are readily available and able to solve large problems. The CPLEX software solver from ILOG, for example, has a first-rate implementation of the network simplex algorithm [97].

4.3.2 Decomposition Techniques

As explained in section 4.1.2, environmental restrictions are considered by adding a side constraint to the generalized network flow problem, which makes the generalized simplex algorithm invalid for direct application to solve this optimization problem. Furthermore, note that the problem is largely separable by time period, with a large number of arcs connecting various nodes within a single time period, but relatively few arcs connecting different periods (only those associated with storage facilities). This implies that most of the constraint coefficient matrix has a block-angular structure with complicating or bundle constraints that couple the solutions for different periods. This type of structure lends itself nicely to the application of solution strategies known as decomposition techniques, particularly the *price-directive* schemes such as the Lagrangian relaxation method [98] and Dantzig-Wolfe decomposition [99]. Price-directive approaches are so called because they eliminate or relax the complicating constraints by applying Lagrangian multipliers to them and bringing them into the objective function. Decomposition has proven particularly effective for multicommodity flow problems.

The characteristics of the integrated energy system allow modularity and decomposition at different levels. In order to perform a variety of analyses, it may be advantageous to disaggregate the problem by energy type, by time frame, or by geographical area. For that purpose, Benders' decomposition [100] (a *resource-directive* approach) can be very useful since it allows the decomposition of the problem by variables rather than constraints. For example, if the desire is to refine the model of electricity generation, the variables associated with electricity generation would be the complicating variables. In this scheme, the master problem would minimize total cost over these variables, while subproblems would optimally supply the resources needed to generate electricity, as specified by the complicating variables. An analogous strategy could be developed to refine other parts of the model, albeit with different choices of complicating variables.

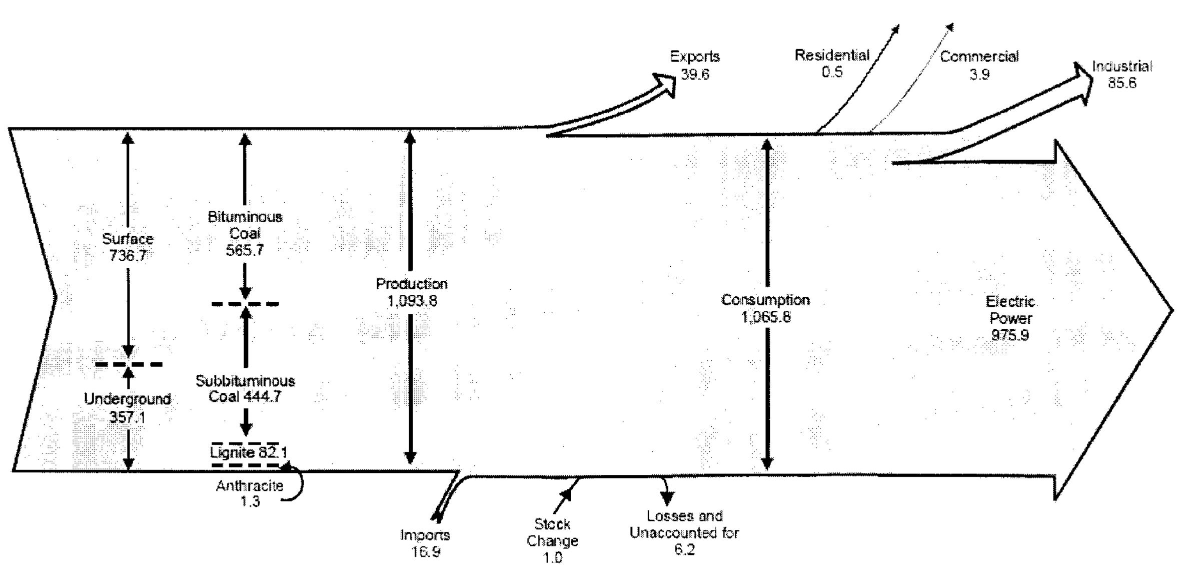
The implementation of decomposition techniques contributes to significantly decrease the computational time. Although the solution obtained by these methods is not necessarily optimal, it may be appropriate to sacrifice optimality and gain in computational cost, given the dimensionality of the problem. Other excellent references on network modeling and solution algorithms include [101], [102], [103], [104], [105].

The network optimizer algorithm implemented by the CPLEX solver is suitable to solve network flow problems with side constraints. CPLEX automatically recognizes the embedded network structure, solves this portion using the network simplex algorithm, and then performs standard linear programming iterations (either the primal simplex method or the dual simplex method) on the full problem using the network solution to construct an advanced starting point. This advanced basis defines an attractive starting solution for the simplex method, because it takes advantage of the underlying network structure and flow costs to generate an efficient starting solution for the algorithm. For problems with few complicating constraints (such is the case of the integrated energy system), the advanced basis can be a very good approximation of the optimal solution of the problem and so can greatly improve the performance of the simplex method.

CHAPTER 5. MODELING ASSUMPTIONS

5.1 COAL SUBSYSTEM

This section is a detailed description of the modeling assumptions for the coal subsystem. The nodes, arcs, and associated parameters (costs, efficiencies, and capacities) are defined. All data sources used to characterize the coal supply nodes and coal transportation arcs are identified and the methodology adopted to resolve data gaps is presented. Figure 5.1 gives an overview of the coal industry in 2002.



Source: Energy Information Administration

Figure 5.1 – Coal flow diagram, 2002 (million short tons)

5.1.1 Coal Production

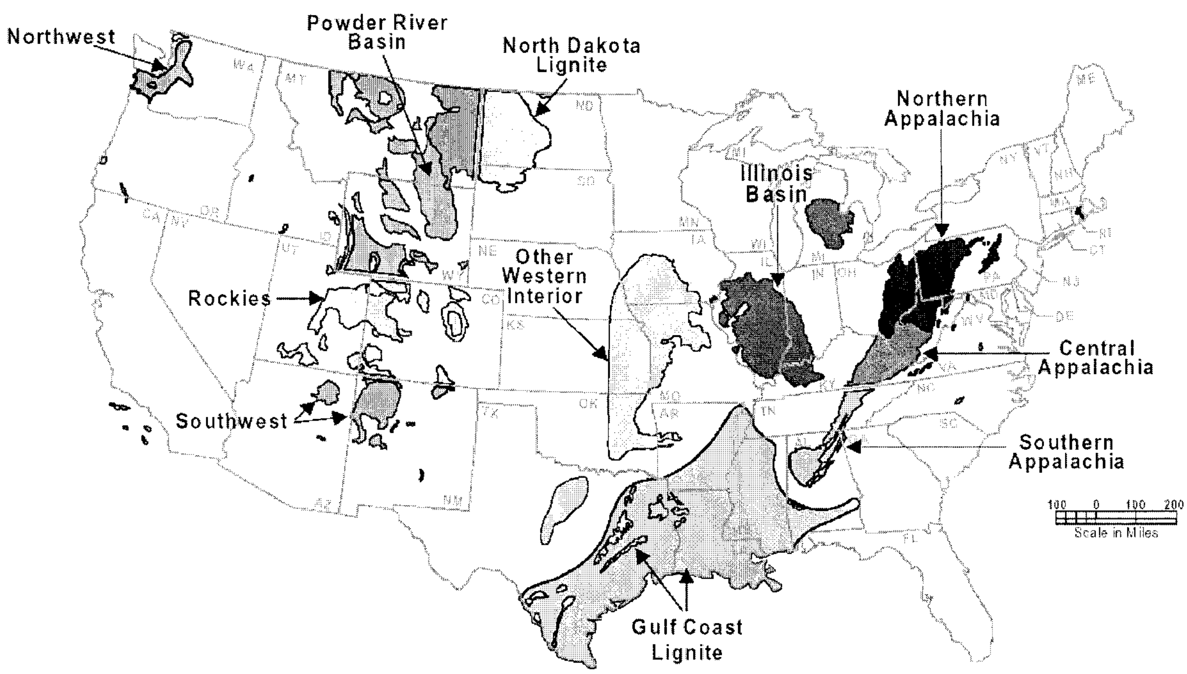
Coal is mainly found in three large regions: Western, Interior, and Appalachian. Coal production occurs in many locations across 26 states. In 2002, the Western region was responsible for 50% of the national coal production, the Interior region produced 15%, and the Appalachian region accounted for the remaining 35%. The Powder River Basin of Wyoming, which is allocated to the Western coal region, is the nation's leading source of coal, accounting for almost 36% of the total coal production [106].

Coal is a fossil fuel that is formed from plant remains that have been decomposed over geologic time. Different amounts of heat and pressure during the geochemical stage of coal development give origin to different types of coal: lignite, subbituminous, bituminous, and anthracite. The heating value, carbon content, sulfur content, and hardness increase progressively from low rank coal (lignite) to high rank coal (anthracite). Most of the coal used in the generation of electricity is either bituminous or subbituminous. Lignite is typically used only when higher grades of coal are not available or affordable. Concern over environmental quality has led to lesser use of the hardest coal, anthracite.

Coal deposits in the Western region are mostly subbituminous, while bituminous coal comes mostly from the Appalachian basin and the Midwest. The youngest coal, lignite, is only used in North Dakota and Texas. Although most of the supplies of anthracite have been exhausted, it can still be found in Pennsylvania.

There are basically two methods for extracting coal: underground (deep) mining methods and surface (open cast) mining methods [107]. The choice of the appropriate coal mining technology depends on the geological conditions of each location, which determine the physical and chemical attributes of coal deposits. Appalachian coalfields are characterized by relative thin seams, high heating value, high sulfur content, and deep burial of the bulk of the coal seams. As a result, the majority of the coal from the Appalachian region is extracted using underground mining techniques. The Western coalfields, on the other hand, are geologically younger and many of the coal deposits occur close to the surface. Western coalfields are characterized by relative thick seams, low heating value, low sulfur content, and shallow burial of large reserves. In consequence, most of the coal from the Western region is extracted through surface mining. The Interior coal region is somehow a mix of the Appalachian and the Western regions. In general, surface mining is characterized by higher labor productivity and lower operating costs than underground mining, which translates into lower minemouth prices.

To account for such geological (physical and chemical), geographical, and technological heterogeneities, every coal mine is assigned to one of the eleven coal supply regions shown in Figure 5.2.



Source: Energy Information Administration

Figure 5.2 – Coal supply regions

For each coal supply region a coal supply node is defined, which means that eleven coal supply nodes are represented in the model. Table 5.1 lists these nodes and associated productive capacity, average heat value, average sulfur content, and average minemouth price.

Table 5.1 – Coal supply nodes

Supply node	**Productive capacity (thousand short tons)**	**Avg. heat value (MMBtu/ton)**	**Avg. sulfur content (lbs. sulfur/MMBtu)**	**Avg. minemouth price (2002 $/short ton)**
Northern Appalachia	169,819	24.04	1.83	24.79
Central Appalachia	335,926	25.03	0.75	30.18
Southern Appalachia	28,221	24.66	0.57	33.61
Illinois Basin	121,801	22.73	2.03	22.86
Western Interior	2,538	23.58	2.28	27.86
Gulf Coast Lignite	56,063	13.10	1.62	17.02
North Dakota Lignite	32,400	13.24	1.15	8.46
Powder River Basin	479,761	17.45	0.39	6.63
Rocky Mountains	75,185	22.81	0.40	17.96
Southwest	56,653	20.22	0.63	22.47
Northwest	7,284	15.63	1.13	8.92

Productive capacity denotes the maximum amount of coal that can be produced annually, as reported by mining companies on EIA Form 7A. Due to the proprietary nature of the data collected through this survey form, it is not publicly available. However, it is the primary source of information for EIA publications such as the "Annual Coal Report" [108], "Annual Energy Outlook" [109], "Annual Energy Review" [110], and the "State Coal Profiles" [111]. On these publications, data are available as detailed as at the state level, and for some states information is further disaggregated by regions. In cases where only one company operates in a particular area, information is withheld to avoid disclosure of individual company data. In these situations the productive capacity is estimated by dividing the actual annual production as reported by the U.S. Department of Labor, Mine Safety and Health Administration (MSHA), Form 7000-2, by the national average 2002 capacity utilization of coal mines, which was 80.03% [108, Table 12].

The average heat and sulfur content values are estimated from data obtained from the FERC Form 423 databases. The heat value is an indication of the energy content of the coal. More specifically, it denotes the heat produced by the combustion of the coal, measured in million Btu per short ton. Sulfur content designates the amount of sulfur that is released during combustion and is expressed in pounds of sulfur per million Btu.

The minemouth price is the free on board (f.o.b.) mine price. It is the price actually charged at the producing site for the coal sold on the open market. It includes mining and coal preparation costs and excludes freight transportation costs and insurance charges. This information is gathered through EIA Form 7A and obtained from the EIA publications mentioned above. Those states for which data is not available to avoid disclosure of individual company data are excluded from the average calculation of the corresponding coal supply node.

In summary, Table 5.1 is completed based on data collected through the following survey forms:

- EIA Form 7A, "Coal Production Report," collects data on coal production operations, locations, productive capacities, coal beds mined, reserves, and disposition, on an annual basis. All U.S. coal mining companies that owned a mining operation which produced and/or processed 10,000 or more short tons of coal are required to report.

- U.S. Department of Labor, Mine Safety and Health Administration (MSHA), Form 7000-2, "Quarterly Mine Employment and Coal Production Report." Through this form, the MSHA collects employment and production information from mine operators for each quarter of operation at the mine.
- FERC Form 423, "Cost and Quality of Fuels for Electric Plants," is a report on fuel delivered cost, quantity, and quality (ash, Btu, and sulfur content). All electric generating plants with capacity of 50 MW or more are required to submit these data on a monthly basis.

5.1.2 International Coal Trade

The United States has historically been a net coal supplier in the international marketplace. In 2002, coal exports reached 39.6 million short tons and coal imports were 16.9 million short tons (see Figure 5.1). Coal exports represent 3.6% of U.S. coal production and more than half of the coal exported is metallurgical coal. Canada is the principal market for U.S. coal exports, both steam and metallurgical coal, followed by Brazil and western European countries. Coal imports comprise only 1.6% of domestic consumption. Imported coal is mostly steam coal. Colombia dominates the U.S. coal import market, followed by Venezuela and Canada [112].

Because coal exports and imports represent a small percentage of the U.S. coal production and consumption, respectively, and since steam coal exports are approximately counterbalanced by steam coal imports, international coal trade is neglected.

5.1.3 Coal Transportation

Although coal is used by every state in more than 400 electric power plants, only 26 states actually mine it. As a result, coal is transported over long distances and in large quantities. The primary transportation routes for moving coal are railroads, rivers, and highways. In 2002, 70% of the coal transported for electricity generation was moved by trains, 11% by barges, and 9% by trucks [113]. Lake carriers, conveyor systems, and coal slurry pipeline represent other means of transporting coal.

As the dominant transportation mode for coal, railroads play a central role herein. Actually, a mutual dependency exists, because coal is the most important single commodity carried by rail. According to the Association of American Railroads (AAR), in 2002 coal accounted for 44% of total freight tonnage and 21% of total freight revenue for Class I railroads[1] [114]. The majority of the railroad coal shipments occur in the so-called unit trains. Unit trains consist of a dedicated set of equipment that specializes in the transport of only one commodity (e.g., coal) directly from origin to destination (in this case, from the mine to an electric power plant), with no stops in transit. A typical coal unit train involves the transportation of 10,000 tons of coal in 100 hopper or gondola cars, each with a 100 ton capacity. The average haul for coal transported by railroads is around 800 miles per ton. Coal originated from the Rocky Mountains and Powder River Basin supply regions lead the list of average coal transportation distance by rail, with 1,143 and 1,096 miles, respectively, followed distantly by the Western Interior and Central Appalachia supply regions, with 500 and 457 miles, respectively [115]. The average coal transport rate by rail is about $10 per ton or 12 mills per ton-mile.

Rivers rank next to railroads in coal shipment routes. The major inland waterways for coal traffic are the Mississippi, Ohio, and Black Warrior-Tombigbee rivers. In these rivers, a typical towboat pushes 15 to 20 barges loaded with 20,000 to 30,000 tons of coal [117]. The amount of coal shipped in a single tow is determined by the lock size on the water navigated. The average distance shipped by barges is about 300 miles per ton. The Appalachian regions and the Illinois Basin are the supply nodes from which coal is shipped by barges. Due to the fact that water carriers do not have to supply or maintain their right-of-way, water transportation is the least expensive way to ship coal. The average coal transport rate by barge is about $2 per ton or 12 mills per ton-mile.

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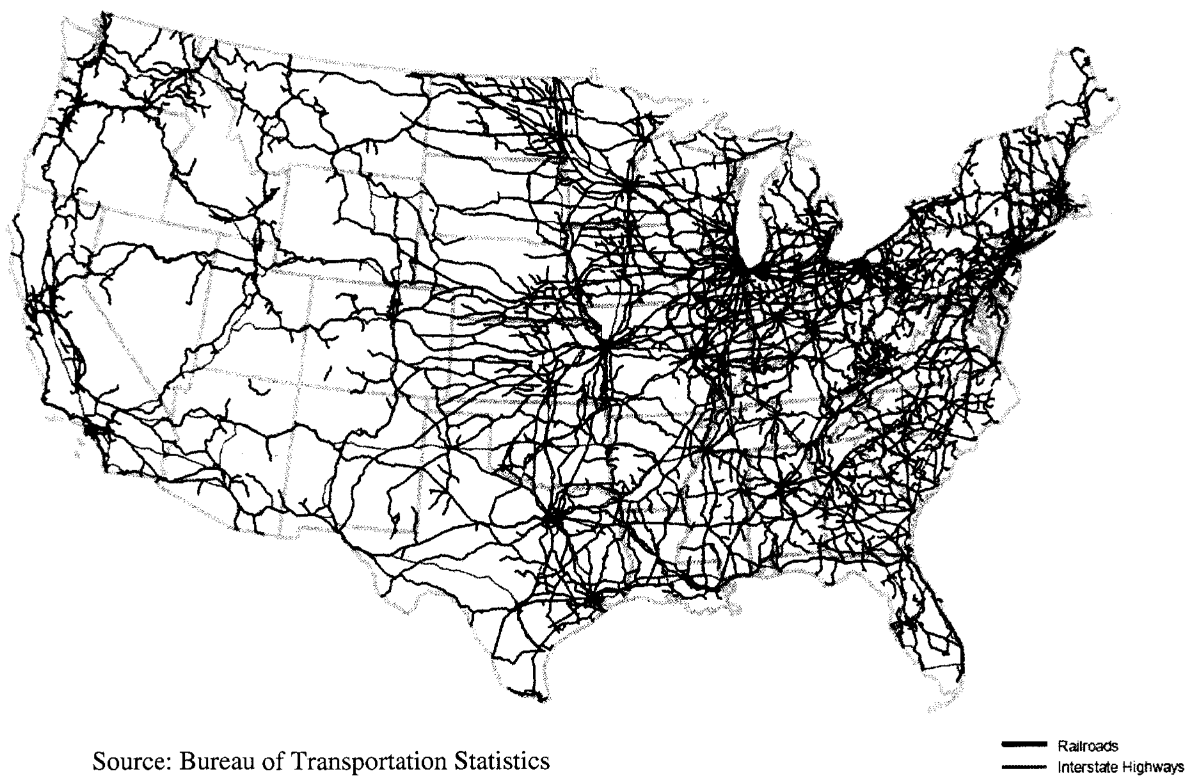
[1] Class I railroad: As defined by the Surface Transportation Board, Class I railroads are line haul freight railroads with 2002 operating revenue of at least $272 million. Class I railroads in 2002 are: The Burlington Northern and Santa Fe Railway, CSX Transportation, Grand Trunk Corporation, Kansas City Southern Railway, Norfolk Southern Combined Railroad Subsidiaries, Soo Line Railroad, and Union Pacific Railroad.

Coal deliveries by truck are used for short hauls, generally less than 50 miles. The significant advantage of trucks is the high degree of route flexibility. In some instances, truck is the only method by which coal can be transported. Frequently, trucks are also used to move coal to loading docks to be further transported by rail or barge. Individual coal shipments by truck are relatively small (20 to 35 tons) and the maximum load a truck can carry on highways is limited by state regulations [116]. The average coal transport rate by truck is about $6 per ton or 234 mills per ton-mile.

As mentioned before, lake carriers, conveyor systems, and coal slurry pipeline are the other transportation modes for coal. Shipping on the Great Lakes is conditioned by the weather conditions, and it is usually immobilized during the winter. Conveyors are often used to deliver coal directly from mines to nearby power plants, and can be many miles long. Regarding coal slurry pipeline, the only such system operating in the United States is the Black Mesa line, connecting a coal mine in northern Arizona to a power plant in southern Nevada, spanning 273 miles.

Figure 5.3 shows the railroad network and interstate highways, which serve as the major coal transportation routes. Precise modeling of the over thousands of individual transportation routes used to transport coal from mines to electric power plants would require an enormous detailed and very complex model, using large quantities of data that are not in the public domain. In addition, an adequate coal transportation model should recognize that coal transportation rates are often route specific. In some locations, due to the lack of competition and the price elasticity of demand, coal carriers have historically been able to exert substantial market power and extract economic rents. This means that it is not appropriate to define coal transportation rates based on the transportation mode and distances. As a result, a simplified approach is adopted, where an arc is established between each coal supply node and all feasible coal-fired power plants. A transportation link is considered not feasible, and therefore not included in the model, when it represents an either economically or physically impractical route. Transportation capacity is assumed to become available as needed to meet the transportation requirements. Transportation costs are inferred by subtracting the average minemouth price as defined in Table 5.1 from the average delivered prices. Delivered prices for each power plant are obtained from FERC Form 423.



Source: Bureau of Transportation Statistics

Figure 5.3 – Railroad network and interstate highways

To account for existing contractual agreements between the power plants and their coal suppliers, the lower bound of these transportation arcs is adjusted. Information regarding contractual commitments, including origin/destination, quantity, quality, delivered price, and expiration date, is available from the EIA's Coal Transportation Rate Database (CTRDB). The CTRBD is a comprehensive database that contains electric utility coal supply contract data and transportation related data. The data for this database is originated from the public use files of the FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," supplemented by data from the Surface Transportation Board (STB) annual "Carload Waybill Sample" and FERC Form 423. FERC Form 580 is a biennial survey that requires responses from all jurisdictional utilities that either operate or have ownership interest in at least one steam-electric generating station with a capacity of 50 MW or greater. The STB "Carload Waybill Sample" survey collects data on transportation rates, distances shipped, and origin/destination states for commodities shipped by rail only.

The transit losses of coal calculated on the basis of weight shipped and actual receipts are estimated to be about 0.5%. Therefore, it is appropriate to neglect coal transportation losses and assign the value 1 to the efficiency parameters (multipliers) of all coal transportation arcs.

5.1.4 Coal Stocks

In order to be able to respond to sudden increases electricity demand and as insurance against a disruption in deliveries, electric power plants generally maintain a 45- to 60-day stockpile of coal [117]. Stockpiles are also built up in anticipation of strikes by coal miners and workers involved with coal shipments.

As indicated by Figure 5.1, at the end of 2002 coal stocks decrease 1.0 million short tons from the prior year, which is not a significant change. Coal stocks in the electric power sector slightly increased to totalize 142 million short tons, while coal producers and distributors and industrial consumers decreased their stocks to 39 million short tons [110].

Although data are routinely collected on coal stocks at individual power plants, it is only publicly available with a very high level of aggregation. Furthermore, information regarding storage capacities and associated costs is extremely limited. On the other hand, it is adequate to assume that coal stocks remain steady throughout the year, and consequently neglect the dynamics of coal stocks in a medium term analysis.

5.1.5 Coal Consumption

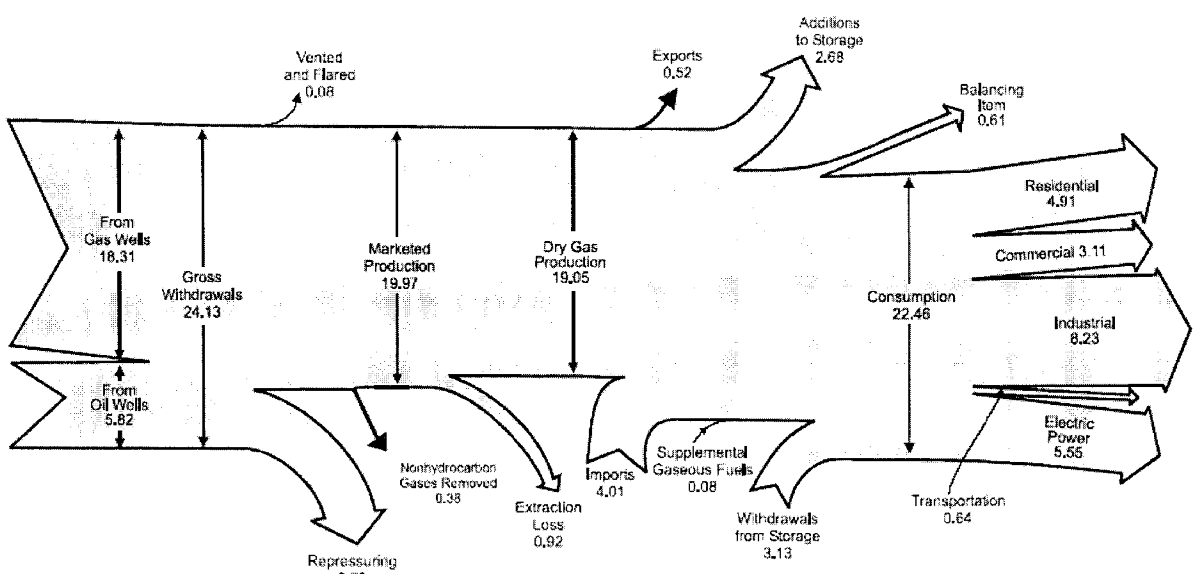
The clear majority of the coal mined in the United States is used to generate electricity. In 2002, domestic coal consumption reached 1,065.8 million short tons and electric power generators were responsible for almost 92% of total consumption (see Figure 5.1). The industrial sector (including coke plants that make coke for the iron and steel industry, foundries, and other industries) accounted for about 8%, while the commercial and residential sectors combined were responsible for less than 0.5% of total domestic consumption.

The coal suitable for making coke, called metallurgical coal or coking coal, is a different kind of coal than the coal used in the electric power sector, called steam coal. Metallurgical coal is a selected bituminous coal produced primarily in the eastern part of the country and characterized by a particularly high heat value and low ash content.

Given the relatively small fraction of the coal consumed by the industrial, commercial, and residential sectors and because it is mainly concerned with a different type of coal than the coal used to generate electricity, it is appropriate to model the coal subsystem with the central assumption that its dynamics are not affected by industrial, commercial, or residential coal consumers.

5.2 NATURAL GAS SUBSYSTEM

This section is a detailed description of the modeling assumptions for the natural gas subsystem. The nodes, arcs, and associated parameters (costs, efficiencies, and capacities) are defined. All data sources used to characterize the natural gas supply nodes, storage nodes, transshipment nodes, and associated arcs are identified and the methodology adopted to resolve data gaps is presented. Figure 5.4 gives an overview of the natural gas industry in 2002.

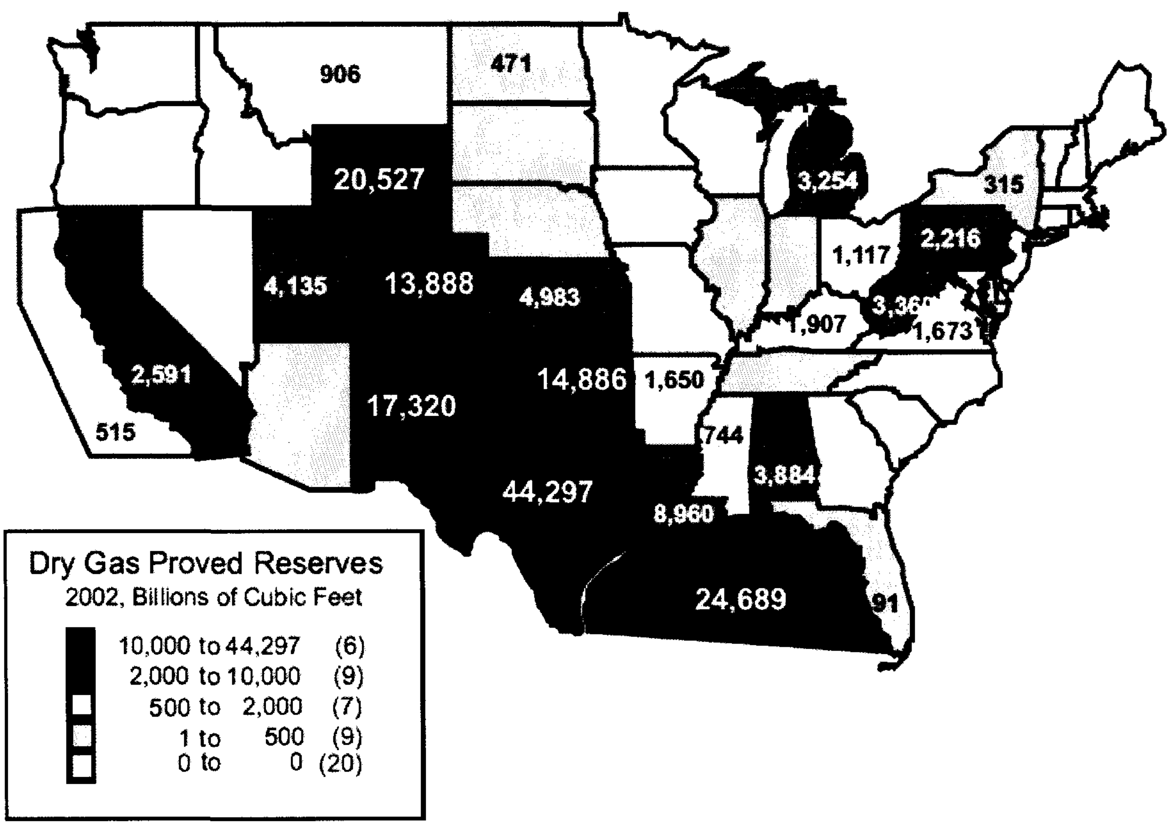


Source: Energy Information Administration

Figure 5.4 – Natural gas flow diagram, 2002 (trillion cubic feet)

5.2.1 Natural Gas Production

The EIA estimates that the United States had 186,946 billion cubic feet (Bcf) of dry natural gas[1] proved reserves as of December 31, 2002 [118]. As can be seen on the map showed in Figure 5.5, proved reserves in the lower 48 states are concentrated in relatively distinct geographical areas, namely around Texas, the Gulf of Mexico, and the Rocky Mountains. Given this distribution of natural gas deposits, those states which are located on top of a major basin have the highest level of natural gas reserves and consequently the largest potential for production. In fact, domestic natural gas production comes primarily



Source: Energy Information Administration

Figure 5.5 – Dry natural gas proved reserves

[1] Dry natural gas: Dry natural gas refers to the actual or estimated natural gas which remains after: 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and 2) any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable. Dry natural gas is also known as consumer-grade natural gas.

from the Gulf of Mexico and the states of Texas, New Mexico, Oklahoma, Wyoming, Louisiana and Colorado, which together were responsible for approximately 84% of total market natural gas production in 2002 [119]. In all, approximately 20 trillion cubic feet (Tcf) of dry natural gas were produced in 2002 from the more than 383 thousand gas wells located in 32 producing states and the Federal Offshore Gulf of Mexico. The two largest supply areas, the Gulf of Mexico and Texas, accounted for about 50% of the nation's total gas production.

Taking into account the geographical distribution of dry natural gas proved reserves and production and restricted by data availability constraints, fourteen natural gas supply regions are defined as shown in Figure 5.6.

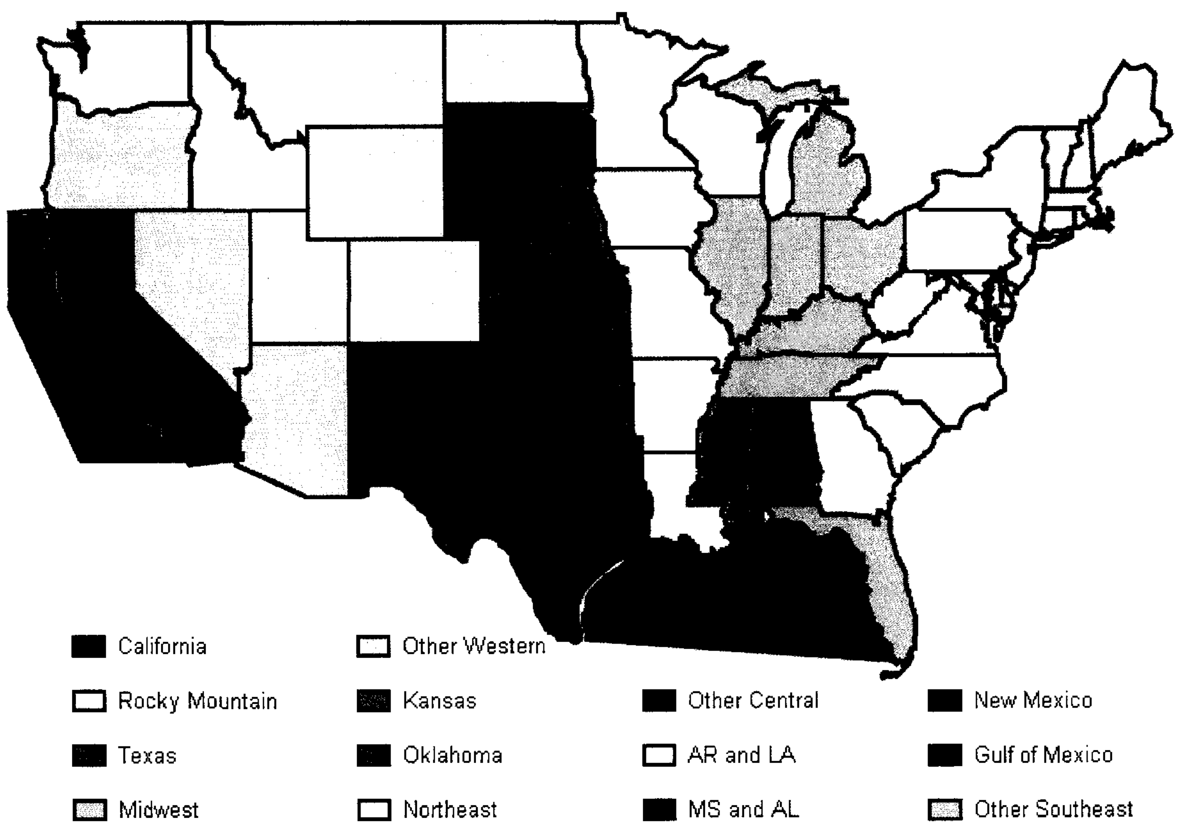


Figure 5.6 – Natural gas supply regions

For each natural gas supply region a gas supply node is defined, which means that fourteen gas supply nodes are represented in the model. Table 5.2 and Table 5.3 list these nodes and associated effective productive capacity and average wellhead price, respectively.

Table 5.2 – Monthly effective productive capacities

Supply node	Effective productive capacity (Bcf/day)											
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
California	1.117	1.111	1.107	1.105	1.096	1.089	1.084	1.079	1.077	1.077	1.079	1.077
Other Western	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Rocky Mountain	6.613	6.645	6.661	6.679	6.699	6.719	6.738	6.758	6.780	6.800	6.823	6.847
Kansas	1.651	1.644	1.636	1.627	1.619	1.612	1.606	1.599	1.594	1.590	1.586	1.582
Other Central	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
New Mexico	4.553	4.602	4.596	4.593	4.594	4.596	4.599	4.602	4.609	4.616	4.632	4.646
Texas	14.565	14.470	14.363	14.260	14.169	14.117	14.077	14.051	14.052	14.066	14.103	14.170
Oklahoma	4.736	4.717	4.693	4.671	4.650	4.638	4.628	4.625	4.624	4.632	4.644	4.659
AR and LA	4.477	4.487	4.537	4.535	4.582	4.569	4.643	4.518	4.175	4.307	4.383	4.387
Gulf of Mexico	14.621	14.552	14.465	14.371	14.265	14.198	14.145	14.099	14.083	14.068	14.082	14.131
Midwest	1.299	1.300	1.300	1.301	1.301	1.301	1.302	1.302	1.303	1.303	1.304	1.305
Northeast	1.582	1.583	1.584	1.585	1.585	1.585	1.586	1.586	1.587	1.588	1.588	1.589
MS and AL	1.538	1.554	1.549	1.547	1.547	1.547	1.547	1.547	1.548	1.550	1.554	1.557
Other Southeast	0.321	0.321	0.321	0.321	0.321	0.321	0.322	0.322	0.322	0.322	0.322	0.322

Effective productive capacity is defined as the maximum production available from natural gas wells, considering limitations of the production and gathering systems. It is a demonstrated upper limit on the amount of natural gas that can be produced that is lower than the wellhead capacity. The primary source of information for these data is the EIA Form 895, "Monthly and Annual Quantity and Value of Natural Gas Production Report." This survey collects monthly state level information concerning natural gas production that is submitted by applicable state agencies on a voluntary basis. Since reporting is voluntary and subjected to revisions, the Reserves and Production Division in EIA's Office of Oil and Gas prepares monthly estimates based on the responses obtained through this survey and other sources. The results are published in several EIA'a monthly and annual reports, such as the "Natural Gas Monthly" [120], "Monthly Energy Review" [121], "Natural Gas Annual" [119], and

"Annual Energy Review" [110]. Among the other sources of information that EIA uses to produces effective productive capacity estimates are the states and the Minerals Management Service (MMS) websites. For instance, the state of Texas website, more specifically the Railroad Commission of Texas, posts well-level monthly data on drilling and production [122]. Similarly, the Colorado Oil and Gas Conservation Commission of the Colorado Department of Natural Resources has a database system available on their website that allows monthly production data inquiries by well, facility, operator, county, or field [123]. Monthly well-level data regarding gas production on federal lands, including the Gulf of Mexico and the California Federal Offshore region, is available through the MMS website of the U.S. Department of the Interior [124]. MMS is the federal agency that manages the nation's natural gas, oil, and other mineral resources on the outer continental shelf.[1] Finally, for those states for which the effective productive capacity is not available, it is assumed to be equal to the wellhead capacity.

The wellhead price is the value of the natural gas at the site of production. In general, it is considered to be the sales price or the price received by natural gas producers for marketed gas, which includes charges for natural gas plant liquids subsequently removed from the gas, gathering and compression charges, and state charges. This information is collected annually, at the state level, through the EIA Form 176, "Annual Report of Natural and Supplemented Gas Supply and Disposition," and is publicly available. In addition, the EIA estimates monthly national average wellhead prices and publishes the results on the "Monthly Energy Review" [121]. To obtain the wellhead prices presented in Table 5.3, first the annual weighted average wellhead price are calculated for each supply node, weighted by the marketed production of each state for those supply nodes that aggregate more than one state. Then, monthly values are derived to reflect the monthly national pattern. This is based on the underline assumption that the monthly average wellhead prices is independent of the location, which is imposed by to lack of more detailed data. For the Gulf of Mexico region, monthly prices are assumed to be equal to the national average monthly prices.

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[1] Outer continental shelf: Outer continental shelf refers to the submerged lands, subsoil, and seabed lying between the states' seaward jurisdiction and the seaward extent of federal jurisdiction.

Table 5.3 – Monthly average wellhead prices

Supply node	Average wellhead price (2002 $/Mcf)											
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
California	2.48	2.17	2.38	2.91	2.91	2.93	2.89	2.73	2.94	3.21	3.56	3.92
Other Western	3.06	2.68	2.94	3.60	3.60	3.62	3.57	3.38	3.64	3.97	4.39	4.85
Rocky Mountain	2.15	1.88	2.06	2.53	2.53	2.54	2.51	2.37	2.55	2.79	3.09	3.40
Kansas	2.21	1.94	2.13	2.60	2.60	2.62	2.59	2.44	2.63	2.87	3.18	3.51
Other Central	2.15	1.88	2.06	2.53	2.53	2.54	2.51	2.37	2.55	2.78	3.08	3.40
New Mexico	2.27	1.99	2.18	2.67	2.67	2.69	2.65	2.51	2.70	2.95	3.26	3.60
Texas	2.68	2.35	2.57	3.15	3.15	3.17	3.13	2.96	3.18	3.47	3.85	4.25
Oklahoma	2.49	2.18	2.39	2.93	2.93	2.95	2.91	2.75	2.96	3.23	3.58	3.95
AR and LA	2.83	2.47	2.71	3.32	3.32	3.34	3.30	3.12	3.36	3.66	4.06	4.47
Gulf of Mexico	2.56	2.24	2.46	3.01	3.01	3.03	2.99	2.83	3.04	3.32	3.68	4.06
Midwest	2.38	2.08	2.28	2.80	2.80	2.82	2.78	2.63	2.83	3.08	3.42	3.77
Northeast	2.57	2.25	2.47	3.02	3.02	3.04	3.00	2.84	3.05	3.33	3.69	4.07
MS and AL	2.87	2.51	2.75	3.37	3.37	3.39	3.35	3.16	3.40	3.71	4.12	4.54
Other Southeast	2.56	2.24	2.46	3.01	3.01	3.03	2.99	2.83	3.04	3.32	3.68	4.06

To account for the extraction losses (difference between the marketed production and dry production), an efficient parameter or loss factor is assigned to each supply node. Table 5.4 lists the supply nodes and the associated loss factors. These factors are derived from data collected via the EIA Form 895, "Monthly and Annual Quantity and Value of Natural Gas Production Report," and publicly available through the "Natural Gas Annual" report [119].

The average heat value of the natural gas delivered to the power plants is estimated from the data available through the FERC Form 423, "Cost and Quality of Fuels for Electric Plants." It is assumed to be equal to 1,021 Btu per cubic foot. The sulfur content is negligible.

Table 5.4 – Extraction losses

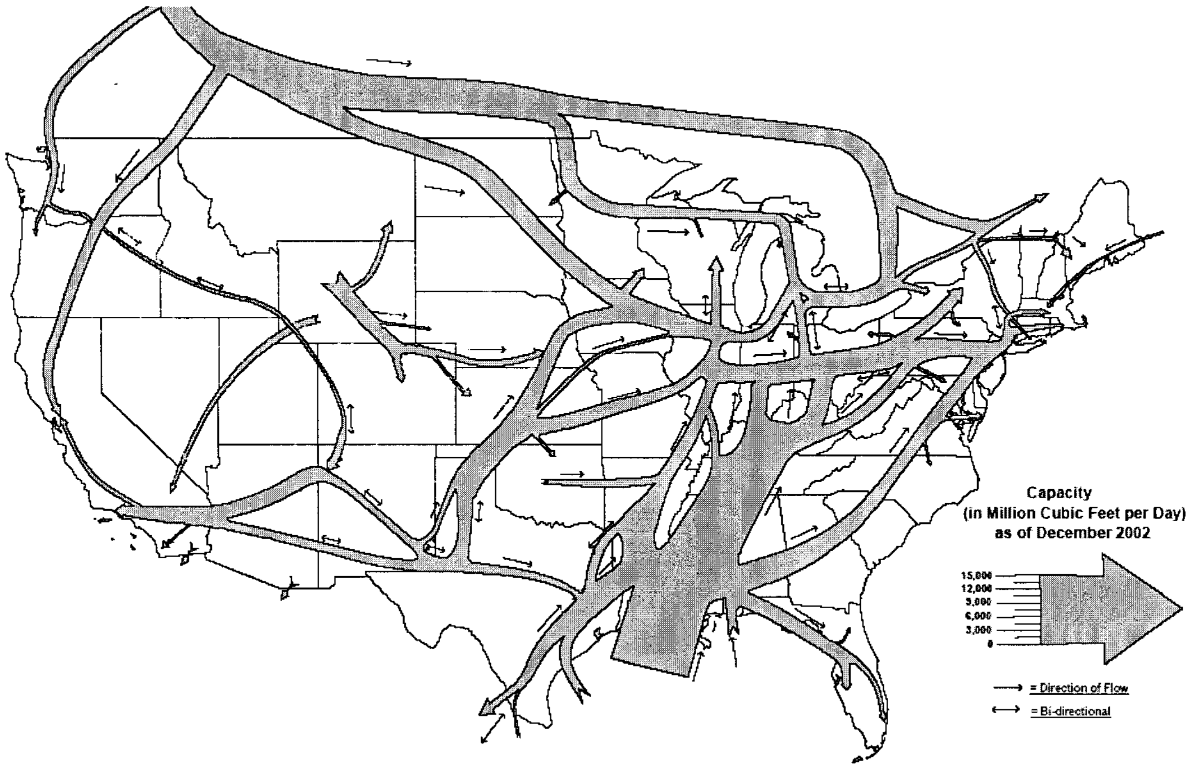
Supply node	Loss factor	Supply node	Loss factor
California	0.96	Oklahoma	0.95
Other Western	1.00	AR and LA	0.90
Rocky Mountain	0.96	Gulf of Mexico	1.00
Kansas	0.91	Midwest	0.99
Other Central	1.00	Northeast	0.98
New Mexico	0.93	MS and AL	0.93
Texas	0.93	Other Southeast	0.84

5.2.2 Natural Gas Transmission

According to the Interstate Natural Gas Association of America (INGAA), at the end of 2002 there were 85 companies in the United States operating about 212,000 miles of interstate natural gas pipelines. This pipeline capacity is capable of transporting over 113 billion cubic feet (Bcf) per day from producing regions to consuming regions [125]. Figure 5.7 depicts the interstate and selected intrastate pipeline systems, while Figure 5.8 shows the major pipeline transportation corridors.

Source: Energy Information Administration

Figure 5.7 – Interstate and selected intrastate pipeline systems



Source: Energy Information Administration

Figure 5.8 – Major pipeline transportation corridors

Given the complexity of this system and data availability restrictions, representation of the actual physical system is prohibitive. Moreover, a simplified approach is adequate to accomplish the proposed objectives, and is in accordance with the need to develop an easy to understand, compact and speedy model.

The lower 48 states are divided into six transmission regions: 1-Western, 2-Central, 3-Midwest, 4-Northeast, 5-Southwest, and 6-Southeast. This geographical aggregation is based on the federal regions originally defined by the Bureau of Labor Statistics and on major interstate pipeline flows, and is further determined by data availability limitations. Each region contains one transshipment node, which represents a junction point for flows coming into and out of the region. Arcs connecting the transshipment nodes represent interregional flows. Figure 5.9 shows the transshipment nodes and interregional arcs, along with four U.S.-Canada crossing border nodes and a dummy Canadian supply node. In accordance with what is described in the next section, two U.S.-Mexico crossing border arcs and a dummy Mexican demand node are also depicted.

Figure 5.9 – Natural gas transportation model

Each of the interregional arcs represents an aggregation of pipelines that are capable of moving gas from one region into another. Bidirectional flows are allowed in cases where the aggregation includes some pipelines flowing one direction and other pipelines flowing in the opposite direction, or in cases where the direction of flow can shift within a single pipeline system. Arcs leading to the dummy Mexican demand node represent exogenously determined exports and arcs coming from the dummy Canadian supply node represent imports. Flows are further represented by establishing arcs from the supply nodes discussed in section 5.2.1 to the correspondent transshipment node that results from overlapping the natural gas supply regions presented in Figure 5.6 with the transmission regions defined in Figure 5.9. Similarly, arcs are also established between the transshipment nodes and storage nodes and from the transshipment nodes to demand nodes, as will be addressed in section 5.2.4 and section 5.2.5, respectively. Table 5.5 lists the interregional arcs with their associated capacities and costs.

Table 5.5 – Interregional arc capacities and costs

Receiving region	Sending region	Capacity (MMcf/d)	Cost (2002 $/Mcf)
Western	Canada	4,643	1.28
	Central	1,461	1.61
	Southwest	5,924	1.10
Central	Canada	3,980	0.15
	Midwest	3,299	0.34
	Southwest	8,660	0.13
	Western	385	0.26
Midwest	Canada	3,266	0.40
	Central	15,187	0.92
	Northeast	2,089	0.44
	Southeast	9,267	0.09
Northeast	Canada	3,054	0.88
	Midwest	4,886	1.62
	Southeast	5,760	1.08
Southwest	Central	2,975	0.96
	Southeast	405	0.13
Southeast	Midwest	219	1.18
	Northeast	582	0.99
	Southwest	22,001	0.97

The efficiency parameter is set to 0.97 to all interregional arcs. This loss factor represents the pipeline fuel, i.e., the gas consumed in the operation of pipelines, primarily in compressors. It is derived from data published on the "Natural Gas Annual" [119].

Capacity data are derived from the FERC Form 549B, "Capacity Report", 18 CFR Section 284.13. Every year, interstate pipeline companies are required to file this capacity report with FERC, showing the pipeline's peak day capacity. These data are available in various EIA publications at different levels of aggregation, and in most pipeline companies' websites.

The interregional arcs' costs represent the transmission markup, calculated as the difference between the annual average price of natural gas delivered to electric power plants and the annual average wellhead or imports price. This transmission markup represents the average price that electric utilities pay for all services required to move gas from the wellhead or the U.S.-Canada border to their generators, assuming that transmission rates vary with the volumes delivered. The prices and quantities of natural delivered to power plants are available from FERC Form 423, "Cost and Quality of Fuels for Electric Plants." These data are aggregated to the level of the regions defined in Figure 5.9. Since generator-level data are aggregated to network regions, the composite price of the natural gas delivered to power plants at the region-level is the volumetric-weighted average of the generator-level data. The average wellhead prices presented in Table 5.3 are also aggregated to network regions, weighted by the effective productive capacities given in Table 5.2. The transmission markups derived under this methodology indirectly capture the complexity of many aspects involved in pricing natural gas transportation services.

Alternatively, the transportation rates along the interregional arcs could have been estimated by computing the average tariff charges over all pipelines represented along an arc. While trading and pricing of gas as a commodity have been largely deregulated, transportation tariffs remain tightly regulated by FERC. Pipeline companies must seek approval from the regulatory commission for proposed rates, which are based on estimated annual operating and maintenance expenses plus a reasonable return on investment [126]. Individual company tariff data are publicly available through the FERC Automated System for Tariff Retrieval, commonly known as FASTR. FASTR is a computer-based software and data system that provides free electronic access to all interstate pipelines' tariffs [127]. Despite the fact that data are available, this approach was not adopted, because tariffs do not properly reflect the transportation charges incurred by electric utilities. The reasons to support this statement are the following:

- Tariffs are the maximum rates authorized by FERC, which may be very different from the actual prices paid by shippers on interstate pipeline companies. Regulatory reform and new legislation has restructured some aspects of the natural gas industry, including deregulation of wellhead prices and pipeline unbundling, which has increased competition in the marketplace. Suppliers have a greater flexibility in setting the terms of sale and buyers have more choices for purchasing gas and pipeline transmission. As a result, pipeline companies often offer discount rates for their services (in particular to large-volume energy consumers, such as electricity generators), resulting in customers paying substantially less than the tariffs approved by FERC.

- Electric generators which require guaranteed service are designated as firm customers, in contrast with interruptible ones. Firm rates are divided into reservation charges (fixed costs) and usage fees or commodity charges (variable costs). While this is an important consideration in determining rates, there is insufficient information to accurately model all the aspects of firm service contracts, namely the distinction between reservation charges and usage fees.

- Electric generators holding capacity rights on interstate pipelines may release that capacity in the secondary market if they do not need it, lowering the overall cost of shipping gas. The revenues obtained from that capacity release are not reflected in the tariffs.

- New players (e.g., marketers of spot gas and brokers for pipeline capacity) have entered the market, creating increasingly complex links connecting suppliers with end users. There are two distinct markets for natural gas: the spot market and the futures market. Under the spot market natural gas is traded at different locations called hubs or market centers. The prices at which natural gas trades differs across the major hubs and is set by market forces (supply and demand) at that particular point. The futures market consists of buying and selling natural gas under agreements established for delivery of the physical commodity in the future. Natural gas futures are traded on New York Mercantile Exchange (NYMEX) and reflect the price of natural gas for physical delivery at the Henry Hub.

5.2.3 International Natural Gas Trade

Regarding the lower 48 states, foreign natural gas trades consist of imports/exports with Canada and Mexico via the North American pipeline network and liquefied natural gas (LNG[1]) imports from nonadjacent countries by way of oceanic vessels.

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[1] LNG: Liquefied natural gas is obtained through the cooling of natural gas to -260 degrees Fahrenheit at atmospheric pressure. Natural gas liquefaction reduces its volume by a fraction of 600 to one, which allows long distance transportation and easier storage.

Canada is by far the largest foreign supplier of natural gas to the United States. In 2002, it provided enough exports through pipeline transportation to meet almost one-sixth of U.S. consumption. Canada's vast gas reserves, couples with its relatively small demand, provide the United States with a reliable source of natural gas imports. Natural gas is moved from Canada's major producing regions in British Columbia, Alberta, and Nova Scotia, to U.S. markets in the West, Upper Midwest, and Northeast, through a highly integrated pipeline network. There are 25 entry/exit points across the U.S.-Canadian border, with Port of Morgan, Montana, and Eastport, Idaho, being the U.S. receipt points with the largest volumes for imports from Canada. Under the terms of North American Free Trade Agreement (NAFTA), producing companies operate freely across the U.S.-Canadian border, which means that the process by which Canadian gas flows to the United States is essentially the same process as that for domestic supplies. As a result, natural gas imports from Canada are treated endogenously. The crossing border points are aggregated into four nodes (Western, Central, Midwest, and Northeast), each of which is connected to a dummy Canadian supply node through capacitated arcs that represent the aggregated capacity limitations of the pipelines associated to each of the crossing border nodes. Flows in the Western region include points of entry in the state of Washington and Idaho. Flows in the Central region include points of entry in Montana and North Dakota. Points of entry in Minnesota and Michigan are included in the Midwest region. Points of entry in New York, Vermont, New Hampshire, and Maine are included in the Northeast region. Table 5.6 lists this pipeline aggregation and associated capacities. The capacity data are obtained from EIA's reports (e.g., [128]) that present aggregate data derived from the EIA's Natural Gas Pipeline Capacity Database. Table 5.7 shows the monthly average prices of natural gas imported from Canada. These data are derived from the Canadian National Energy Board (NEB[1]) Form 15, "Natural Gas Export Reporting." The average heat value of the natural gas imported from Canada is assumed to be 1,022 Btu per cubic foot, as published in Table A4 of the "Annual Energy Review 2003" [129]. The sulfur content is neglected.

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[1] NEB: The National Energy Board is the Canadian federal regulatory agency that oversees, among other aspects of the Canadian energy industry, the exports and imports of natural gas.

Table 5.6 – U.S.-Canada crossing border nodes

Crossing border node	Aggregated Pipelines	Capacity (MMcf/day)
Western	Sumas, WA Eastport, ID	4,643
Central	Babb, MT Havre, MT Port of Del Bonita, MT Port of Morgan, MT Sweetgrass, MT Whitlash, MT Portal, ND Sherwood, ND	3,980
Midwest	International Falls, MN Noyes, MN Warroad, MN Detroit, MI Marysville, MI St. Clair, MI	3,266
Northeast	Champlain, NY Grand Island, NY Massena, NY Niagara Falls, NY Waddington, NY Highgate Springs, VT North Troy, VT Pittsburg, NH Calais, ME	3,054

Table 5.7 – Monthly average prices of U.S. imports from Canada

Crossing border node	Average prices (2002 $/Mcf)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Western	2.79	2.25	2.50	3.15	3.03	2.62	2.20	2.16	2.69	3.23	3.83	3.98
Central	2.42	2.01	2.40	3.15	3.14	3.02	2.90	2.63	2.96	3.60	4.04	4.09
Midwest	2.62	2.34	2.62	3.35	3.26	3.04	2.69	2.68	2.99	3.52	3.88	4.07
Northeast	3.01	2.67	3.01	3.60	3.64	3.59	3.41	3.30	3.60	4.01	4.42	4.66

In contrast with Canadian gas supply, natural gas trade with Mexico is a highly complex issue, characterized by considerable uncertainty and significantly influenced by noneconomic factors. As a result, natural gas exports are represented as fixed demand according to an exogenously specified schedule. In all, natural gas is exported to Mexico at eleven points on the U.S.-Mexico borders in Texas, Arizona, and California. For modeling purposes, one dummy Mexican demand node is defined, connected by two arcs to the U.S. pipeline transportation network. One of these arcs represents all the crossing border flows from California and Arizona and the other arc aggregates all the crossing border flows from Texas. Table 5.8 lists this pipeline aggregation and

Table 5.9 presented the monthly average volumes of natural gas exported to Mexico. These data are based on monthly values published by the Office of Fossil Energy in the "Natural Gas Import & Export Regulations – Quarterly Reports" [130].

Table 5.8 – Mexican crossing border arcs

Crossing border arc	Aggregated Pipelines
From CA and AZ	Douglas, AZ Calexico, CA Obilgy Mesa, CA Otay Mesa, CA
From TX	Alamo, TX Clint, TX Eagle Pass, TX El Paso, TX Hidalgo, TX McAllen, TX Penitas, TX

Table 5.9 – Monthly average volumes of U.S. exports to Mexico

Crossing border arc	Average exported volume (MMcf)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
From CA and AZ	2,724	2,508	3,367	2,344	3,202	4,323	5,701	5,829	5,381	4,135	3,325	3,319
From TX	8,881	7,463	14,846	16,777	19,598	20,625	21,869	23,093	22,099	22,179	17,940	19,795

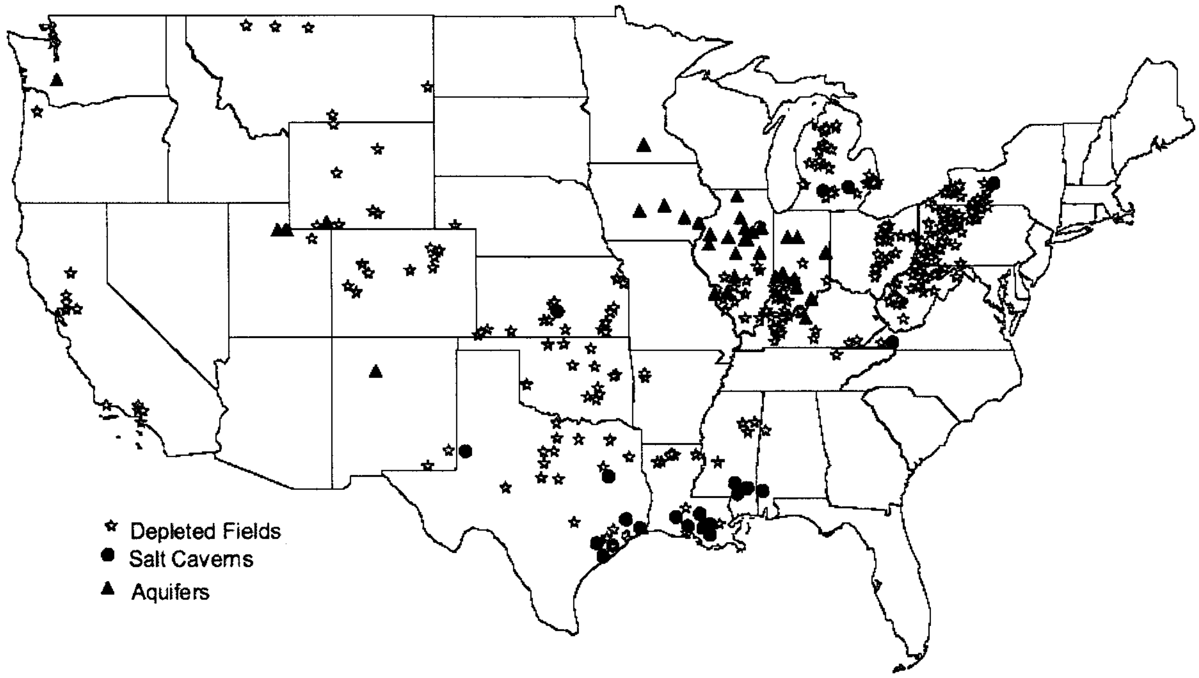
In 2002, LNG imports came primarily from Trinidad and Tobago (66%). Other LNG supplier countries were Qatar (15%), Algeria (12%), Nigeria (4%), Brunei (1%), Oman (1%), and Malaysia (1%). The operational border crossing locations were Elba Island, GA, Lake Charles, LA, and Everett, MA. Although the United States is increasing its reliance on LNG from other countries to meet demand growth, LNG imported in 2002 represented less than 1% of total U.S. consumption [119], due to the high costs of transportation and liquefaction. Given this small share and the increased complexity that it would bring into the model, LNG imports are not considered.

5.2.4 Natural Gas Storage

Unlike in the case of coal, natural gas storage plays a vital role in maintaining the reliability of supply needed to meet demand [131]. First, natural gas storage is important to meet the traditionally seasonal demand – according to the American Gas Association (AGA), approximately 20% of natural gas consumed during the winter heating season comes from underground storage – and to respond to sudden demand increases due to non-weather related factors. Secondly, it serves as insurance against any disruptions that may affect the production or delivery of natural gas.

Natural gas is typically stored underground, in large storage reservoirs. There are mainly three types of underground storage: depleted natural gas and oil fields, aquifers, and salt caverns [132]. Depleted reservoir storage facilities result from the use of a depleted natural gas or oil field that is reconditioned into a storage field. Conversion of a field from production to storage takes advantage of existing infrastructures (wells, gathering systems, and pipeline connections), which reduces its development costs. In areas where there are no nearby depleted fields, natural water reservoirs (aquifers) may be converted to gas storage facilities. Salt caverns are formed out of existing underground salt domes or salt bed deposits. Figure 5.10 shows the location of the more than 400 active underground storage facilities in the contiguous United States.

Although underground storage facilities are presented in 30 of the lower 48 states, they are most concentrated in the consuming northeast region of the country, i.e., near market centers that do not have ready supply of locally produced natural gas. Approximately 40% of the capacity is clustered in four states: Michigan, Illinois, Pennsylvania, and Ohio. Their distribution patterns reflect varying geographic advantages. Because of their wide availability, depleted oil and gas reservoirs are the most commonly used underground storage sites. At the end of 2002, depleted fields accounted for 82% of total underground storage capacity in the United States. Aquifers there are used for gas storage are found primarily in the Midwest and represented 15% of total underground capacity. Salt cavern storage facilities account for the remaining 3% of capacity and are mainly located along the Gulf Cost [119].



Source: Energy Information Administration

Figure 5.10 – Underground Natural Gas Storage Facilities

For each of the transmission regions presented in Figure 5.9, one storage node is defined. This means that six natural gas storage nodes are represented in the model. Each of these nodes denotes an aggregation of all the natural gas storage facilities in that region. Arcs connect each storage node with its correspondent transshipment node and also establish the connection in time between two consecutive periods. Incoming arcs (from the transshipment node to the storage node) represent storage injections and outgoing arcs (from the storage node to the transshipment node) represent storage withdrawals. Storage also serves as the primarily link between two consecutive periods, with the arcs establishing this connection in time representing the flow of natural gas that is carried over from one period to another. Figure 5.11 shows a simplified example of how storage nodes connect with transshipment nodes and across time.

Table 5.10 lists the storage nodes and the parameters that characterize the arcs connecting the storage nodes with the transshipment nodes and the arcs connecting storage nodes in consecutive time periods.

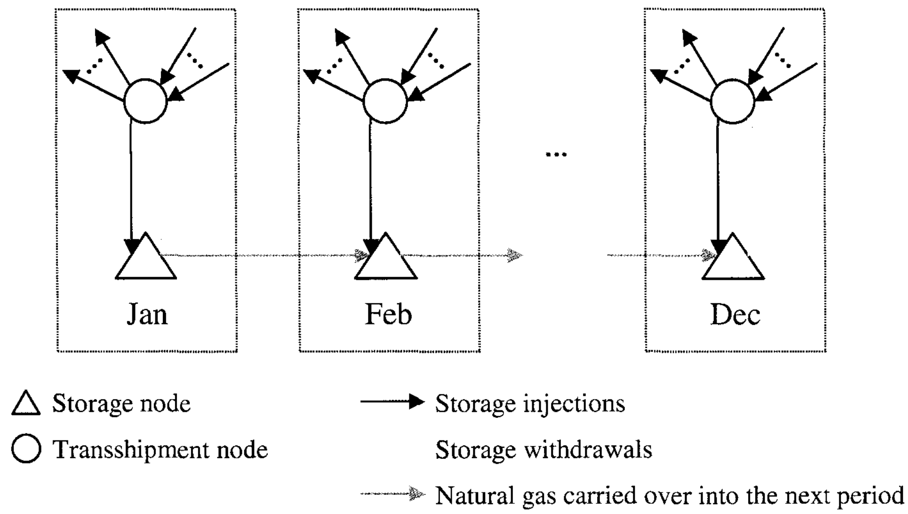


Figure 5.11 – Illustration of the storage links

Table 5.10 – Natural gas storage nodes

Storage node	Cushion gas Volume (MMcf)	Cushion gas Percent of total capacity	Total capacity (MMcf)	Withdrawal capacity (MMcf/day)	Injection capacity (MMcf/day)	Initial volume (MMcf)	Final volume (MMcf)
Western	262,513	49.8	526,810	8,305	4,153	457,108	477,713
Central	783,072	57.8	1,353,590	6,709	3,355	990,592	1,040,705
Midwest	1,548,331	58.2	2,660,285	24,734	12,367	2,272,959	2,298,445
Northeast	766,405	45.3	1,691,573	13,030	6,515	1,242,571	1,259,505
Southwest	769,041	43.1	1,783,318	23,830	11,915	1,392,155	1,310,118
Southeast	219,367	60.1	364,949	6,209	3,105	326,832	328,982

Cushion gas, or base gas, is the volume of gas that remains in the storage facility at all times to provide the necessary pressurization to extract the remaining gas at acceptable rates. The total capacity refers to the maximum volume of gas that can be stored in the facility. In terms of the network flow representation, cushion gas and total capacity represent the lower and upper bound, respectively, of the arcs connecting storage nodes in consecutive time periods. The difference between the total capacity and the cushion gas is called the working gas capacity. Working gas is the amount of natural gas that is actually available for withdrawal. Base gas requirements are a function of the physical characteristics of the underground storage facility. For example, in depleted reservoirs (the most common type of underground storage), about half of the natural gas in the formation must be kept as cushion gas in order to maintain pressure. Aquifers typically require more cushion gas than do depleted reservoirs, which can be as high as 80% of the total gas volume. Because salt caverns are essentially high-pressure underground storage formation, their cushion gas requirements are the lowest of all three storage types, representing only about one third of total gas capacity [133].

Withdrawal capacity (also referred to as deliverability) is the amount of gas that can be delivered from a storage facility on a daily basis. Injection capacity is the complement of withdrawal capacity, representing the amount of gas that can be injected into a storage facility on a daily basis. Deliverability and injection rates depend, among other factors, on the physical characteristics of the storage site. In particular, the injection into and withdrawal from salt caverns are typically much higher than for either aquifers or depleted reservoirs [134], which justifies the high rates for the southwest region.

The initial and final volumes of gas represent the amount of gas that exists in storage at the beginning of the simulation period and the required inventory at the end of the simulation period, respectively. The consideration of the required volumes of gas in storage at the end of the simulation is necessary to avoid boundary distortions.

Except for injection capacity, data presented in Table 5.10 are derived from EIA Form 191, "Monthly Underground Natural Gas Storage Report." This survey form collects, among other things, data on total capacity, base gas, working gas, and maximum deliverability, by reservoir and storage facility, from all underground natural gas storage operators. These data are aggregated and published in the "Natural Gas Monthly," at state and regional levels [120]. Injection rates at the storage, state, regional, or even national level are unavailable from EIA or any other publicly available source. Based on sporadic information characterizing specific storage facilities, the injection capacity is estimated to be roughly half of the withdrawal capacity. Injection data are hence derived by dividing the withdrawal capacity data by two. This procedure is very limited by the availability of data.

The storage cost of service represents the charges applied for storage, injections, and withdrawals. Like interstate pipeline tariffs, storage rates are regulated by FERC and are publicly available through FASTR. Because of reasons similar to those that prevent the use of pipeline tariffs to estimate transportation rates (in particular, because storage costs are often based on negotiated rates), storage tariffs are not used to derive storage charges.

Instead, and due to the lack of publicly available information needed for a more detailed characterization of the storage costs, a fixed storage fee of 0.5 \$/Mcf is applied along arcs leaving the storage nodes and connecting to the transshipment nodes, i.e., along the arcs that represent storage withdrawals. This value is based on the findings of a research study done by Simmons & Company International [135].

5.2.5 Natural Gas Consumption

In contrast with coal (where the clear majority of the domestic consumption is used to generate electricity), natural gas is used primarily for heat, in commercial and residential settings, and in the industry. In 2002, domestic natural gas consumption reached 22.46 trillion cubic feet and electric power generators accounted for almost 25% of total consumption (see Figure 5.4). Industrial, residential, commercial, and transportation demand sectors were responsible for approximately 37%, 22%, 14%, and 3% of domestic consumption, respectively [110].

For modeling purposes, natural gas consumption levels for all non-electric power sectors are exogenously provided and treated as combined fixed demands assigned to the transshipment nodes. In other words, each transshipment node is assigned a demand, which is equal to the amount of natural gas consumed by the aggregation of the residential, commercial, industrial, and transportation sectors in that transmission region. The demand pattern is mainly determined by the highly weather-sensitive residential and commercial markets. Table 5.11 lists these non-electric demands. These data are derived by first aggregating state-level data into regional-level, and then subtracting the monthly natural gas delivered to electric power consumers to the monthly natural gas delivered to all consumers, for each region. Monthly data, by end-use sector, are gathered through the EIA Form 857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers," and are published at the state level in the "Natural Gas Monthly" reports [120].

Alternatively, the natural gas consumed by the non-electric power sectors could be represented by arcs connecting the transshipment nodes with non-electric demand nodes for each region. In this situation, the cost parameter associated to each of these arcs would represent the markup charged by local distribution companies (LDC) for the distribution of natural gas from the city gate to the end users. Likewise, capacity limits would represent an aggregation of the intrastate and LDC pipeline capacities. However, since the flows along these arcs would not be decision variables, the capacity and cost parameters would not influence the solution.

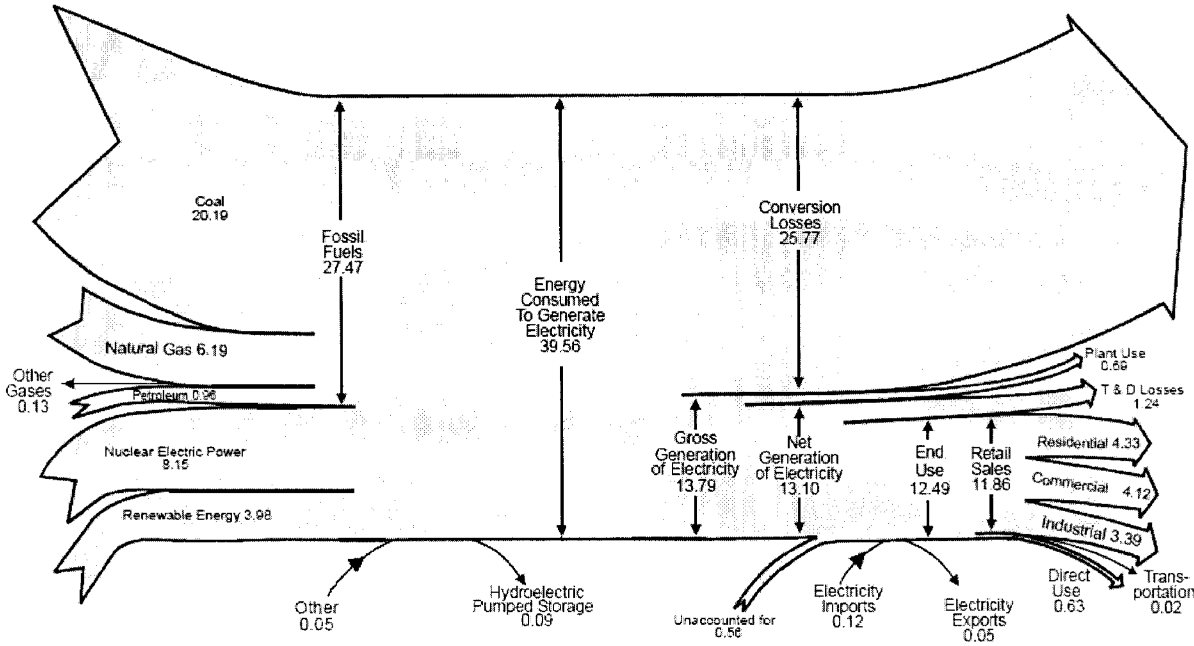
Table 5.11 – Monthly natural gas consumed by all non-electric power end-user sectors

Trans-shipment node	Non-electric demand (MMcf)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Western	245,731	208,811	204,349	166,684	150,318	129,838	131,898	134,015	129,036	152,163	164,120	209,685
Central	195,837	174,693	170,421	115,710	84,408	64,733	69,285	67,397	69,574	98,736	141,929	177,265
Midwest	500,857	449,514	449,967	331,446	238,473	169,548	151,555	151,098	149,409	251,707	372,940	502,635
Northeast	378,872	354,341	326,962	238,758	177,578	136,279	123,094	125,679	126,621	172,749	279,209	398,804
Southwest	394,781	359,575	353,993	341,193	293,142	293,695	290,833	281,671	263,739	268,710	299,110	349,909
Southeast	210,265	187,294	174,412	125,400	105,591	96,165	93,063	93,442	92,953	108,494	145,039	202,658

Natural gas consumption by the electric power sector is represented by establishing arcs from each transshipment node to the gas-fired power plants in that transmission region. Costs related with the delivery of natural gas to electricity generating plants are indirectly captured by the transmission markups defined for the interregional arcs. Therefore, the costs associated with the arcs linking transshipment nodes to electric power plants are zero. Likewise, capacity limitations and distribution losses are assumed to be captured by the transmission network. Hence, capacity and efficiency parameters of the arcs connection the transshipment nodes to the power plants are set to infinite and one, respectively.

5.3 ELECTRICITY SUBSYSTEM

This section is a detailed description of the modeling assumptions for the electricity subsystem. The nodes, arcs, and associated parameters (costs, efficiencies, and capacities) are defined. All data sources used to characterize the model regions, the electric power plant nodes, and associated arcs are identified. Figure 5.12 gives an overview of the electric power industry in 2002.

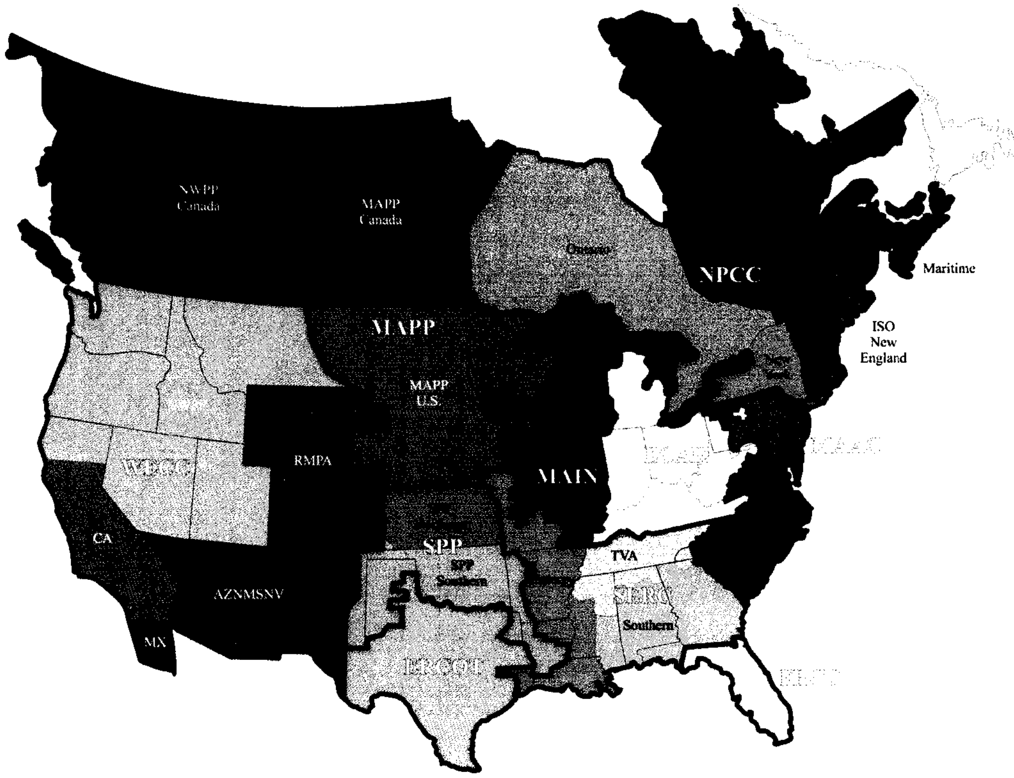


Source: Energy Information Administration

Figure 5.12 – Electricity flow diagram, 2002 (quadrillion Btu)

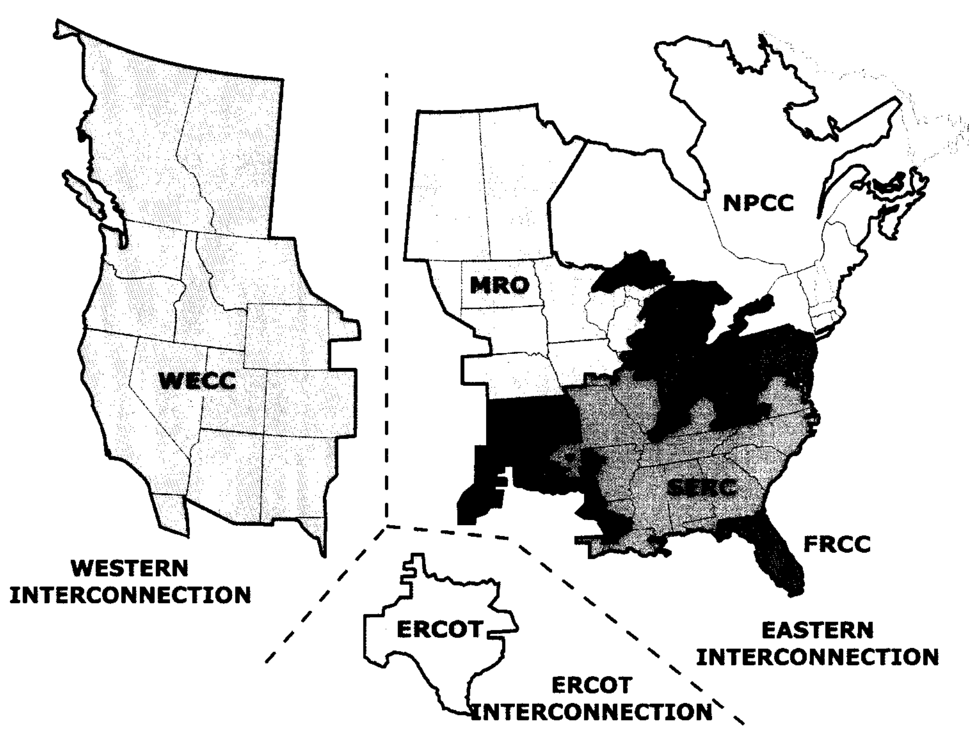
5.3.1 Electricity Model Regions

The electric power sector of the integrated energy system is modeled at a regional level. The regions considered are the 2002 existing NERC regions and subregions in the contiguous United States, with exception of the distinction between the Northern and Southern subregions of the Southwest Power Pool (SPP) region. Figure 5.13 depicts all NERC regions and subregions. This aggregation level is based on the topology of the electrical grid and operating constraints, such as transmission bottlenecks, and is an adequate simplification of the physical and institutional complexity of the electric power industry. The boundaries of the NERC regions and subregions follow the service areas of the electric utilities in the region, which do not necessarily follow state boundaries. This geographic representation also facilitates collection of data, which are generally available at this level. Although facility owners and system operators collect electrical data at specific points on the grid called buses, federal data collection agencies (e.g., FERC, EIA, and DOE) aggregate owner and operator information and make most data available only up to the NERC regions and subregions level, for confidentiality reasons. In addition, this aggregation level keeps the optimization problem and the computational time within acceptable limits.



Source: North American Electric Reliability Council (as of September 2003)

Figure 5.13 – NERC regions and subregions

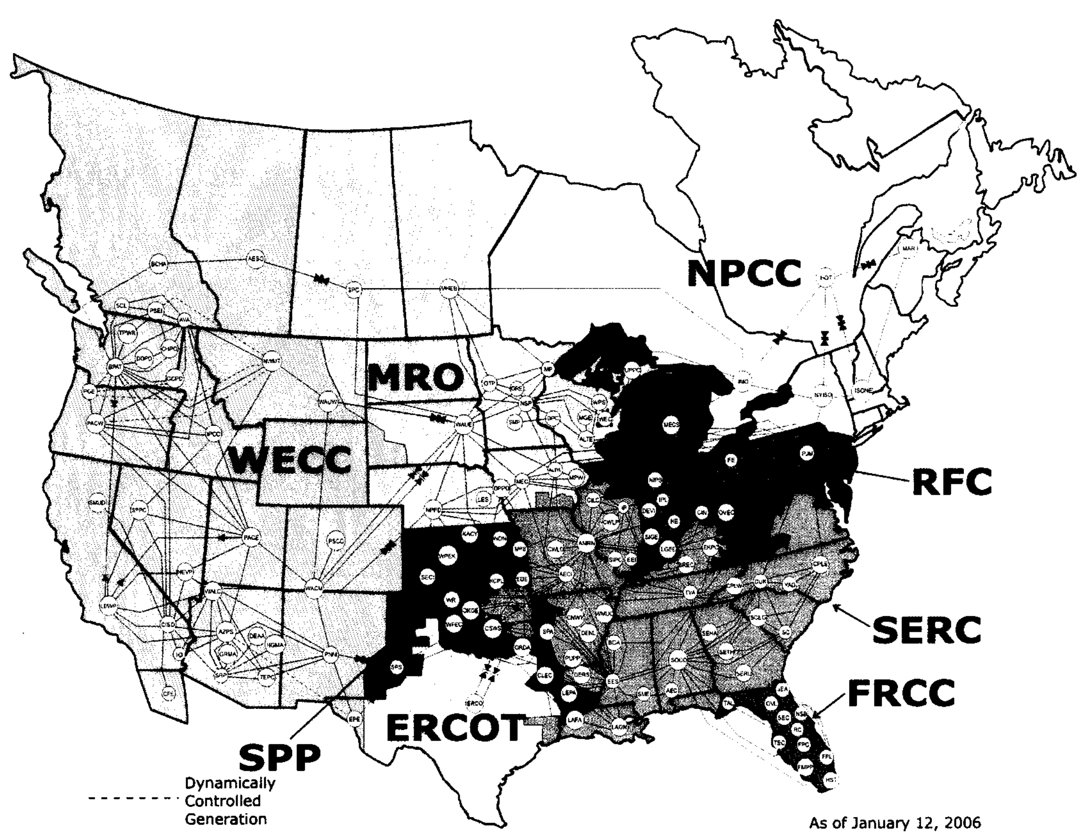


Source: North American Electric Reliability Council (as of May 2006)

Figure 5.14 – NERC regions and interconnections

At the highest level of electrical control hierarchy, data are distinguished among the three major synchronized interconnections within the United States: the Eastern interconnection, Texas (Electric Reliability Council of Texas or ERCOT), and the Western interconnection (Western Electricity Coordinating Council or WECC). Below the interconnection level is the NERC region and subregion level. Each NERC region is a voluntary association of interconnected transmission systems and generators that jointly plan, schedule, and operate to ensure the reliability of the bulk electric system in their region. Figure 5.14 depicts the NERC interconnections and current regions.

NERC regions include multiple balancing authorities (or power control areas), where a balancing authority consists of one or more electric utilities capable of regulating their generation and maintain a schedule of electricity flows. There are more than 130 balancing authorities. Figure 5.15 shows the current NERC regions and balancing authorities [136]. Finally, the fine disaggregation level would be the bus level, where a bus represents a connection for two or more electrical circuits.



Source: North American Electric Reliability Council

Figure 5.15 – NERC regions and control areas

5.3.2 Electric Power Transmission

Although the connections between the three major interconnections are very weak, virtually all U.S. utilities are interconnected with at least one other neighboring utility. Figure 5.16 depicts the complex North American high-voltage transmission system. As the map shows, the transmission grid does not conform to state or even national borders. The North American area served by NERC members is made up of over 200,000 miles of high-voltage (230 kV and above) transmission circuits.

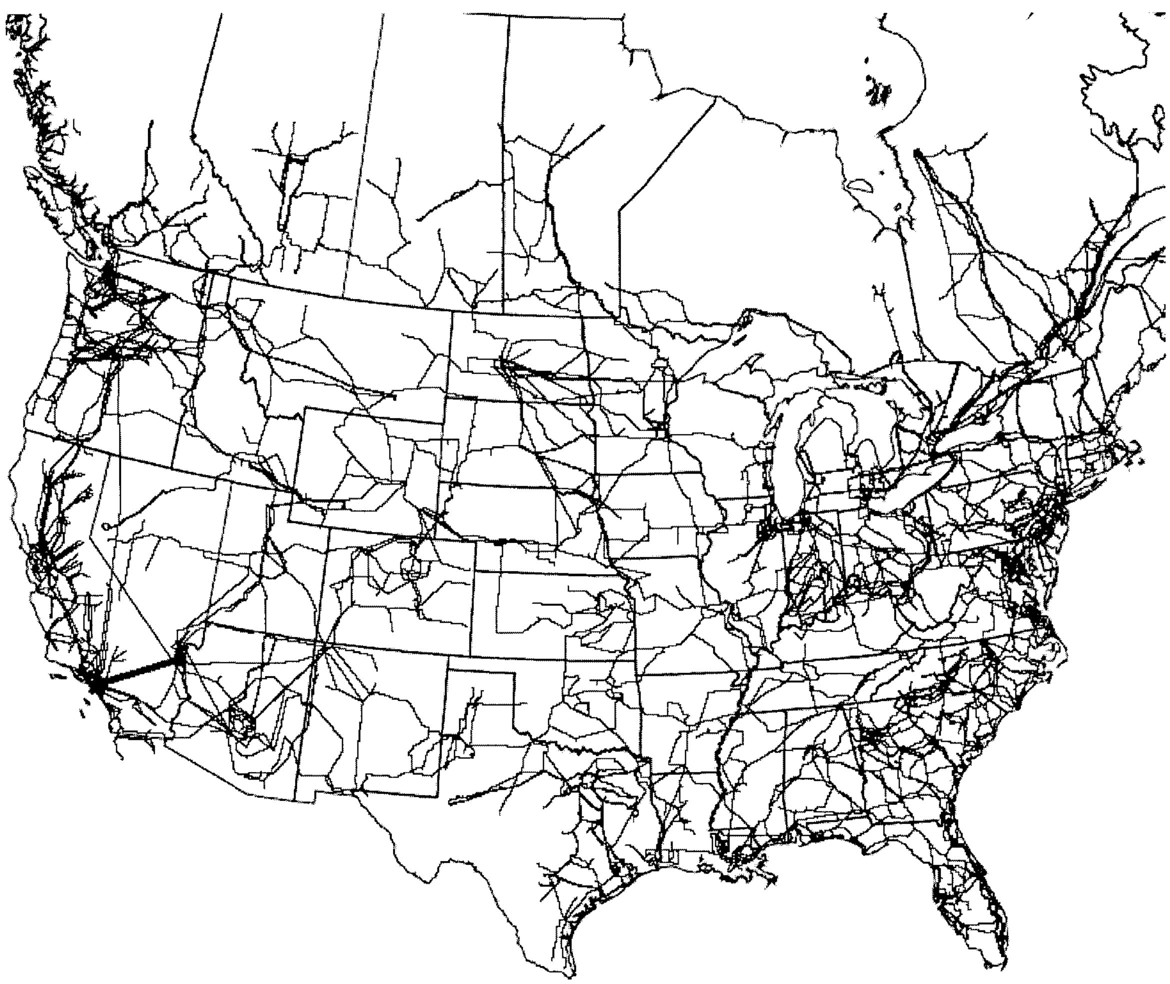


Figure 5.16 – High voltage transmission system: USA and Canada

Most transmission systems use overhead alternating current (AC) lines. However, some overhead direct current (DC) transmission systems and underground cables exist as well. This bulk power system makes it possible for utilities to engage in wholesale electric power trade. In other words, utilities have the option to purchase electricity from another region in place of generating the power themselves, if it is economic to do so and transmission transfer capability is available.

The transfer capability is defined as the ability of a transmission line to reliably transfer electric power in an interconnected network. In contrast with transmission capacity, which usually refers to a specific limit or rating of a particular line, transfer capability is a function of the physical relationship of that line with the other elements of the network. There are three types of constraints that limit the power transfer capability of the transmission system: thermal limits, voltage constraints, and system operating constraints (stability limits). The transfer capability is directional in nature, meaning that the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

The electric industry has used standard terms, techniques, and methodologies to define and calculate meaningful measures of the transmission transfer capability of the interconnected transmission networks. These terms include First Contingency Incremental Transfer Capability (FCITC), First Contingency Total Transfer Capability (FCTTC) or simply Total Transfer Capability (TTC), Available Transfer Capability (ATC), Recallable ATC (RATC), Non-recallable ATC (NATC), Transmission Reliability Margin (TRM), and Capacity Benefit Margin (CBM) [137], [138]. The determination of these values depends upon several assumptions and projections of system conditions.

Government agencies, namely FERC and EIA, collect transmission related data on survey forms, such as FERC Form 715, "Annual Transmission Planning and Evaluation Report," and the EIA Form 412, "Annual Electric Industry Financial Report." However, data collected through the FERC Form 715 is not publicly available and EIA Form 412 only collects rated capacity of transmission lines, expressed in megavoltamperes (MVA). In addition, ISOs and Regional Reliability Councils typically collect data that characterize transmission transfer capabilities, but the ways in which individual organizations define, collect, format, and make the data available to the public vary greatly from organization to organization. Furthermore, because of the variability of transfer levels and the complexity involved in their calculations, some electric systems report a range of possible transfer capabilities rather than a single transfer capability value.

In an attempt to foster and promote consistency in calculating and reporting electric system transfer capability, NERC prepares Reliability Assessments of the bulk electric power system, based on data they and others collect. These reports are produced twice a year and are available at NERC's website. Among other information, the Reliability Assessments present the normal base power transfers[1] and the FCITC for the bulk transmission systems between NERC regions and the subregions of SERC. The assumptions made in this study regarding transfer capabilities between these regions and subregions are based on the values reported by NERC on the 2001/2002 Winter Assessment [139] and 2002 Summer Assessment [140]. First, TTC are calculated as the net of the normal base power transfer plus FCITC available on the reports. Secondly, the averages of the Winter 2001/2002 and Summer 2002 TTC are computed. The values obtained through this procedure are assumed to be reasonable indicators of network performance and total transmission transfer capability between these model regions.

The transmission transfer capabilities within WECC and NPCC are not available on the NERC's Reliability Assessment reports. However, the Reliability Subcommittee of WECC prepares annual reports called Adequacy of Supply Assessments that contain information referred to as path ratings. Path ratings are the maximum path transfer capabilities based on WECC path rating methodology, which is similar to the TTC method used by NERC. The transfer capabilities between the subregions of the Western Interconnection are hence gathered from the 2002 Adequacy of Supply Assessment report [141]. On the other hand, NPCC publishes TTC and ATC values on their dedicated web site called TTC-ATC web site [142]. These TTC values are used to represent the transmission transfer capabilities between ISONE and NYISO, which are the two national subregions of NPCC.

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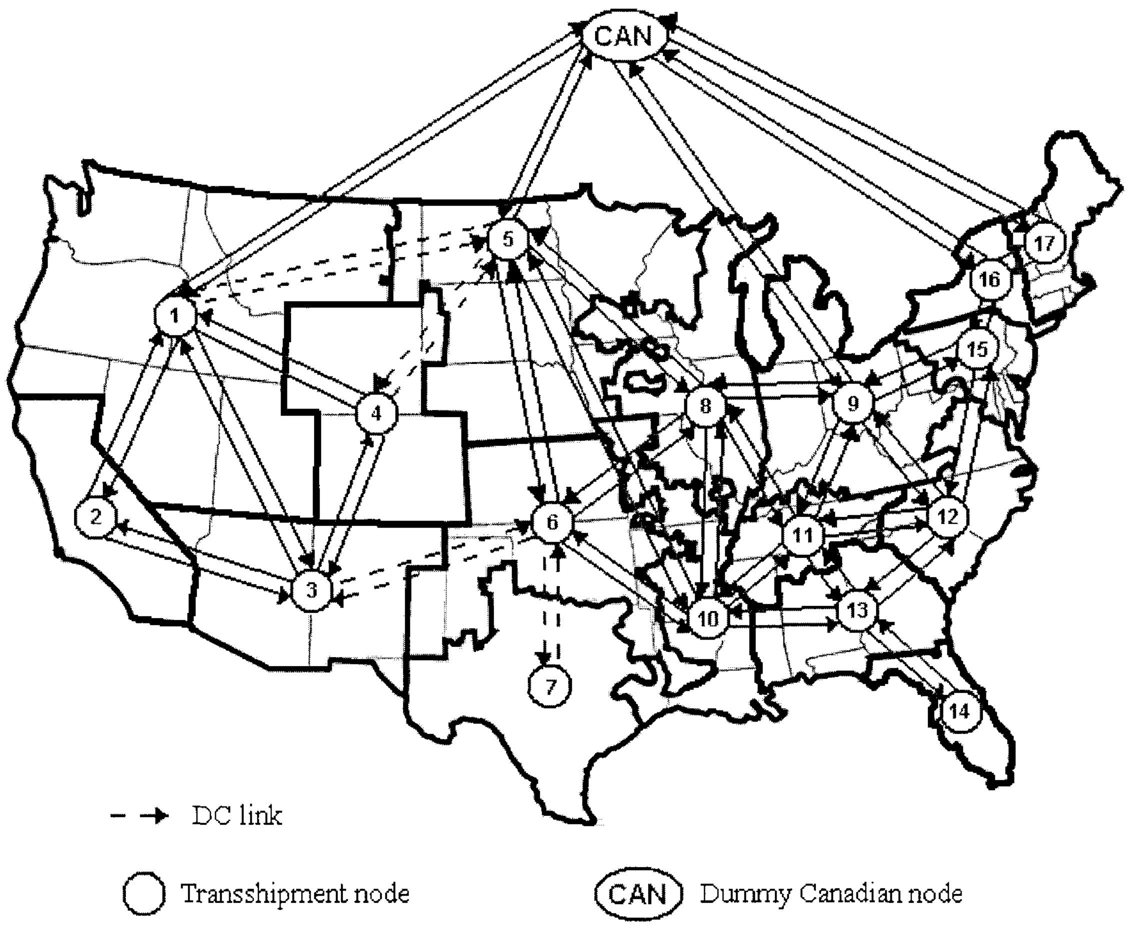
[1] Normal base power transfers: Electric power transfers that are considered by the electric systems to be representative of the base system conditions being analyzed, and which are agreed upon by the parties involved. In general, normal base power transfers refer to scheduled transfers only and other transfers, such as emergency or economy transfers, are usually excluded.

Figure 5.17 shows the transshipment nodes that represent the electricity model regions (hereafter called demand regions). The arcs between the transshipment nodes represent interregional transmission paths composed of one or more parallel tie lines connecting adjacent control areas in interconnected neighboring regions. In accordance with what is described in the next section, a dummy Canadian node and associated arcs are also included in Figure 5.17 to represent the power transactions with Canada.



1 - Northwest Power Pool Area (NWPP)
2 - California Power Area (CPA)
3 - Arizona–New Mexico–Southern Nevada Power Area (AZNMSNV)
4 - Rocky Mountain Power Area (RMPA)
5 - Mid-Continent Area Power Pool U.S. (MAPP)
6 - Southwest Power Pool (SPP)
7 - Electric Reliability Council of Texas (ERCOT)
8 - Mid-America Interconnected Network (MAIN)
9 - East Central Area Reliability (ECAR)
10 - Entergy Electric System (EES)
11 - Tennessee Valley Authority (TVA)
12 - Virginia-Carolinas (VACAR)
13 - Southern Company (SOCO)
14 - Florida Reliability Coordinating Council (FRCC)
15 - Mid-Atlantic Area Council (MAAC)
16 - New York ISO (NYISO)
17 - ISO New England (ISONE)

Figure 5.17 – Electric power transmission model

Table 5.12 summarizes the interregional transmission capabilities between the electricity model regions, i.e., the assumed capacities or upper bounds on the electricity flowing along the arcs depicted in Figure 5.17.

Table 5.12 – Transmission capabilities between demand regions

From	To	TTC (MW)
NWPP	CPA	6820
	AZNMSNV	1140
	RMPA	3050
	MAPP	150
CPA	NWPP	5235
	AZNMSNV	9965
AZNMSNV	NWPP	1200
	CPA	9905
	RMPA	650
	SPP	420
RMPA	NWPP	2800
	AZNMSNV	650
	MAPP	310
MAPP	NWPP	200
	RMPA	310
	SPP	1979
	MAIN	2216
	EES	2020
SPP	AZNMSNV	420
	MAPP	1362
	ERCOT	793
	MAIN	2217
	EES	1640
ERCOT	SPP	793
MAIN	MAPP	1109
	SPP	1108
	ECAR	2898
	EES	2808
	TVA	1447
ECAR	MAIN	3953
	TVA	1599
	VACAR	2064
	MAAC	2343
EES	MAPP	1005
	SPP	736
	MAIN	1367
	TVA	381
	SOCO	2065
TVA	MAIN	2278
	ECAR	2176
	EES	3070
	VACAR	2564
	SOCO	2740
VACAR	ECAR	4036
	TVA	2986
	SOCO	3456
	MAAC	3850
SOCO	EES	2535
	TVA	1310
	VACAR	1019
	FRCC	3600
FRCC	SOCO	2300
MAAC	ECAR	3882
	VACAR	4150
	NYISO	2755
NYISO	MAAC	2408
	ISONE	1600
ISONE	NYISO	1600

The cost of transferring electric power from one region to another is assumed to be 2 mills per unit of electric energy transmitted (kWh), for each of the links. This postage stamp rate is derived from data published by EIA on the "Electric Power Annual 2002" [143] and corresponds to the transmission wheeling charge. Although transmission pricing may be a very complex issue, the model assumes a fixed charge because of the lack of data on this matter and its relative insignificance.

The multiplier or efficiency parameter of all interregional electric transmission arcs is set to 0.98. This loss factor represents the electric energy loss because of the transmission of electricity. Much of the loss is thermal in nature. The value of the multiplier is estimated from EIA Form 861, "Annual Electric Power Industry Report."

Finally, it is important to note that, because of the aggregation level chosen, intraregional flows are not represented and electricity flows within each demand region are assumed to be unconstrained.

5.3.3 International Trade

As seen before, the U.S. electric power system is interconnected with transmission grids in both Canada and Mexico. Historically, the United States has been a net importer of electricity, which is mainly driven by trades with Canada. In 2002, the U.S. imported 36.4 terawatthours (TWh) and exported 14.5 TWh of electricity, out of which 36.1 TWh and 13.0 TWh were respectively imported from and exported to Canada [143].

The Office of Fuels Programs, Fossil Energy, collects data from entities that engage in international trade through the survey Form FE-791R, "Annual Report of International Electric Export/Import Data." However, these data are not publicly available. Nonetheless, data characterizing monthly transactions between the U.S. and Canada are available from the National Energy Board (NEB) of Canada. NEB publishes monthly statistics that specify electricity imports and exports by exchange type (firm, interruptible, or inadvertent) and by transmission interconnection. Since the model does not explicitly include the Canadian power market, transactions with Canada are incorporated at a fixed level based on data gathered from NEB [144]. In this way Canadian generation is not a decision variable and plays no role in the optimal energy flow solution. Table 5.13 shows the assumptions on net electricity imports from Canada. These energy values are derived by summing the firm and interruptible Canadian sales and subtracting the Canadian purchases for all international tie lines that connect to each valid demand region. The transshipment nodes that have connections with Canada are: 1-NWPP, 5-MAPP, 9-ECAR, 16-NYISO, and 17-ISONE.

Table 5.13 – Monthly U.S. net imports from Canada

Importing region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Net imported electricity (GWh)											
NWPP	467.8	128.7	-683.7	-451.5	-781.2	-486.3	772.9	522.8	835.8	669.1	739.0	732.8
MAPP	312.3	202.2	154.3	297.4	464.0	722.2	870.6	807.6	617.0	325.4	-84.1	-204.0
ECAR	-121.8	-26.1	-24.8	-41.4	0	3.3	-25.7	-67.4	-116.6	-93.9	-145.0	-496.6
NYISO	1424.3	1310.9	1822.2	1667.7	782.4	1333.8	1609.0	1440.3	30.2	28.6	-341.0	-57.0
ISONE	494.8	424.5	508.2	436.2	405.6	396.2	478.7	473.8	447.4	516.9	477.8	454.9

The annual variation observed in the electricity trade with Canada is mainly driven by the seasonal variation in hydraulic conditions, as most Canadian electricity exports originate from hydro-based resources. Although there is substantial variation among Canadian provinces, hydro power is the dominant source of electricity generation in Canada and has accounted for 80%-85% of Canadian exports in recent years [145]. In particular, electricity generation in the provinces of British Columbia, Manitoba, and Quebec is predominantly hydro-based, and these correspond to main origins of imports into NWPP, MAPP, NYISO, and ISONE regions. On a seasonal basis, imports also tend to be higher in the third quarter, corresponding to the peak air conditioning loads. This is most noticeable in the NWPP and MAPP regions. In contrast with the other regions, ECAR is a net exporter of electricity to Canada, namely to the province of Ontario.

International trade with Canada is incorporated, but it is assumed that transactions with Mexico do not occur since there were no existing firm power transfer agreements between the U.S. and Mexico in 2002. Furthermore, there are no publicly available data characterizing the bulk power trade across the U.S.-Mexican border.

5.3.4 Electricity Generation

To keep model size and solution time within acceptable limits, the model utilizes equivalent power plant nodes to represent aggregations of actual individual coal and natural gas generating units within each demand region. Generating units with similar characteristics are clustered into equivalent power plants with a combined capacity and weighted average characteristics that are representative of all the units comprising the equivalent plant. Within each region, the equivalent power plant nodes are differentiated by fuel type and prime mover, according to the following categories: coal steam (CS), gas steam (GS), combined cycle (CC), and combustion turbine (CT). Combined cycle and combustion turbine units use natural gas. These categories correspond to the classification made by EIA for conventional technologies. Coal-fired power plants are further disaggregated by the type of installed SO_2 pollution control device, i.e., the flue gas desulfurization technology used, if any.

Table 5.14 lists the equivalent power plant nodes included in the model and their characteristics. These data are valid for the beginning of the simulation period. Electricity generation capacity additions are shown in Table 5.15, by month of initial commercial operation. The main sources of information to derive the assumptions presented in these tables are:

- EIA Form 767, "Steam-Electric Plant Operation and Design Report." This annual survey collects data on existing and planned steam-electric plants such as boiler identification, location, status, and air pollution abatement technologies used. The relationship between boilers and generators is also provided.

- EIA Form 860, "Annual Electric Generator Report." This survey form is completed for all electric generating plants with a nameplate rating of 1 MW or more. It contains generator level information such as nameplate, summer, and winter capacity, location, status, prime mover, primary energy source, and in-service year.

- Emissions & Generation Resource Integrated Database (eGRID) developed by EPA. eGRID is a database that provides information regarding emissions profile, generation resource mix, plant characteristics, plant ownership, location, boilers, and generators. The most recent version of eGRID contains annual data from 1996 to 2000.

Table 5.14 – Equivalent power plant nodes

Region	Plant type	FGD	Number of units	Capacity (MW)	Avg. heat rate (Btu/kWh)
NWPP	CS	none	10	1,660	10,367
		wet	13	7,090	10,175
		dry	3	1,854	10,500
	GS		8	705	10,760
	CT		54	1,312	11,251
	CC		35	2,908	9,003
CPA	CS	none	16	460	9,904
		wet	1	45	8,162
	GS		93	18,377	9,766
	CT		245	5,528	11,271
	CC		108	4,054	9,619
AZNMSNV	CS	none	2	416	10,332
		wet	24	8,559	10,334
		dry	2	720	9,001
	GS		32	2,526	10,555
	CT		45	2,470	13,467
	CC		43	2,669	9,817
RMPA	CS	none	25	2,779	10,492
		wet	14	5,464	10,308
		dry	9	1,849	10,648
	GS		11	226	11,770
	CT		65	1,256	12,198
	CC		29	1,316	8,960
MAPP	CS	none	108	12,949	10,600
		wet	19	4,658	10,858
		dry	5	2,261	10,638
	GS		36	676	10,969
	CT		237	3,186	13,644
	CC		10	394	10,488
SPP	CS	none	52	11,788	10,186
		wet	13	6,425	10,554
		dry	3	1,401	10,479
	GS		132	13,709	10,329
	CT		351	5,236	12,728
	CC		40	4,480	8,076
ERCOT	CS	none	12	6,742	10,156
		wet	15	8,277	10,625
	GS		159	29,415	10,283
	CT		112	3,886	12,249
	CC		121	13,317	8,034
MAIN	CS	none	129	26,713	10,255
		wet	8	982	10,447
		dry	4	226	10,744
	GS		28	3,108	10,206
	CT		283	11,610	12,157
	CC		13	1,511	8,117

Table 5.14 – (continued)

Region	Plant type	FGD	Number of units	Capacity (MW)	Avg. heat rate (Btu/kWh)
ECAR	CS	none	286	59,708	9,643
		wet	66	23,079	9,911
		dry	4	264	10,370
	GS		21	1,828	11,258
	CT		262	11,454	11,990
	CC		26	2,846	8,552
EES	CS	none	12	7,227	10,248
		wet	1	670	10,050
	GS		68	16,145	10,467
	CT		32	1,519	11,714
	CC		50	4,442	7,327
TVA	CS	none	51	8,994	9,954
		wet	9	6,125	9,875
	CT		83	5,200	11,962
VACAR	CS	none	106	19,162	9,651
		wet	12	4,752	9,760
		dry	9	849	10,222
	CT		90	7,345	11,991
	CC		37	3,429	9,401
SOCO	CS	none	63	23,106	9,686
		wet	5	974	10,612
	GS		21	1,058	10,587
	CT		88	6,964	11,953
	CC		31	2,751	7,825
FRCC	CS	none	10	3,190	9,587
		wet	17	6,799	9,822
	GS		29	3,346	10,437
	CT		117	4,630	13,181
	CC		73	8,700	8,586
MAAC	CS	none	79	15,229	9,643
		wet	10	3,962	9,463
		dry	7	1,416	9,487
	GS		15	3,266	10,050
	CT		103	5,443	13,506
	CC		81	6,045	8,917
NYISO	CS	none	37	2,905	10,236
		wet	4	1,031	9,226
		dry	1	44	9,784
	GS		18	6,541	9,856
	CT		104	2,142	13,991
	CC		79	3,948	8,784
ISONE	CS	none	16	2,643	9,738
		wet	2	272	9,885
	GS		2	698	9,784
	CT		28	1,799	11,848
	CC		53	4,654	8,529

Table 5.15 – Electricity generation capacity additions by month

In-service month	Region	Plant type	Number of units	Capacity (MW)
1	NWPP	CT	1	135
	CPA	GS	1	11
		CT	5	235
	AZNMSNV	CC	3	588
	FRCC	CT	3	474
		CC	5	728
	MAAC	CC	3	528
2	CPA	CT	1	38
	RMPA	CT	2	134
	MAPP	CT	3	55
	SPP	CC	7	952
	ERCOT	CC	3	682
3	RMPA	CT	21	147
	MAIN	CC	2	286
	ECAR	CT	3	870
	VACAR	CT	1	146
	FRCC	CT	4	596
	MAAC	CC	3	547
	ISONE	CC	2	455
4	CPA	CT	1	41
	MAPP	CT	1	50
	ERCOT	CC	3	614
	MAIN	CC	4	573
	ECAR	CT	2	160
		CC	3	550
	SOCO	CT	1	109
		CC	3	491
	FRCC	CT	1	165
		CC	3	451
	MAAC	CT	1	49
		CC	1	245
5	NWPP	CT	6	168
	CPA	CT	1	42
		CC	4	811
	AZNMSNV	CT	6	230
	RMPA	CT	2	134
	MAPP	CT	1	120
	ERCOT	CC	10	1,828
	MAIN	CT	9	492
		CC	2	286
	ECAR	CT	7	788
	EES	CT	8	600
	VACAR	CT	1	146
	SOCO	CT	9	733
		CC	4	858
	FRCC	CT	3	406
	MAAC	CT	4	584
		CC	3	560
	ISONE	CC	5	241
6	NWPP	CT	6	233
	CPA	CT	3	138
	AZNMSNV	CT	6	228
		CC	3	580
	RMPA	CT	1	60
	MAPP	CC	6	91
	SPP	CT	5	364
	ERCOT	CC	13	2,421
	MAIN	CT	30	2,020
	ECAR	CT	20	2,117
		CC	3	600
	EES	CT	8	624
		CC	4	821
	TVA	CT	4	312
		CC	3	469
	VACAR	CT	4	627
	SOCO	CT	5	685
		CC	12	1,923
	FRCC	CT	5	802
	MAAC	CC	3	528
	NYISO	CT	1	49
7	NWPP	CT	4	42
	CPA	CT	2	73
		CC	6	1,200
	AZNMSNV	CT	1	76
		CC	6	918
	MAPP	CT	1	11
	SPP	CT	2	100
		CC	3	560
	ERCOT	CC	3	443
	ECAR	CT	8	810
		CC	8	488
	EES	CT	6	458
		CC	14	1,502
	SOCO	CT	4	312
		CC	1	294
	MAAC	CC	1	182
	NYISO	CT	4	190
8	NWPP	CC	10	1,126
	CPA	CT	1	41
	RMPA	CT	1	60
	ERCOT	CC	3	494
	ECAR	CT	3	204
		CC	3	479
	EES	CC	9	1,357
9	AZNMSNV	CT	1	60
	SPP	CT	2	131
	MAIN	CT	1	117
		CC	3	466

Table 5.15 – (continued)

In-service month	Region	Plant type	Number of units	Capacity (MW)
9	EES	CT	1	75
	SOCO	CC	2	978
10	NWPP	CC	3	525
	CPA	CT	1	43
	AZNMSNV	CT	1	38
		CC	2	251
	RMPA	CC	1	45
	ERCOT	CC	3	400
	MAIN	CT	2	234
10	EES	CT	1	75
	FRCC	CC	1	112
	ISONE	CC	3	515
11	AZNMSNV	CT	1	151
	MAIN	CT	1	117
	ISONE	CT	1	225
12	ISONE	CT	1	222
		CC	1	175

Units with status codes "OS" (out of service) and "RE" (retired) in EIA Forms are excluded. Likewise, FGD with status codes "CN" (cancelled, previously reported as planned), "CO" (new unit under construction), "OS" (out of service), "PL" (planned), and "RE" (retired) are not considered. For each generating unit the associated demand region was derived based on information from NERC's 2002 Electricity Supply and Demand Database (ES&D). For units with no NERC subregion or even no region data available on the ES&D database, state and county location reported in EIA Form 860 was used to allocate the units to their respective regions.

Fossil steam electric units have boilers attached to generators that produce electricity. In general, each steam generator is attached to a single boiler and likewise each boiler is dedicated to a single generator, in a one-to-one link. However, there are cases where a generator is connected to more than one boiler and there are also boilers that serve more than one generator. In order to avoid any confusion, from now on the term unit refers to a boiler in case of a steam unit and a generator in the case of a non-steam unit, i.e., a combined cycle or a combustion turbine.

The capacity values shown on Table 5.14 and Table 5.15 are the summer net capacity as reported on EIA Form 860, i.e., the maximum steady hourly output which generators are expected to supply during the summer peak season, after accounting for station or auxiliary services. To account for planned maintenance and forced outages, the capacity values are scaled down by the availability factors presented in Table 5.16. The availability assumptions are based on data from the NERC's Generating Availability Data System (GADS).

Table 5.16 – Availability factors

Plant type	Availability (%)
CS	84.35
GS	84.35
CT	93.19
CC	87.51

Regarding the air pollution control devices for removing SO_2 from coal-fired power plant stacks, there are two FGD technologies represented in the model: wet and dry. In wet processes, alkaline scrubbing liquor is utilized to remove the SO_2 from the flue gas, and a wet slurry waste or by-product is produced. Wet scrubber technologies include limestone forced oxidation, limestone inhibited oxidation, lime, magnesium-enhanced lime, and seawater processes. These technologies are available to coal steam units that combust bituminous coal with 2.5% or higher sulfur by weight. In dry processes, a dry sorbent is injected or sprayed to react with and neutralize the pollutant, forming a dry waste material. Dry scrubber technologies include lime spray drying, duct sorbent injection, furnace sorbent injection, and circulating fluidized bed. These technologies are available to coal steam units that combust bituminous, subbituminous, and lignite coal with less than 2.5% sulfur by weight. The classification into wet and dry scrubbers is a result of a comprehensive survey of FGD technologies and a detailed engineering cost and performance estimates for the different SO_2 controls. The results of this evaluation are described in EPA reports and other publications [146], [147]. The implications of Title IV of the CAAA in the decision-making process associated with generation dispatch and detailed information regarding the performance assumptions for each type of FGD represented in the model are discussed later in this chapter, in section 5.4.

The heat rate is a measure of a generating unit thermal efficiency, expressed in Btu per kWh. Although the EIA Form 860 collects data regarding heat rates, these data are only publicly available on reports prior to 1996. For more recent years, heat rate information has been withheld from the publicly available data, for confidentiality reasons. To the extent possible, the heat rate values reported in 1995 are used and assumed unchanged over time. Units that came online since then are allocated default heat rate values. The weighted average heat rates are then computed for each equivalent power plant node. If more detailed information were available, i.e., if instead of a constant heat rate value there were data publicly available regarding the input-output characteristics of the units, the modeling techniques described in section 3.4.6 could be applied. However, due to the proprietary feature of these data, even a single heat rate value is difficult to obtain, as indicated herein.

The variable operations and maintenance (O&M) costs associated with the generation of electricity, excluding fuel costs, are neglected. This is justified by data availability restrictions and also by the fact that the non-fuel O&M costs are small (ranging from 0.1 mills per kWh for combustion turbines to 3.38 mills per kWh for conventional pulverized coal units, already including SO_2 scrubber costs [148]). Therefore, dispatching decisions are assumed not to be significantly affected if these costs were taken into account. Fixed O&M costs are also excluded, because they represent the expenses incurred independently of the electricity generated. As a result, they do not affect the solution of the optimization problem, in terms of the energy flows of the integrated energy network.

Electricity generation from resources other than coal and natural gas are given exogenously. These include electricity generated from regulated utilities, independent power producers (IPP), and combined heat and power (CHP) plants. The different energy technologies can be categorized into oil (distillate fuel oil, residual fuel oil, jet fuel, kerosene, petroleum coke, and waste oil), nuclear, hydro (conventional hydroelectric power and hydroelectric pumped storage facility production minus energy used for pumping), biomass (wood, back liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass), wind, solar (solar thermal and photovoltaic energy), and geothermal. Only electricity generation that is available for sale to the grid is considered. For each of the demand regions, the net summer generating capacity of these technologies is presented in Table 5.17. These data were mainly derived from EIA Form 860, "Annual Electric Generator Report."

Table 5.17 also presents monthly generation factors used to represent the generation profile. When multiplied by the net summer capacity, these factors yield the hourly average generation output level for the correspondent month and power plant. Due to their low operation and maintenance costs, nuclear units are baseload power plants, i.e., they are run up to their availability. Therefore, the generation factors for nuclear power plants are always very high, sometime even greater than 100%, which represents a generation output above the net summer capacity level. Both scheduled maintenances and forced outages are taken into account in the generation factors. For certain types of units, such as hydro, wind, and solar technologies, the generation factors are mainly dictated by the seasonal and locational variations of the resources on which they rely. The monthly generation factor assumptions are derived from EIA Form 906, "Power Plant Report." This survey form collects, among other data, monthly plant-level generation from utility and non-utility power plants.

Table 5.17 – Non-coal and non-natural gas generation profiles

Region	Plant type	Capacity (MW)	Monthly generation factors (percentage)											
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NWPP	Oil	126	81	54	78	98	54	57	59	34	16	36	41	61
	Nuclear	1,108	102	57	101	97	98	67	84	98	92	101	98	102
	Hydro	35,991	43	38	35	44	49	59	52	39	30	31	34	36
	Biomass	500	60	45	54	49	48	53	58	61	60	66	58	63
	Wind	407	28	14	32	23	19	21	23	19	19	16	21	27
	Geothermal	160	102	90	96	89	93	80	112	84	88	93	90	98
CPA	Oil	790	23	18	25	23	24	26	32	29	28	26	26	23
	Nuclear	4,324	101	89	100	97	68	69	98	99	98	92	67	89
	Hydro	14,001	23	18	23	28	34	33	32	29	23	18	17	20
	Biomass	769	83	70	78	68	71	84	88	80	81	80	74	79
	Wind	1,531	12	13	23	36	42	49	39	42	26	25	14	13
	Solar	390	4	8	15	16	20	33	29	26	18	11	10	1
	Geothermal	1,950	79	70	77	69	76	72	77	77	75	77	74	77
AZNM SNV	Oil	90	16	13	15	14	12	12	12	11	13	12	13	13
	Nuclear	3,733	102	92	84	78	102	98	101	101	94	68	90	101
	Hydro	4,040	27	26	33	32	33	33	35	33	22	19	20	22
	Biomass	10	88	69	85	59	74	57	57	55	59	70	65	11
RMPA	Oil	182	1	3	4	2	0	2	2	1	1	1	2	1
	Hydro	1,468	10	8	11	13	18	21	21	18	9	4	6	5
	Biomass	61	33	43	45	46	48	39	29	31	31	49	0	21
	Wind	178	44	40	35	40	34	30	29	34	33	37	43	46
MAPP	Oil	3,001	3	3	3	2	2	3	4	3	3	3	3	3
	Nuclear	3,445	95	78	97	97	77	94	98	94	91	101	89	98
	Hydro	3,056	25	22	29	36	36	46	46	48	43	38	35	28
	Biomass	219	64	52	63	60	65	59	68	70	62	60	72	68
	Wind	655	39	44	30	41	36	32	17	22	27	29	33	39
SPP	Oil	1,342	8	8	15	6	3	1	3	7	4	5	3	6
	Nuclear	1,170	102	92	70	5	72	98	100	100	97	102	99	102
	Hydro	2,772	17	32	28	39	37	42	32	23	17	15	10	10
	Biomass	279	59	69	71	78	31	58	67	57	59	52	30	65
	Wind	192	37	44	49	49	49	47	32	38	35	30	35	34

Table 5.17 – (continued)

Region	Plant type	Capacity (MW)	Monthly generation factors (percentage) Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ERCOT	Oil	430	3	23	28	5	2	3	2	4	4	5	5	8
	Nuclear	4,737	101	91	99	74	94	91	97	99	94	51	46	73
	Hydro	536	11	9	12	12	20	19	37	19	14	10	7	10
	Biomass	74	10	60	77	69	77	71	79	82	73	76	75	70
	Wind	1,005	37	23	28	28	31	31	27	30	19	21	20	24
MAIN	Oil	1,929	8	7	6	6	6	4	9	9	8	6	3	3
	Nuclear	13,965	89	78	91	80	82	88	96	98	90	82	85	99
	Hydro	1,061	28	29	29	34	51	48	31	29	28	34	28	24
	Biomass	265	56	53	62	62	62	61	73	69	65	57	54	64
	Wind	6	109	131	108	97	79	49	41	44	64	72	77	114
ECAR	Oil	2,819	19	22	24	29	23	18	26	26	22	17	12	19
	Nuclear	7,690	86	64	74	85	71	71	85	87	66	85	83	87
	Hydro	3,410	9	8	10	11	11	8	7	3	4	8	11	12
	Biomass	428	77	66	91	78	67	81	81	91	75	91	75	70
EES	Oil	106	35	26	42	35	27	19	23	19	34	73	25	76
	Nuclear	5,078	102	92	95	74	94	96	100	101	80	82	93	102
	Hydro	343	41	56	53	69	51	59	36	25	16	23	28	38
	Biomass	247	98	82	79	88	78	65	73	80	104	102	53	59
TVA	Oil	103	44	32	78	27	36	48	37	16	23	32	22	37
	Nuclear	6,680	86	75	68	62	67	81	79	82	79	78	82	81
	Hydro	5,994	29	32	33	30	33	15	19	22	22	23	35	44
	Biomass	194	26	17	23	23	25	20	21	22	21	31	44	44
	Wind	2	34	25	34	27	28	9	7	9	13	15	27	32
VACAR	Oil	4,201	14	11	11	13	6	18	24	20	5	3	8	14
	Nuclear	14,690	101	90	85	84	90	97	100	99	87	86	85	97
	Hydro	8,979	5	4	4	3	2	0	0	2	2	5	8	13
	Biomass	851	47	47	51	53	53	50	60	54	62	47	38	56
SOCO	Oil	1,562	27	13	20	21	23	19	22	19	10	14	16	12
	Nuclear	5,698	97	90	79	72	100	97	100	100	88	65	79	89
	Hydro	4,307	21	19	18	18	18	7	7	6	9	12	29	37
	Biomass	905	59	42	45	110	40	115	53	106	37	45	22	37
FRCC	Oil	10,513	25	19	38	41	46	36	37	35	48	46	25	25
	Nuclear	3,906	103	93	98	94	63	97	102	100	95	83	96	103
	Hydro	50	35	43	59	54	39	24	27	25	33	41	65	50
	Biomass	685	77	65	75	67	77	79	86	77	78	73	64	67
MAAC	Oil	8,563	3	4	8	7	3	11	20	15	5	7	3	12
	Nuclear	13,046	99	87	77	78	86	91	97	98	90	87	95	101
	Hydro	2,900	5	13	12	16	24	14	2	0	1	8	13	17
	Biomass	671	63	61	66	63	69	68	78	73	70	54	60	63
	Wind	24	50	30	40	31	27	16	15	12	16	23	38	26
NYISO	Oil	7,508	15	9	13	13	16	18	25	23	10	12	20	27
	Nuclear	5,047	100	90	83	77	98	94	98	97	93	80	63	83
	Hydro	5,386	50	50	58	54	57	54	49	44	41	43	51	53
	Biomass	317	64	53	62	64	66	73	75	72	71	70	78	75
	Wind	48	13	13	14	14	14	16	16	17	15	14	13	68
ISONE	Oil	7,949	9	15	16	10	12	9	18	18	16	18	11	19
	Nuclear	4,340	100	80	79	87	70	94	99	93	74	84	97	93
	Hydro	3,570	11	13	20	25	25	25	15	9	9	11	17	18
	Biomass	1,317	71	63	73	62	68	69	71	72	70	64	59	73

5.3.5 Electricity Demand

Electricity consumption is assumed to be perfectly inelastic, i.e., non-responsive to changes in prices. This assumption is justified largely for two reasons. First, electricity is perceived as an essential good, a necessity, to maintain and improve the quality of life. Second, in the operational time frame considered, electricity has either no or very few substitutes in consumption. In conformity with this assumption, fixed electricity demands are allocated to the nodes representing the various demand regions.

The main source of information for electricity demand is the FERC Form 714, "Annual Electric Control and Planning Area Report." This survey form collects, among other data, actual hourly demand for each hour of the year, in megawatts, from electric utility control areas in the United States. Other relevant sources of publicly available information to characterize electric load are the EIA Form 826, "Monthly Electric Utility Sales and Revenue Data," and the EIA Form 861, "Annual Electric Power Industry Report." EIA Form 826 collects monthly information from a statistical sample of utility and nonutility companies that sell or deliver electric power to end users. Data collected include monthly retail sales for end-use sectors, in megawatthours. EIA Form 861 is completed by all the relevant electric industry participants and collects annual data on retail sales, in megawatthours, and non-coincident summer and winter peak demands, in megawatt.

Besides the differences in the aggregation level of the information collected by these survey forms, the main distinction between the data gathered by FERC Form 714 and the data collected through EIA Form 826 and EIA Form 861 is that the former refers to the net energy for load while the data on the EIA forms both correspond to delivered sales. Net energy for sale is defined as the systems net generation, plus energy received from others, minus energy delivered to others through interchanges. It represents the electrical energy requirements, including distribution losses. Delivered sales, on the other hand, does not include distribution losses. Therefore, when data are derived from these EIA forms, a distribution loss factor must be considered. Based on historical data, the distribution loss factor is assumed to be 1.07, independently of location. When multiplied by the distribution loss factor, delivered sales yield the net energy requirements.

Table 5.18 summarizes the electricity consumption assumption, for each demand region. These monthly values are directly taken from NERC's 2002 ES&D database and originally derived from EIA Form 411, "Coordinated Bulk Power Supply Program Report." The requirements for performing a disaggregated hourly analysis are prohibitive in the context of the time and resources needed to develop such an approach, without necessarily affecting the modeling results appreciably. Nonetheless, for more detailed studies, e.g. weekly, data are derived from FERC Form 714. Generation from nuclear, oil, renewable, and other non-conventional technologies are determined exogenously as shown in Table 5.17 and the demand curves adjusted to incorporate their contribution to load.

Table 5.18 – Monthly net energy for load

Region	Net energy for load (GWh)											
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
NWPP	20,579	18,353	18,518	17,296	17,434	17,110	18,744	18,429	16,989	17,896	18,684	20,955
CPA	22,061	19,768	21,459	20,295	22,543	22,700	23,832	24,592	22,447	21,935	20,807	21,886
AZNMSNV	8,582	8,295	9,129	9,221	9,525	10,506	12,187	12,267	10,805	9,170	8,114	8,820
RMPA	4,782	4,437	4,571	4,324	4,490	4,691	5,187	5,247	4,384	4,532	4,776	5,000
MAPP	13,473	11,941	11,945	10,981	11,069	12,031	13,750	13,665	12,004	11,580	11,944	13,141
SPP	16,154	14,113	15,029	13,888	15,311	17,906	22,053	21,628	16,514	14,744	14,493	16,008
ERCOT	22,344	19,506	20,842	20,522	24,575	27,633	31,265	31,118	26,559	22,585	20,383	22,354
MAIN	23,500	21,574	21,577	20,343	20,717	23,082	26,172	25,771	22,550	21,464	21,469	23,465
ECAR	50,177	45,280	46,134	42,439	43,904	47,225	51,494	50,932	45,404	43,943	44,517	48,680
EES	11,496	10,021	10,777	10,368	11,873	12,769	14,227	14,611	12,357	10,959	10,415	11,522
TVA	15,183	13,173	13,320	11,752	12,844	13,728	15,274	15,130	13,142	12,570	12,565	14,592
VACAR	26,220	23,276	23,569	21,359	23,111	26,107	29,588	28,996	24,724	22,616	22,889	25,719
SOCO	18,931	16,893	16,911	16,224	18,933	21,815	24,248	24,080	20,480	17,583	16,995	18,544
FRCC	15,911	14,281	15,164	15,384	17,768	19,175	20,420	20,820	19,425	17,114	15,348	16,001
MAAC	24,499	22,398	22,323	19,881	20,542	23,185	25,772	25,636	21,916	20,789	21,044	23,699
NYISO	13,250	11,696	12,917	11,732	12,371	13,678	15,008	15,079	12,922	12,501	12,365	13,582
ISONE	11,804	10,456	10,820	9,502	9,501	10,322	11,088	11,362	9,902	9,831	10,008	11,597

All regions must satisfy minimum reliability requirements. In particular, they all must have adequate reserve margin, where reserve margin is defined as the difference between available and dependable resources and the system's peak demand, expressed as a percentage of the system's peak demand. Reserves must be available in case resources are unexpectedly unavailable at the time of peak demand and/or demand exceeds the forecasted values. Reserve margin targets are established by the regions and vary depending on the types of resources available. Table 5.19 presents the non-coincident peak hour demand (internal demand) for the summer and winter peak periods, for each demand region.

Table 5.19 – Available resources and seasonal peak demands

Region	Available resources (MW)	Summer peak demand (MW)	Winter peak demand (MW)	Apparent reserve margin (%)
NWPP	56,050	33,274	35,026	60.0
CPA	54,849	49,149	37,023	11.6
AZNMSNV	27,853	23,864	16,421	16.7
RMPA	15,254	9,279	8,495	64.4
MAPP	34,827	26,794	22,907	30.0
SPP	50,770	39,446	28,290	28.7
ERCOT	74,219	57,761	41,097	28.5
MAIN	65,033	53,748	40,771	21.0
ECAR	119,909	96,328	87,190	24.5
EES	41,139	25,392	21,065	62.0
TVA	34,073	27,729	26,048	22.9
VACAR	65,177	55,359	52,573	17.7
SOCO	52,730	45,783	33,190	15.2
FRCC	43,021	35,895	38,199	12.6
MAAC	63,458	52,569	43,110	20.7
NYISO	35,156	30,475	24,670	15.4
ISONE	27,938	24,200	21,485	15.4

The summer peak period comprises the months of June through September, and the winter peak period includes the months of January, February, and December. The regions are not expected to reach their seasonal peak demands simultaneously. These data are obtained from the appropriate NERC's winter and summer Reliability Assessment reports. Table 5.19

also shows the available resources and an apparent reserve margin. For each demand region, the available resources are calculated as the sum of the generation capacities presented in Table 5.14, Table 5.15, and Table 5.17. The reserve margin computed using these available resources is shown in the last column of Table 5.19 and it is called an apparent reserve margin, because not all of the available resources considered are dependable. This is particularly the case in the NWPP region, where the reserve margin showed is fictitiously big due to high level of hydro generation capacity available in this region. In order to obtain the correct operating reserve margin values, no capacity credit should be given to non-dependable generation capacity, such as run-of-river, possibly wind, and solar generation capacity. Nonetheless, the apparent reserve margin values computed are reasonable and serve to validate the assumptions regarding available generation capacity in each demand region.

5.4 AIR EMISSIONS

To achieve the SO_2 emissions restrictions outlined in the CAAA, utilities are free to choose from a wide array of options. Planning options include installing pollution control equipment on existing power plants and building new power plants with low emission rates. Operating options include switching to the use of lower sulfur fuels, reducing the utilization of the relatively high emission units while increasing the utilization of their low emission units, purchasing power from utilities in neighboring regions which have lower emissions, and purchasing additional allowances from others. Since the objective of this study is concerned with an operational time frame, the compliance strategies incorporated in the integrated energy system are limited to the operating options. Retrofitting units with scrubbers and building new power plants with low emission rates are not considered. Likewise, emissions banking is an intertemporal issue that needs to be evaluated in a multi-year planning horizon. Therefore, banking decisions are exogenously given. Depending on the banking activities considered, emissions can exceed the sum of allocated allowances by using allowances banked in a previous year or decreased by banking allowances for a subsequent year.

Operating decisions for reducing emissions are based on the medium-term operating (fuel and operations and maintenance) costs and allowance trading is represented in the model by imposing a national-level limit on emissions. The national limit on emissions is determined by summing the 2002 vintage unit-level emissions allowances allocated in the CAAA and adjusted to represent additions or withdrawals from the bank. Data regarding SO_2 allowances are publicly available from the EPA Allowance Tracking System (ATS), which is a system of automated databases used to keep track of allowance accounts, holdings, transactions, and representatives. In 2002, there was a total of 8,646 thousand allowances allocated to the units included in the model. This number is smaller than the eventual 8.95 million tons limit imposed by the CAAA, because there are units that were allocated allowances and are not included in the model, namely oil-fired generating plants.

Table 5.20 shows the distribution of 2002 vintage allowances allocated to the coal and natural gas power plants, by demand region. The actual number of allowances deducted from each of these regions, i.e., the actual emission levels, is also listed in Table 5.20. The total number of allowances deducted from these units' accounts for compliance with the program is greater than the number of 2002 vintage allowances allocated to them. The difference is the result of the net banking and trading activities with other allowance owners not included in the model.

The level of emissions produced depends on the fuel used, pollution control devices installed, and the amount of electricity generated. The sulfur content for each type of coal is presented in Table 5.1 and it is negligible for natural gas. Table 5.21 presents the emission control performance assumptions.

Table 5.20 – 2002 allowances allocated and allowances deducted

Region	2002 allowances allocated (thousands)	Allowances deducted (thousands)	Region	2002 allowances allocated (thousands)	Allowances deducted (thousands)
NWPP	216	126	EES	242	167
CPA	91	0	TVA	430	535
AZNMSNV	219	120	VACAR	557	775
RMPA	239	162	SOCO	716	899
MAPP	522	467	FRCC	314	259
SPP	499	427	MAAC	731	1,126
ERCOT	525	441	NYISO	162	180
MAIN	759	655	ISONE	112	89
ECAR	2,312	3,018	**TOTAL**	**8,646**	**9,446**

Table 5.21 – Scrubber assumptions

Scrubber type	% removal	Capacity penalty	Heat rate penalty
wet	95%	0.98	1.02
dry	90%	0.98	1.02

The sulfur removal percentage is a measure of the scrubber efficiency. Although scrubbers have been designed for a wide range of efficiencies, the values assumed and presented in Table 5.21 correspond to the median design efficiencies as reported in [149]. The capacity penalty captures the fact that the electricity required to operate the scrubber reduces the maximum capacity available for sale to the grid by 2%. The heat rate penalty captures the increase in fuel used due to the operation of the scrubber. These assumptions are derived from [147].

The O&M expenditures associated with the operation of scrubbers, which include the labor and supervision cost, the maintenance cost, the reagent cost (limestone, lime, magnesium oxide, alkaline fly ash, etc.), the waste disposal cost, the cost of the electric power consumed, and other costs specific to each technology, are excluded. Generally, these O&M expenditures are small (ranging from about 1.8 mills per kWh for wet FGD technologies to 2.2 mills per kWh for dry processes [147]), and decisions to operate these abatement technologies are not expected to be altered if these costs were considered. Detailed flue gas desulfurization O&M expenditures are reported on Schedule 7 of the EIA Form 767, "Steam-Electric Plant Operation and Design Report."

The SO_2 emitted from all affected sources is limited by the number of allowances allocated by the regulating authority (EPA). It is assumed that all sources comply with the provisions of the CAAA. In other words, it is assumed that at the end of the compliance period each source holds sufficient allowances to cover its emissions. This is valid given the extraordinarily high (perfect or nearly 100%) compliance observed since the beginning of the program [150], which is mainly driven by the stringent financial penalties established by Congress ($2,000 per ton, 1990 dollars adjusted annually for inflation) and an adequate enforcement of the legislation.

Since allowances can be traded without any geographic limitations, restrictions on SO_2 emissions are implemented as national constraints. Allowance trading is assumed to occur at a regional level, with the regions having a low cost of compliance allowed to sell excess allowances to the higher cost regions. Intra-region trade is not explicitly represented. Although empirical studies have shown that most of the allowance transferred actually occur within the same utility or with affiliated firms [151], [152], most of these transactions may be considered noncommercial exchanges, since they represent mere reallocations done for administrative and accounting purposes, intra-utility, or intra-holding company movements of allowances. Therefore, the regional aggregation level at which the electric energy subsystem is modeled is appropriate to represent arm's length transactions that occur between nonaffiliated companies.

The market for allowance trading is further assumed to subscribe to all assumptions of perfect competition. In other words, the model does not capture any market imperfections such as market power and transaction costs.

CHAPTER 6. DETAILED MODEL STRUCTURE

6.1 BACKGROUND

The integrated energy model is specified as a multiperiod generalized network flow problem, which selects the pattern of coal and natural gas supply to the power plants that minimizes the overall total production, transportation, and storage costs of these fossil fuels, subject to certain conditions. These conditions include requirements that demands for electricity are met, technical limits are satisfied, and SO_2 emissions limits are not exceeded.

This chapter builds up on the information described in chapter 4.1 (Generalized Network Flow Model) and chapter 5 (Modeling Assumptions) to provide a detailed mathematical description of the model, where the objective function and equations of the constraint coefficient matrix are fully expressed.

The decision variables, right-hand side values, coefficients, and indices utilized are described below.

Decision Variables

$CP_{c,tc}$ Quantity of coal produced by coal supply region c, during time tc (short tons).

$CT_{c,e,tc}$ Quantity of coal transported from coal supply region c to demand region e, during time tc (short tons).

$CG_{c,e,cg,tc}$ Quantity of coal from supply region c consumed by generator type cg in demand region e, during time tc (short tons).

$GP_{g,tg}$ Quantity of natural gas supplied from gas supply region g, during time tg (Mcf).

$GA_{i,tg}$ Quantity of natural gas imported from Canada through the crossing border node i, during time tg (Mcf).

$GT_{i,a,tg}$ Quantity of natural gas imported from Canada through the crossing border node i into transmission region a, during time tg (Mcf).

$GT_{a,b,tg}$ Quantity of natural gas transported from transmission region a to transmission region b, during time tg (Mcf).

$GI_{a,tg}$ Quantity of natural gas injected into storage facilities in transmission region a, during time tg (Mcf).

$GW_{a,tg}$ Quantity of natural gas withdrew from storage facilities in transmission region a, during time tg (Mcf).

$GS_{a,tg}$ Quantity of natural gas carried over in storage facilities in transmission region a, from time tg into the next time period (Mcf).

$GG_{a,e,gg,tg}$ Quantity of natural gas delivered from transmission region a to generator type gg in demand region e, during time tg (Mcf).

$EG_{cg,e,te}$ Quantity of electricity generated from generator type cg in demand region e, during time te (MWh).

$EG_{gg,e,te}$ Quantity of electricity generated from generator type gg in demand region e, during time te (MWh).

$ET_{e,f,te}$ Quantity of electricity transmitted from demand region e to demand region f, during time te (MWh).

Right-Hand Side Values

$GD_{a,tg}$ Quantity of natural gas consumed by all non-electric power end-user sectors in transmission region a, during time tg (Mcf).

$GM_{a,tg}$ Quantity of natural gas exported to Mexico from transmission region a, during time tg (Mcf).

$EA_{e,te}$ Quantity of electricity imported from Canada into demand region e, during time te (MWh).

$EN_{e,te}$ Quantity of electricity generated by non-coal and non-natural gas units in demand region e, during time te (MWh).

$ED_{e,te}$ Quantity of electricity consumed in demand region e, during time te (MWh).

$TCP_{c,tc}$ Productive capacity for coal supply region c, during time tc (short tons).

$TCT_{c,e,tc}$ Amount of coal contracted between coal supply region c and demand region e for the period tc (short tons).

$TGA_{i,tg}$ Natural gas imported capacity through the crossing border node i, during time tg (Mcf).

$TGP_{g,tg}$ Effective productive capacity for gas supply region g, during time tg (Mcf).

$TGT_{a,b,tc}$ Maximum amount of natural gas that can be transported from transmission region a to transmission region b, during time tg (Mcf).

$TGI_{a,tg}$ Injection capacity of the storage facilities in transmission region a, during time tg (Mcf).

$TGW_{a,tg}$ Withdrawal capacity of the storage facilities in transmission region a, during time tg (Mcf).

$TGS_{a,tg}$ Total capacity of natural gas storage facilities in transmission region a, at time tg (Mcf).

$CGS_{a,tg}$ Cushion gas required in the storage facilities of transmission region a, during time tg (Mcf).

$TEG_{cg,e,te}$ Maximum amount of electricity that can be generated from generator type cg in demand region e, during time te (MWh).

$TEG_{gg,e,te}$ Maximum amount of electricity that can be generated from generator type gg in demand region e, during time te (MWh).

$TET_{e,f,te}$ Maximum amount of electricity that can be transmitted from demand region e to demand region f, during time te (MWh).

$NSO2$ National SO_2 limit (tons).

Coefficients

$KCP_{c,tc}$ Minemouth price at coal supply region c, during time tc ($/short tons).

$KCT_{c,e,tc}$ Cost of transporting coal from coal supply region c to demand region e, during time tc ($/short tons).

$KGP_{g,tg}$ Wellhead price at gas supply region g, during time tg ($/Mcf).

$KGA_{i,tg}$ Price of the natural gas imported from Canada through the crossing border node i, during time tg ($/Mcf).

$KGT_{i,a,tg}$ Cost of transporting natural gas from crossing border node i to transmission region a, during time tg ($/Mcf).

$KGT_{a,b,tg}$ Cost of transporting natural gas from transmission region a to transmission region b, during time tg ($/Mcf).

$KGW_{a,tg}$	Natural gas storage fee in transmission region a, during time tg (\$/Mcf).
KET	Electricity transmission cost (\$/MWh).
HC_c	Heat value of the coal extracted from supply region c (MMBtu/ton).
HG	Heat value of natural gas (MMBtu/Mcf).
$HR_{cg,e}$	Heat rate of generator type cg in demand region e (MMBtu/MWh).
$HR_{gg,e}$	Heat rate of generator type gg in demand region e (MMBtu/MWh).
η_{cg}	Heat rate penalty factor for generator type cg.
c_{cg}	Capacity penalty factor for generator type cg.
ηgp_g	Natural gas extraction loss factor at supply region g.
ηgt	Natural gas transmission loss factor.
ηet	Electricity transmission loss factor.
$SO2_c$	Sulfur content of the coal extracted from supply region c (lbs/MMBtu).
α_{cg}	Removal efficiency of the pollution control equipment installed at the generator type cg.

Indices

c	Coal supply region ($c = 1,\ldots,11$).
g	Natural gas supply region ($g = 1,\ldots,14$).
a, b	Natural gas transmission region ($a, b = 1,\ldots,6$).
i	Natural gas crossing border node ($i = 1,\ldots,4$).
e, f	Demand region ($e, f = 1,\ldots,17$).
cg	Coal-fired generator type ($cg = 1,\ldots,3$).
gg	Gas-fired generator type ($gg = 1,\ldots,3$).
tc	Time period for the coal subsystem.
tg	Time period for the natural gas subsystem.
te	Time period for the electricity subsystem.

6.2 OBJECTIVE FUNCTION

The objective is to minimize the total overall operating costs of meeting electricity demand from coal and natural gas sources over a medium term horizon. Cost components in the objective function include production cost for coal and natural gas, import natural gas from Canada, transportation cost for coal and natural gas, storage costs for natural gas, and electric transmission costs.

The objective function, which is to be minimized, is expressed as follows:

$$\begin{aligned}
&\sum_{tc}\sum_{c} KCP_{c,tc}CP_{c,tc} + \sum_{tc}\sum_{c}\sum_{e} KCT_{c,e,tc}CT_{c,e,tc} + \sum_{tg}\sum_{g} KGP_{g,tg}GP_{g,tg} + \\
&+\sum_{tg}\sum_{i} KGA_{i,tg}GA_{i,tg} + \sum_{tg}\sum_{i}\sum_{a} KGT_{i,a,tg}GT_{i,a,tg} + \sum_{tg}\sum_{a}\sum_{b} KGT_{a,b,tg}GT_{a,b,tg} + \\
&+\sum_{tg}\sum_{a} KGW_{a,tg}GW_{a,tg} + \sum_{te}\sum_{e}\sum_{f} KET \times ET_{e,f,te}
\end{aligned} \tag{6}$$

6.3 DESCRIPTION OF CONSTRAINTS

6.3.1 Balancing Constraints at the Nodes

Constraint (7), below, balances the coal produced in each coal supply region against the coal transported out of that region.

For specific c and tc: $$CP_{c,tc} - \sum_{e} CT_{c,e,tc} = 0 \tag{7}$$

Constraint (8) ensures that the coal delivered to each demand region from each coal supply region is distributed among the different coal-fired units in that demand region.

For specific c, e, and tc: $$CT_{c,e,tc} - \sum_{cg} CG_{c,e,cg,tc} = 0 \tag{8}$$

Constraint (9) balances the natural gas at the crossing border nodes.

For specific i and tg: $$GA_{i,tg} - GT_{i,a,tg} = 0 \tag{9}$$

Constraint (10) balances the natural gas at the transshipment nodes. It is expressed as a generic constraint with all possible arc types flowing into and out of the node. The feasible natural gas supply regions are those that geographically overlap with the specific transmission region, as explained in section 5.2.2.

For specific a and tg:
$$\sum_{feasible\ g}\eta gp_g \cdot GP_{g,tg} + \eta gt \cdot GT_{i,a,tg} + \sum_b \eta gt \cdot GT_{b,a,tg} - \sum_b GT_{a,b,tg} + GW_{a,tg} - GI_{a,tg} - \sum_{gg}\sum_e GG_{a,e,gg,tg} = GD_{a,tg} + GM_{a,tg} \quad (10)$$

Constraint (11) balances the natural gas at the storage nodes.

For specific a and tg:
$$GS_{a,tg-1} + GI_{a,tg} - GW_{a,tg} - GS_{a,tg} = 0 \quad (11)$$

Constraints (12) and (13) perform the necessary unit conversions at the equivalent power plant nodes. Note that the multiplier of the incoming flow to the power plant nodes represents a composite of incremental heat rate and unit conversions (heat value of the fossil fuel). In addition, coal-fired units equipped with scrubbers have their respective heat rates penalized to capture the increase in coal used due to the operation of this abatement technology.

For specific e, cg and tc:
$$\sum_c HC_c \cdot CG_{c,e,cg,tc} /(\eta_{cg} HR_{cg,e}) - \sum_{te \in tc} EG_{cg,e,te} = 0 \quad (12)$$

For specific e, gg and tg:
$$\sum_a HG \cdot GG_{a,e,gg,tg} / HR_{gg,e} - \sum_{te \in tg} EG_{gg,e,te} = 0 \quad (13)$$

Constraint (14) ensures that the electricity demand is met.

For specific e and te:
$$\sum_{cg} EG_{cg,e,te} + \sum_{gg} EG_{gg,e,te} + \sum_f \eta et \cdot ET_{f,e,te} - {} - \sum_f ET_{e,f,te} = ED_{e,te} - EA_{e,te} - EN_{e,te} \quad (14)$$

6.3.2 Bound Constraints on the Flows

Constraint (15) limits the amount of coal produced from each coal supply region.

For specific c and tc:
$$CP_{c,tc} \leq TCP_{c,tc} \quad (15)$$

Constraint (16) ensures that the coal supply contracts are validated.

For specific c, e, and tc:
$$CT_{c,e,tc} \geq TCT_{c,e,tc} \quad (16)$$

Constraint (17) limits the amount of natural gas imported from Canada through each crossing border node.

For specific i and tg:
$$GA_{i,tg} \leq TGA_{i,tg} \quad (17)$$

Constraint (18) limits the amount of natural gas supplied from each gas supply region.

For specific g and tg: $$GP_{g,tg} \leq TGP_{g,tg} \quad (18)$$

Constraint (19) restricts the amount of natural gas transmitted between transmission regions.

For specific a, b, and tg: $$GT_{a,b,tg} \leq TGT_{a,b,tg} \quad (19)$$

Constraints (20), (21), and (22) limit the amount of natural gas injected, withdrew, and carried over into the next time period at storage facilities in each transmission region, respectively.

For specific a and tg: $$GI_{a,tg} \leq TGI_{a,tg} \quad (20)$$

For specific a and tg: $$GW_{a,tg} \leq TGW_{a,tg} \quad (21)$$

For specific a and tg: $$GS_{a,tg} \leq TGS_{a,tg} \quad (22)$$

Constraint (23) requires minimum volumes of natural gas (cushion gas) to remain in the storage facilities.

For specific a, and tg: $$GS_{a,tg} \geq CGT_{a,tg} \quad (23)$$

Constraints (24) and (25) limit the electricity generated from each generator type in each demand region. Note that the capacity of scrubbed plants is penalized to represent the electricity required to operate the scrubber.

For specific cg, e, and te: $$EG_{cg,e,te} \leq c_{cg} TEG_{cg,e,te} \quad (24)$$

For specific gg, e, and te: $$EG_{gg,e,te} \leq TEG_{gg,e,te} \quad (25)$$

Constraint (26) limits the electricity transmitted between demand regions.

For specific e, f, and te: $$ET_{e,f,te} \leq TET_{e,f,te} \quad (26)$$

6.3.3 Emissions Constraint

Constraint (27) limits the SO_2 emissions produced as a result of electricity generation. SO_2 emissions are obtained by multiplying the total consumption of each coal type (on a heat content basis, i.e., in MMBtu) by the associated emission factor (in lbs/MMBtu). The result is the uncontrolled mass of SO_2 emissions (in lbs or tons). If the generator has SO_2 controls, the applicable removal efficiency is applied to obtain the total SO_2 mass emissions after scrubbing. The right-hand side represents the system-wide emissions limit, on a tonnage basis. It is obtained by summing the allowances allocated to all plants included in the model and adjusted according to banking decisions. As explained before, restrictions on SO_2 emissions are implemented as national constraints, because allowances can be traded.

$$\sum_{tc}\sum_{e}\sum_{c}\sum_{cg}(1-\alpha_{cg})\cdot SO2_c \cdot HC_c \cdot CG_{c,e,cg,tc} / 2000 \leq NSO2 \tag{27}$$

6.4 STEP BY STEP PROCEDURE

The complete procedure for obtaining the solution of the optimization problem described above may be divided into three main tasks: data gathering, matrix generator, and optimization routine, as summarized in the flowchart of Figure 6.1.

The first step is to identify the relevant sources of information, e.g. FERC forms, EIA forms, EPA's ATS, etc. Once data have been collected and the gaps resolved, the next step is to create the data input files. These are delimited text files and include the "nodes.txt" and the "arcs.txt" files. The first is a list of all the nodes and associated supply/demand. The other is a list of all the arcs and related information, including origin node, destination node, lower bound on the flow, capacity, efficiency rate, and per unit cost. Both "nodes.txt" and "arcs.txt" characterize a single time step representation of the network. In addition to these two files, other input files are created with data pertained to time-variant parameters (e.g., "load*i*.txt" for each specific demand region *i*).

The second main task is to generate the node-arc incidence matrix (or, more generically, the constraint coefficient matrix) in MPS format[1]. If a multiperiod simulation is desired, the input files "nodes.txt" and "arcs.txt" are expanded according to the user specified time steps for each energy subsystem, and the time-variant parameters updated. Then, the MPS format data file is created. This entire task (including the expansion of the network and the generation of the MPS format data file) is implemented in MATLAB.

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[1] MPS format: The MPS (Mathematical Programming System) format is a column oriented format for describing linear programming problems. Essentially all commercial optimization codes accept this format, including CPLEX.

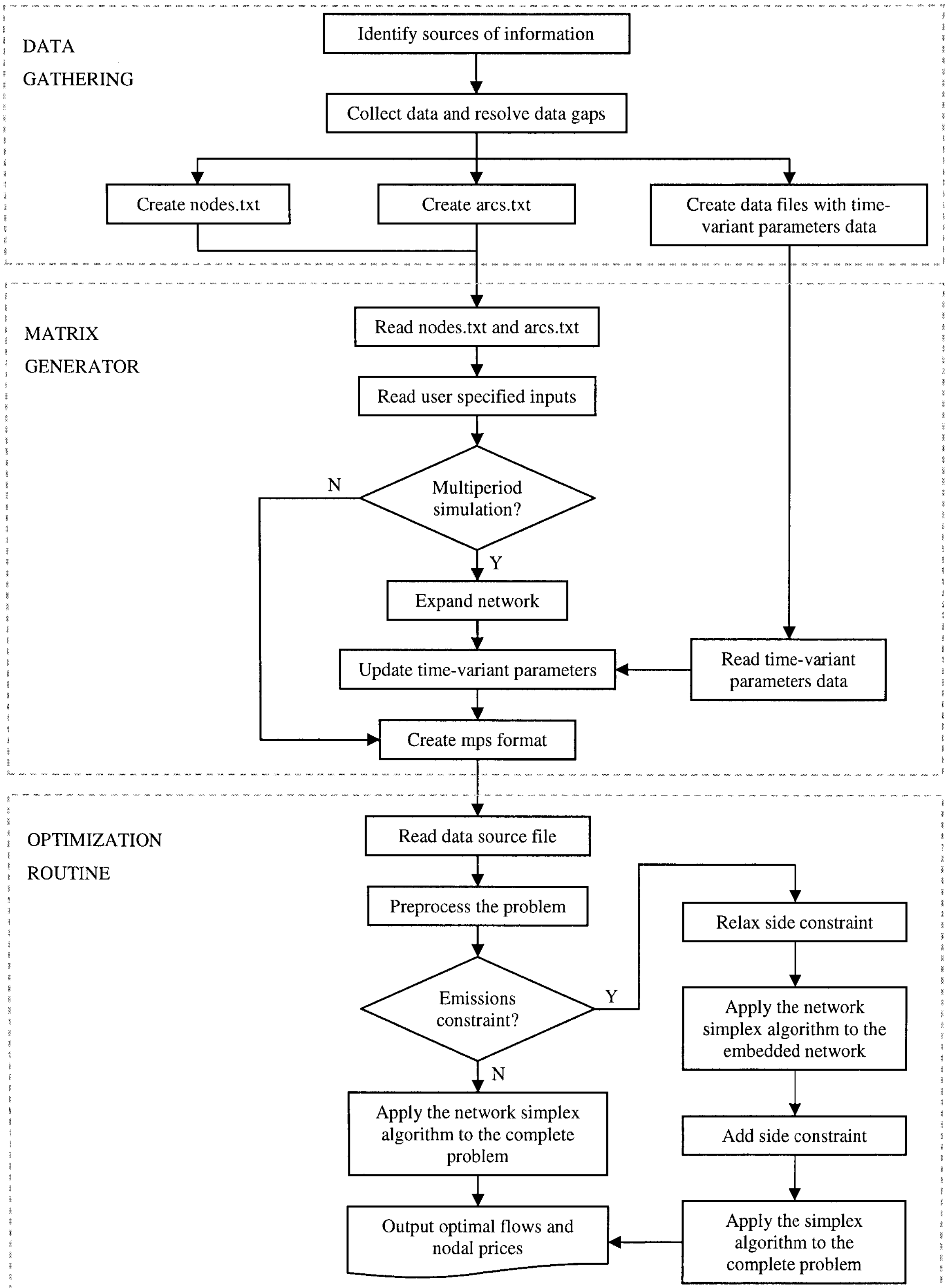

Figure 6.1 – Step by step procedure

The third and last main task, i.e., the optimization routine, is performed in CPLEX. After reading the MPS data file, CPLEX preprocesses the problem in an attempt to reduce its size, which is, in general, beneficial for the total solution speed. Opportunities to reduce the size of the problem arise through the simplification of constraints and elimination of redundancy. For example, nodes with indegree of 1 and outdegree of 1 (i.e., nodes with only one incoming arc and one outgoing arc) may be eliminated and the parameters of the equivalent arcs adjusted. Nonetheless, CPLEX reports the model's solution in terms of the original formulation, making the exact nature of any reductions immaterial.

After preprocessing the problem, the network optimizer routine is called to solve the problem. The problem need not be entirely in network form, as it is the case when the emissions constraint is included. In this case, CPLEX automatically relaxes the side constraint and solves the network portion using the network simplex algorithm. Then, CPLEX performs standard linear programming iterations on the full problem using the network solution to construct an advanced starting point. If no side constraints exist, CPLEX solves the entire problem directly using the network simplex algorithm.

When the optimization is complete, solution information is written to a standard solution file in text format. The solution file contains the value of the variables (the optimal flows) and the dual activities or nodal prices associated to the constraints. As explained elsewhere, the nodal prices provide the sensitivity of the objective value to a unit change in their respective constraints' right-hand side value.

6.5 VISUALIZATION OF THE RESULTS

The visualization capabilities of ArcView[1] 9.1 are used to display the networks and the simulation results on a map. Using this GIS software allows us to better understand the geographic context of the results and identify patterns.

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[1] ArcView: ArcView is a geographic information system (GIS) software program for visualizing, managing, creating, and analyzing geospatial data, developed by the Environmental Systems Research Institute (ESRI) of Redlands, California.

Firstly, the modeling assumptions defined in chapter 5 are converted into shapefiles, i.e., thematic layers and datasets with a geographical reference. Shapefiles are created directly by digitizing shapes using ArcView feature creation tools. Figure 6.2 through Figure 6.4 show the different layers that compose the integrated energy network map presented in Figure 6.5. For displaying purposes only, the three different coal steam technologies included in the model (without scrubbers, with wet scrubbers, and with dry scrubbers) are clustered into one coal-fired generator node in each region. Likewise, gas steam, combustion turbine, and combined cycle units are represented by a single gas-fired generator node in each region.

Simulation results are then converted into databases with the appropriate field structure, appended to the adequate shapefile attribute table, and displayed with graduated symbols, colors, charts, or any other of the available tools in ArcView, as shown in the chapter 7.

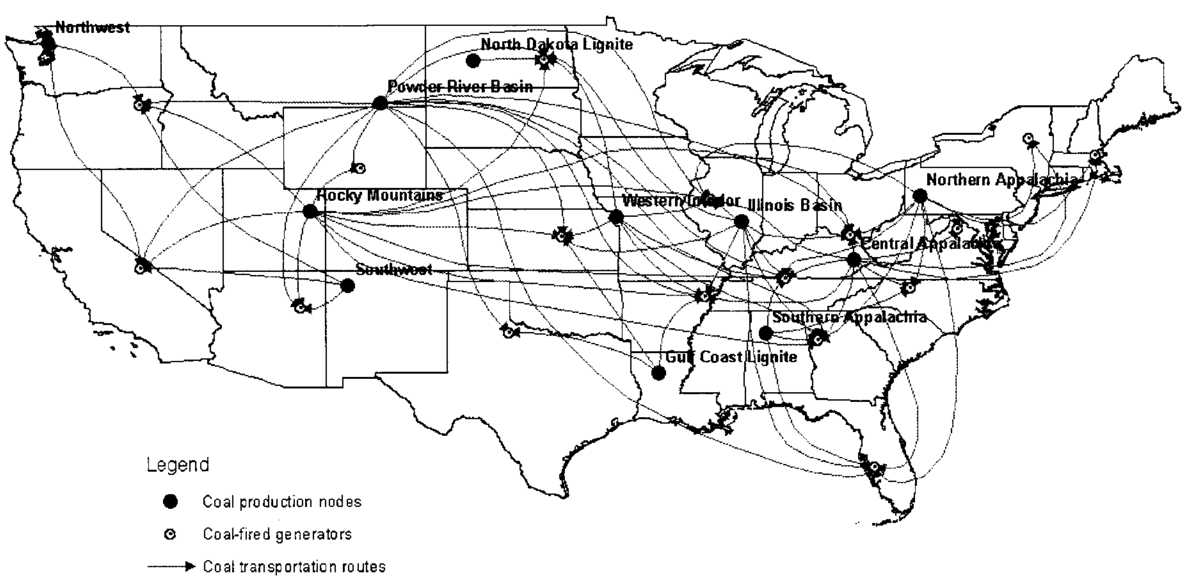

Figure 6.2 – Coal network layer

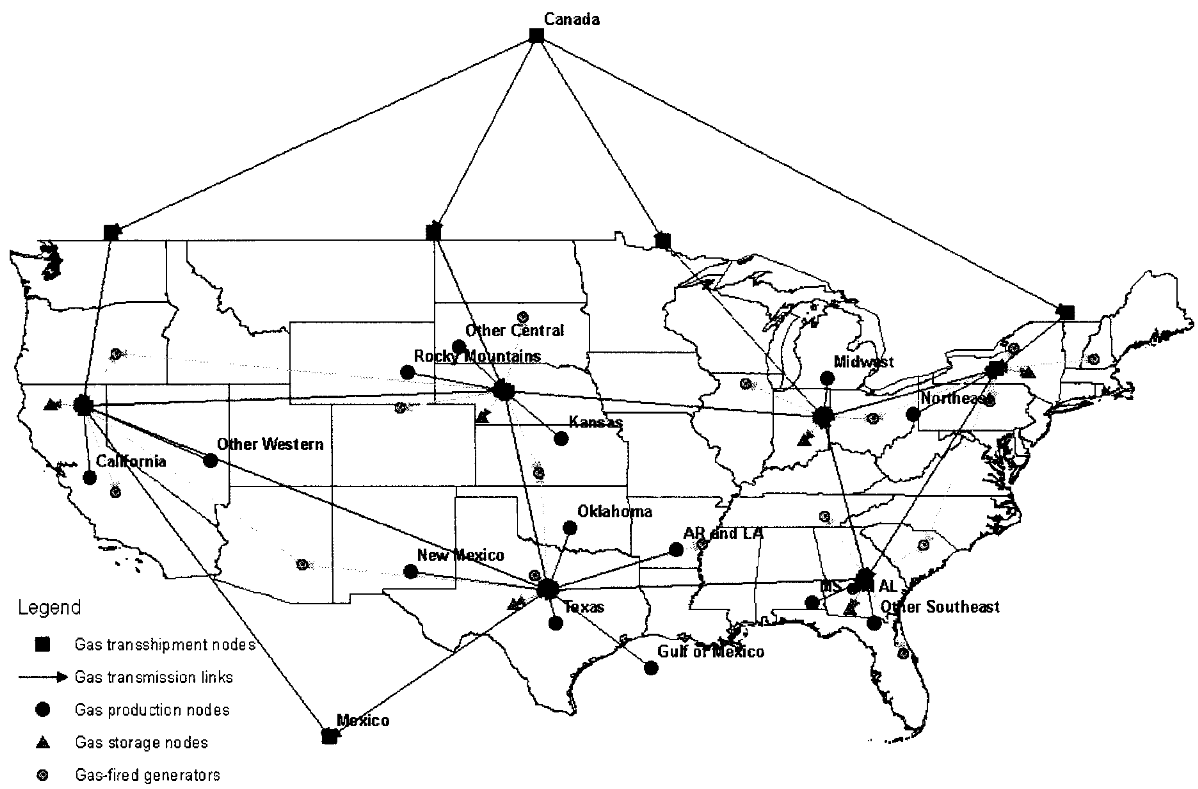

Figure 6.3 – Natural gas network layer

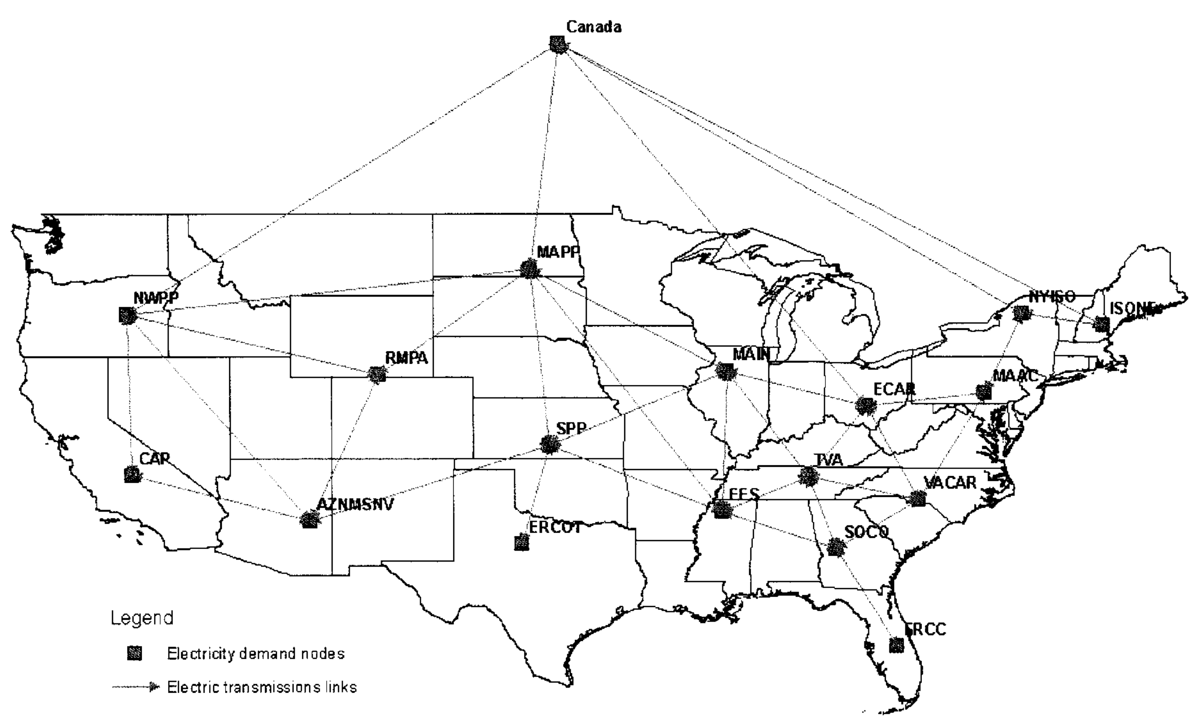

Figure 6.4 – Electricity network layer

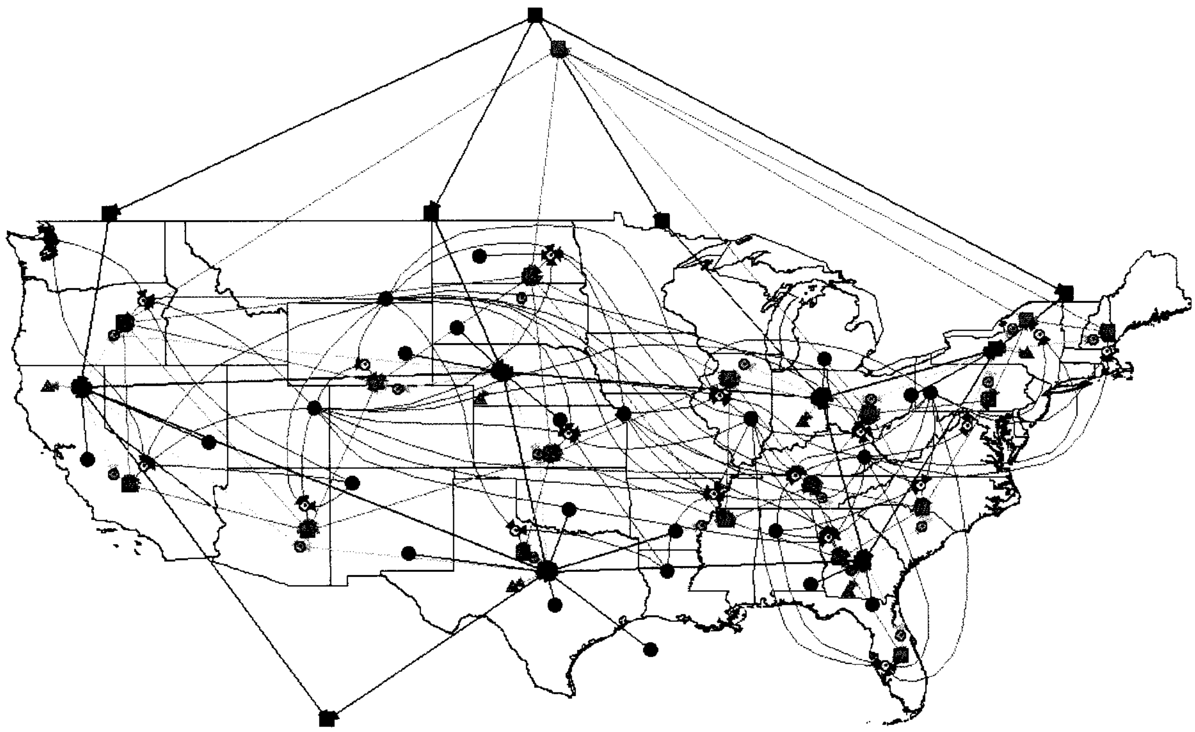

Figure 6.5 – Integrated energy network map

CHAPTER 7. STUDY RESULTS

7.1 VALIDATION

To check the accuracy of the model and in order to provide benchmark results that approximate the actual network flows, the reference case is designed with the actual configuration of generation and loads reported on a monthly basis for the year 2002. This is to say that the flows along the mid-stream part of the overall transportation model are forced to be the same as historical data indicates. Generation data are derived from EIA Form 906 and loads are obtained from NERC's ES&D database. On EIA Form 906, power plants are differentiated by fuel type used and prime mover. However, the distinction between coal steam units with and without scrubbers is not made. As a result, within each model region, the sum of the electricity generated from all modeled coal steam units (without scrubbers, with wet scrubber technologies, and with dry scrubber technologies) is fixed to the actual generation level reported on the survey form. The coal and natural gas flows are optimized to achieve the least cost solution that corresponds to the actual generation and load levels. This historical configuration is a feasible solution for the network flow model, resulting in the coal and natural gas consumption levels and SO_2 emissions shown in Table 7.1.

Table 7.1 – Results with fixed generation

Result	Model	Actual	Difference
Coal deliveries (million tons)	951	976	– 2.56 %
Natural gas deliveries (million Mcf)	5,125	5,398	– 5.06 %
SO_2 emissions (thousand tons)	8,583	9,446	– 9.14 %

The coal and natural gas deliveries to power plants approximate the actual values, with the errors being –2.56% and –5.06%, respectively. This provides an indication that the assumptions concerning the heat values for the different types of coal and natural gas and the generators' heat rates are adequate. SO_2 emissions are however 9.14% below the actual level, which results from optimizing the fuel network flows and not distinguishing between coal steam technologies with and without scrubbers. On one hand, the optimization of the coal flows is expected to overestimate the utilization of low-cost, low-sulfur coal with the associated underestimation of emissions. On the other hand, the most efficient coal-fired units, which are also likely to be the ones equipped with the most efficient scrubber technology, are used first, thus resulting in an overestimated utilization of scrubbers and again an underestimation of emissions.

To further approximate the true network flows, the amount of SO_2 emitted is constrained to be equal to the number of allowances actually deducted from generators' accounts to comply with environmental regulations. The coal and natural gas flows are again optimized to achieve the least cost solution that now corresponds to the actual generation, load, and emissions levels. The resulting coal and natural gas deliveries and allowance price are presented in Table 7.2.

Table 7.2 – Results with fixed generation and emissions

Result	Model	Actual	Difference
Coal deliveries (million tons)	953	976	– 2.35 %
Natural gas deliveries (million Mcf)	5,125	5,398	– 5.06 %
Allowance price ($)	98	130	– 24.61 %

The allowance price obtained from the model ($98 per allowance) is the nodal price or dual variable associated with the emissions constraint. This reflects the marginal cost of compliance, or the penalty level for emitting an additional ton of SO_2, given the modeling assumptions and under an optimized coal production and transportation pattern. Actual allowance prices for 2002 followed a downward trend, hovered in the $170 range early in 2002 and ending the year in the $130 range [150]. The discrepancy between the model result and observed allowance prices may be explained by the following reasons:

- Because coal flows are optimized to achieve the least cost solution that corresponds to the actual generation and emissions levels, the outcome is likely to be overestimating the utilization of low-priced coal, in $/MMBtu terms. It turns out that the least expensive types of coal also rank low on sulfur content, which would result in an underestimation of the allowance prices. In reality though, there may be infrastructure limitations in delivering cleaner and cheaper western coal to the east, which are not being captured by the model.

- The choice of installing scrubbers to meet the emissions cap and the associated large up-front capital costs that this compliance strategy represents are not included in the model. As power plants use banked allowances to comply with the stringent Phase II[1] requirements, banks are expected to continue to be depleted. Figure 7.1 shows the evolution of SO_2 emissions and allowance bank over time. This suggests that power plants are likely to be anticipating more expensive abatement efforts, including retrofitting units, for meeting compliance requirements in the future. The prediction of future expenditures on abatement technologies would be reflected in the allowance prices.

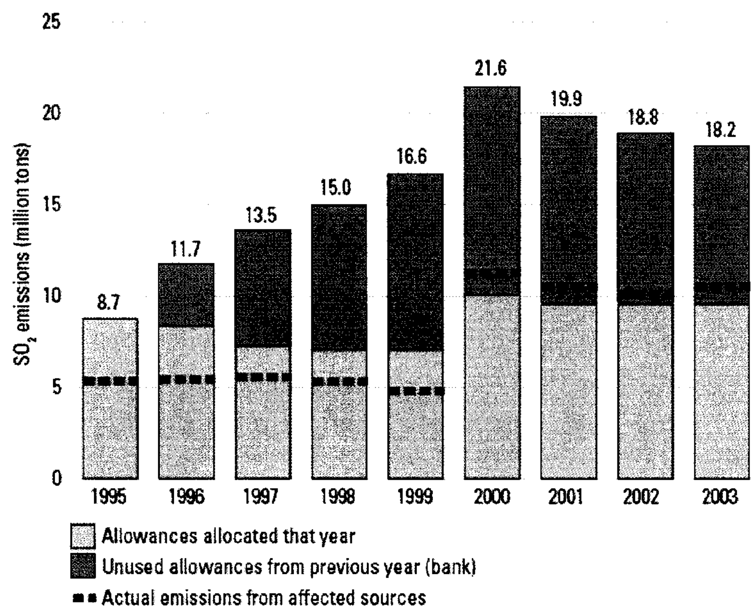

Figure 7.1 – SO2 emissions and the allowance bank, 1995 – 2003 (Source: EPA)

- While coal prices were not expected to change significantly, natural gas prices were predicted to increase, which would lead to coal-fired electricity generation increases and less opportunity for economical compliance from fuel switching, placing an upward pressure on allowance prices. In fact, in 2003 coal prices for

[1] Phase II of the CAAA, which began in 2000, increased the universe of affected units to include virtually all steam units with a nameplate capacity of 25 MW or larger. The cap established is based upon a more stringent rate than that allowed under Phase I.

power generation rose about 2%, whereas natural gas prices increased 51%. Figure 7.2 presents the evolution of fossil fuel costs for the electric power industry, from 1993 to 2004.

In summary, the market price of allowances is largely based on expectations of their future value, which are not recognized by the network flow model.

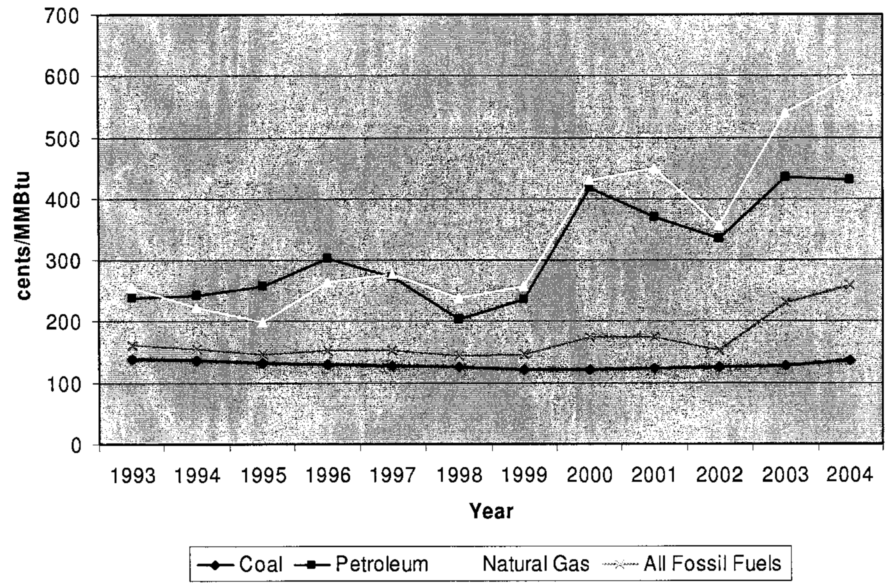

Figure 7.2 – Fuel costs for the electric power industry, 1993 – 2004 (Source: EIA)

This configuration with actual generation, load, and emissions and optimized coal and natural gas flows is denoted as the reference case. The reference case is used in the following section as a benchmark for comparison with the global optimal solutions with and without emissions constraint.

7.2 CASES CONSIDERED

This section shows the results of three case studies: (A) reference case, (B) optimal case without emissions constraint, and (C) optimal case with emissions constraint. All the cases were simulated with yearly data for the coal network and monthly data for the natural gas and electricity networks. In each case, the network flow model is composed of 1290 nodes and 3480 arcs. The results are obtained using the network optimizer routine of CPLEX 8.1 in a 2.8 GHz Pentium 4 processor with 1 GB of RAM. The computing time is less than

0.5 seconds for each case.

The reference case is designed with the actual configuration of generation, loads, electric power trade, and emissions, as described above. In case B, only the electricity demand is fixed. The coal, natural gas, and electricity flow patterns (including electricity generation and interregional trade) are endogenously determined to satisfy the same load at the overall minimum cost and without any limitations on SO_2 emissions. The specifications for this case are the same as those for the reference case, except that generation levels and emissions are not restricted to the actual values. Consequently, electric power trades are also endogenously determined. The energy flows are optimized over the entire geographical area considered (lower 48 states), yielding an efficient economic solution over all regions. In essence, this case gives an indication of the impacts of a centralized decision making process and perfect competition, showing optimal flow patterns and the opportunities to reduce aggregated costs, subject to system constraints, but ignoring the constraint on emissions. Case C builds on case B to show the effects of considering the SO_2 emissions limit. Case C, thus, provides the means to estimate the cost of compliance with the restrictions imposed by the CAAA.

7.3 ENERGY FLOWS

7.3.1 Summary Results

Summary results for the three analysis cases are presented in Table 7.3. As expected, coal deliveries and electricity generation from coal-fired power plants increase in cases B and C, when compared to the reference case A. Conversely, natural gas deliveries and electricity generation from gas-fired units decrease. In other words, the same levels of electricity generation are achieved using cheaper resources, which results in an overall cost reduction. In addition, net exchanges of electricity increase among the modeled regions.

Not so obvious are the small differences observed between case B and case C. When the emissions constraint is in place, the overall costs increase only slightly. Net electricity trade decreases, but the shares of electricity generated from coal and natural gas remain practically the same. While natural gas production and transportation patterns remain unchanged, the flows of coal are somewhat altered, with cleaner coal replacing dirtier coal and generating units equipped with scrubbers being more utilized. In this situation, the allowance price obtained is $359, which is above the market values observed for 2002, due to the heavy reliance on electricity generation from coal that the optimal solution represents.

Table 7.3 – Summary results

Result	Case A	Case B	Case C
Coal deliveries (million tons)	953	1,054	1,048
Natural gas deliveries (million Mcf)	5,125	3,615	3,615
Electricity generation from coal (thousand GWh)	1,910	2,117	2,116
Electricity generation from natural gas (thousand GWh)	607	414	414
Net electric power trade (thousand GWh)	205	382	367
Allowance price ($)	98	------	359
Total costs (billion $)	101.42	96.89	96.96

7.3.2 Coal Network

The annual coal production by coal supply node is shown in Figure 7.3, for the three cases analyzed. As predicted, Powder River Basin is the leading source of coal, producing about 40% of the total coal delivered to power plants. When electricity generation levels are not restricted to the actual values, i.e., when moving from the reference case to cases B and C, the national coal production increases. In case B, coal production is intensified in the Powder River Basin and in the Northern Appalachian regions. With the emissions constraint imposed in case C, the Northern Appalachian coal production decreases and is compensated by an increase in Central Appalachian coal. Although the heat value is about the same for the coal extracted from these two regions, Central Appalachian coal is more expensive, but has lower sulfur content.

The geographical distribution of the coal production is displayed in Figure 7.4. This figure also shows the aggregated coal flows from the coal production nodes to the demand nodes (aggregated coal-fired generators) obtained in case B. The width of the arcs is proportional to the flow, as identified in the legend. For clarity, the arcs with flow zero are not displayed. As it is shown, most of the coal flows into the Central and Midwestern parts of the country, where the majority of the coal-fired power plants are located.

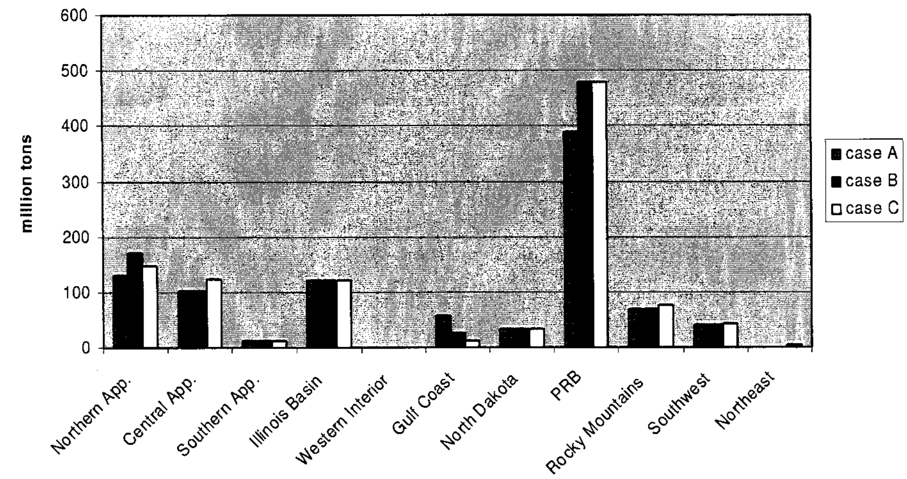

Figure 7.3 – Annual coal production

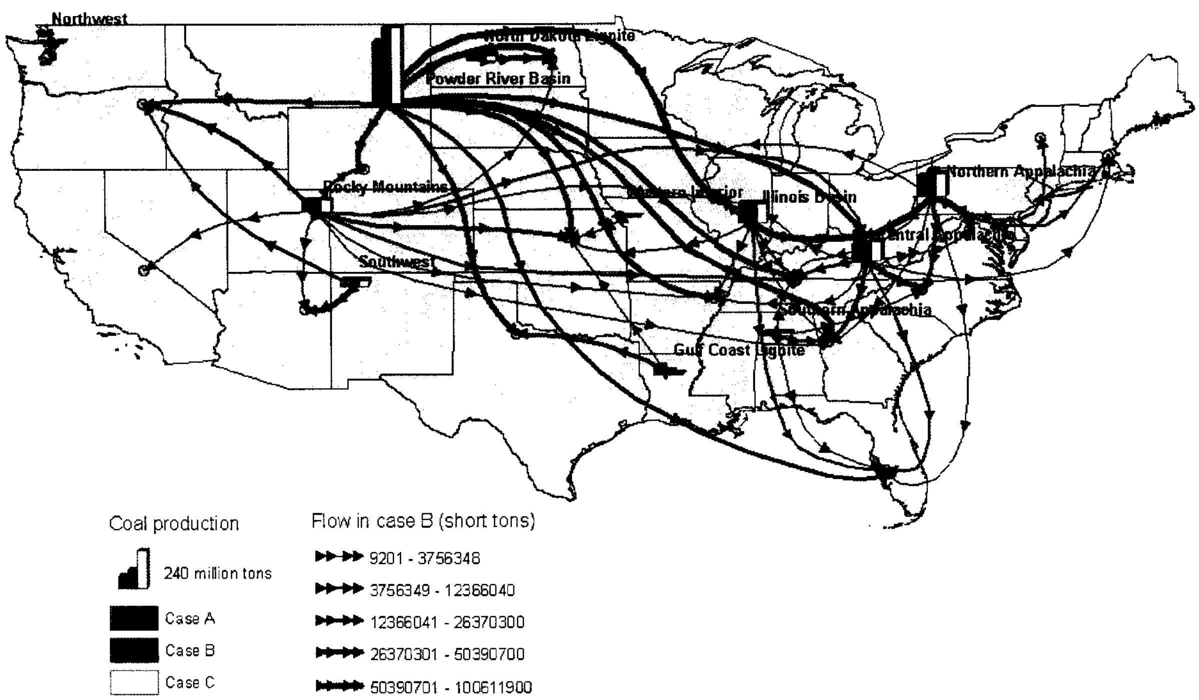

Figure 7.4 – Coal flows

As coal transportation capacity is assumed to be available to meet coal transportation requirements, the model is not suitable to identify possible congestions in these transportation links. However, coal deliveries to power plants are restricted by the coal productivity capacity, as explained in section 5.1. Table 7.4 lists the coal production nodes that are at full capacity. In all cases, the Illinois Basin and the North Dakota Lignite nodes are producing the maximum possible. This is mainly because of the proximity of these production regions to the major coal-fired units, which results in lower transportation costs and ultimately lower delivered prices. In the optimal solution cases, the Powder River Basin increases its production to the upper limit, given the characteristics of the coal extracted from this location (low minemouth price, average heat value, and low sulfur content). With the emissions constraint in place, all subbituminous western coal nodes increase their production (except the Powder River Basin, which is already at the maximum), leading the Rocky Mountains area to achieve the full production capacity.

Table 7.4 – Coal production nodes at full capacity

Production Node	Case A	Case B	Case C
Illinois Basin	×	×	×
Gulf Coast Lignite	×		
North Dakota Lignite	×	×	×
Powder River Basin		×	×
Rocky Mountains			×

7.3.3 Natural Gas Network

Figure 7.5 and Figure 7.6 show the natural gas production and imports from Canada, respectively, for all supply nodes. As expected, most of the national production of natural gas comes from the Gulf of Mexico and the areas around Texas and the Rocky Mountains. When the electricity generation levels are not restricted to the actual values, natural gas supply decreases. This is mainly realized through a reduction in the Texas and Gulf of Mexico production and in the Canadian imports into the Central and Western regions. It is interesting to note that the reductions do not occur in these supply nodes for being the most expensive ones, but rather as a result of an overall optimization that takes into account the coal and electricity generating resources available to fulfill the fixed geographical distribution and levels of demand. In addition, it should be recalled here that, in contrast with coal, natural gas supplies are not exclusively driven by the electric power consumption sector. In fact, the heating needs for industrial, residential, and commercial settings are more significant in determining what happens in the natural gas industry. This non-electric power demand for natural gas is exogenously given and remains the same for all cases considered.

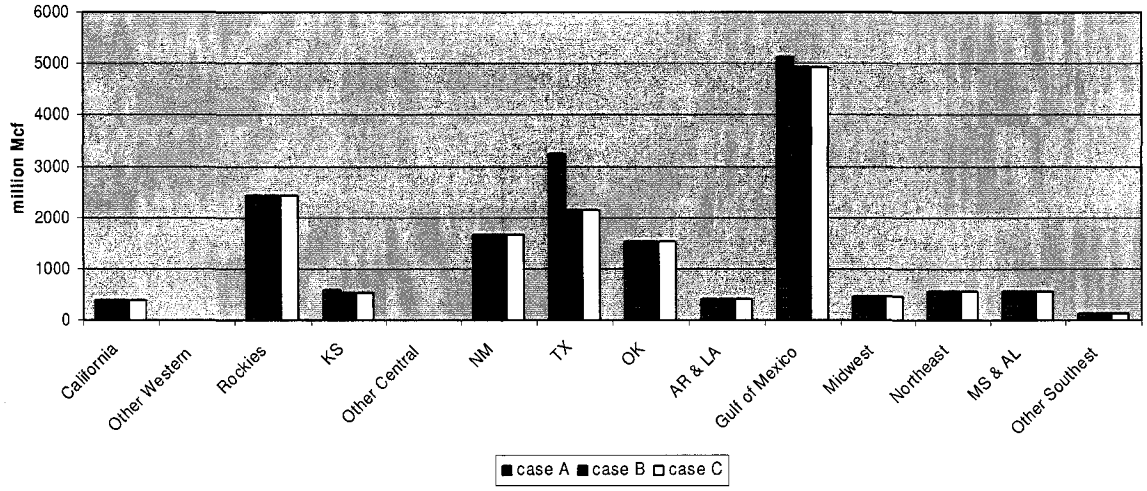

Figure 7.5 – Annual natural gas production

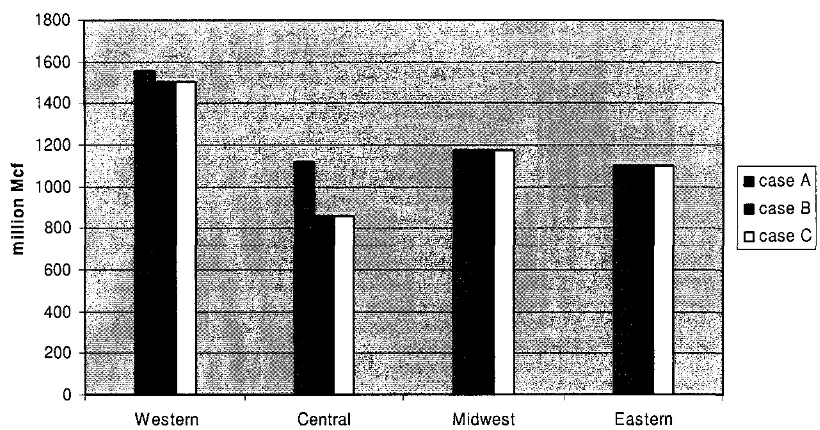

Figure 7.6 – Annual natural gas imports from Canada

Figure 7.7 shows the natural gas flows observed in case B, along with the geographical distribution of the natural gas supplies for all cases, including national production and Canadian imports. The red arrows represent gas transmission links that are most of the time congested. This indicates that, although natural gas supplies decreases in the optimal cases B and C, imports into the Western, Midwest, and Northeast regions and transportation from the Southeast to the Northeast remain heavily congested. Key pipeline capacity expansions should target these corridors.

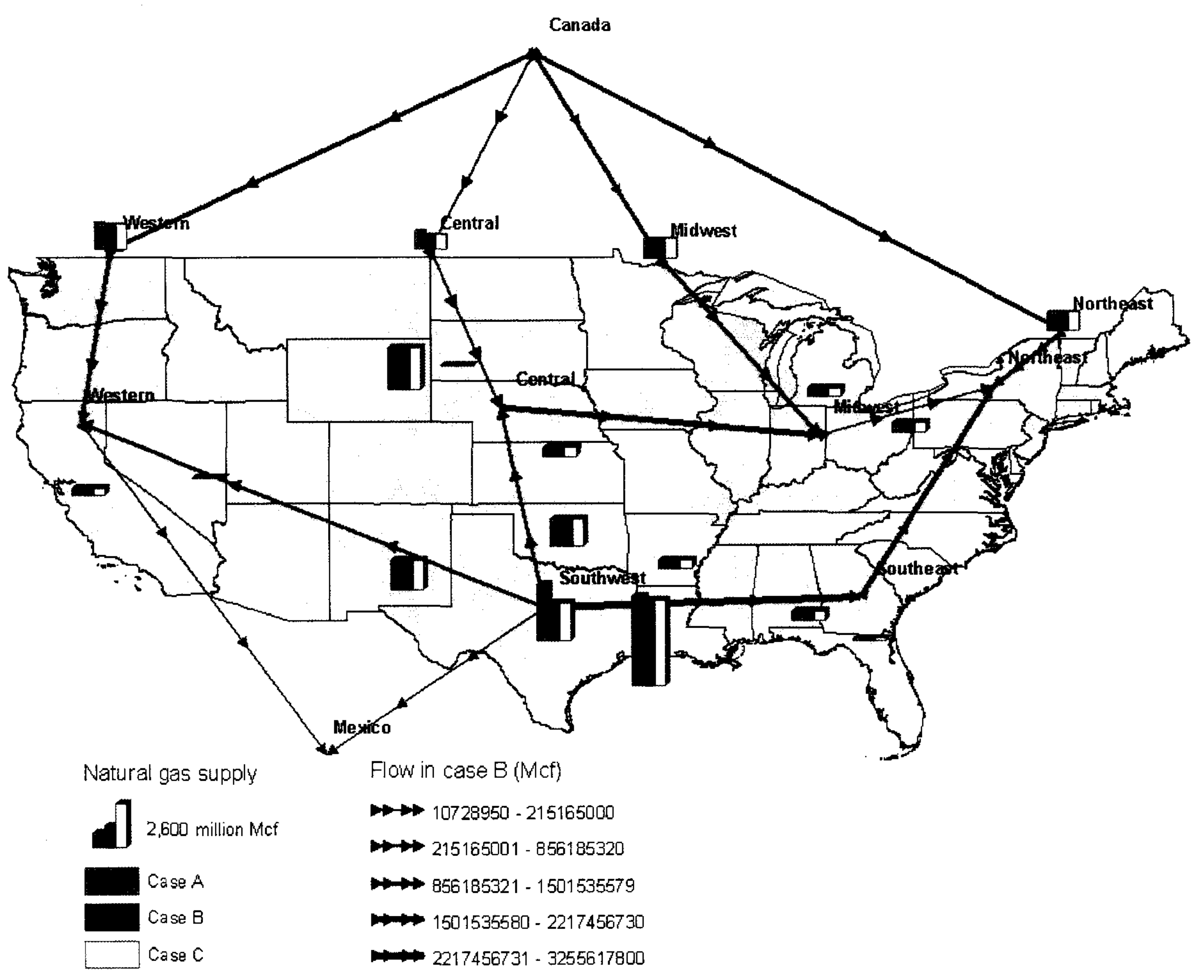

Figure 7.7 – Natural gas transmission flows

Monthly natural gas storage injections and withdrawals are presented in Figure 7.8. As expected, natural gas storage patterns reflect the requirement to meet seasonal fluctuations in demand, clearly dominated by the heating needs of the non-electric power sector end-users, i.e., the industrial, residential, and commercial demand sectors. Storage injections are observed in the offpeak season (April through October), while storage withdrawals occur to meet the higher demands in the peak season (November through March).

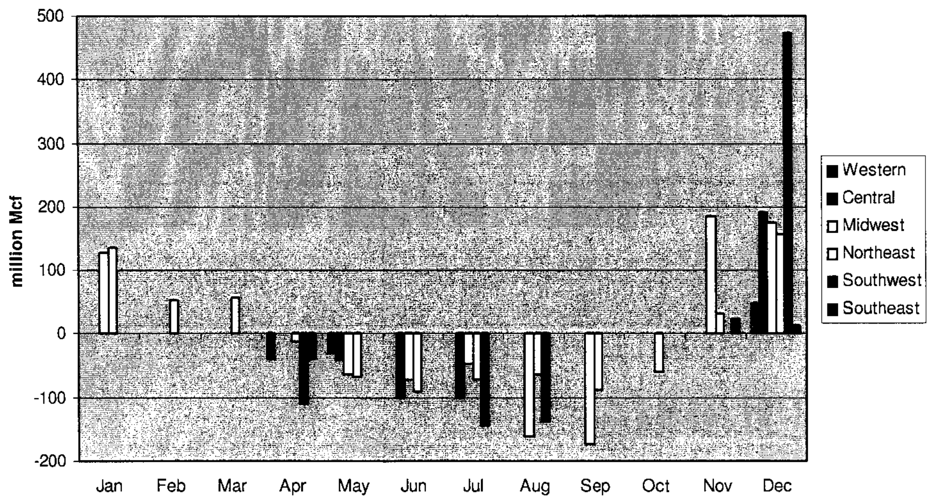

Figure 7.8 – Natural gas storage injections (negative values) and withdrawals (positive values)

7.3.4 Electricity Network

The annual electricity generated from coal and natural gas plants are depicted in Figure 7.9 and Figure 7.10, respectively. In case B, electricity generated from coal-fired units increases across most regions. The most significant increases are observed in MAAC, ECAR, EES, and MAIN. On the other hand, electricity generated from natural gas-fired units decreases significantly in almost all regions, except in ERCOT, where it remains the same, and NWPP and AZNM, where it actually increases. In some regions, namely MAPP, MAIN, ECAR, and MAAC, electricity generation from natural gas is completely eliminated, as a result of a strict merit order dispatch solution (low cost to high cost). Given the characteristics of combustion turbine units (fast start-up and high operating costs), some natural gas-fired units are often used as peaking-load generators. This means that they are needed to operate for a relatively small number of hours to meet peak demand requirements. Therefore, the fact that electricity generation from natural gas-fired units is cut down to zero in some regions may not be a realistic result. Nonetheless, given the potential cost savings that this would represent, it is an indication that utilities in these regions should pay careful attention to the design and implementation of demand side management (DSM) programs that would encourage consumers to modify their level and pattern of electricity usage. Effective DSM initiatives would contribute to the alleviation of peak loading conditions, thus reducing the need for peaking units and associated natural gas consumption. Besides this type of utility-administered programs, local governments and/or regulatory bodies could intervene by establishing energy efficiency standards, for example.

The differences between cases B and C are not very significant. This is because, as a result of cost minimization, the least efficient and most heavily polluting coal plants are already less utilized, even without the emissions constraint in place. In addition, the least expensive types of coal also rank low on sulfur content. Another factor that contributes to these findings is the high efficiency rates of the scrubbers installed in roughly one third of the coal-fueled electric generation capacity.

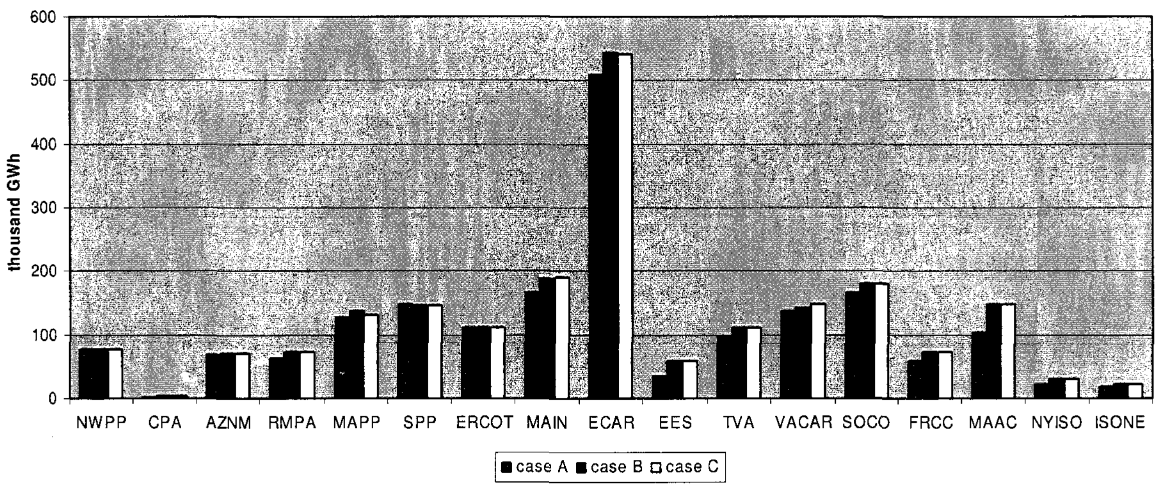

Figure 7.9 – Annual electricity generation from coal-fired units

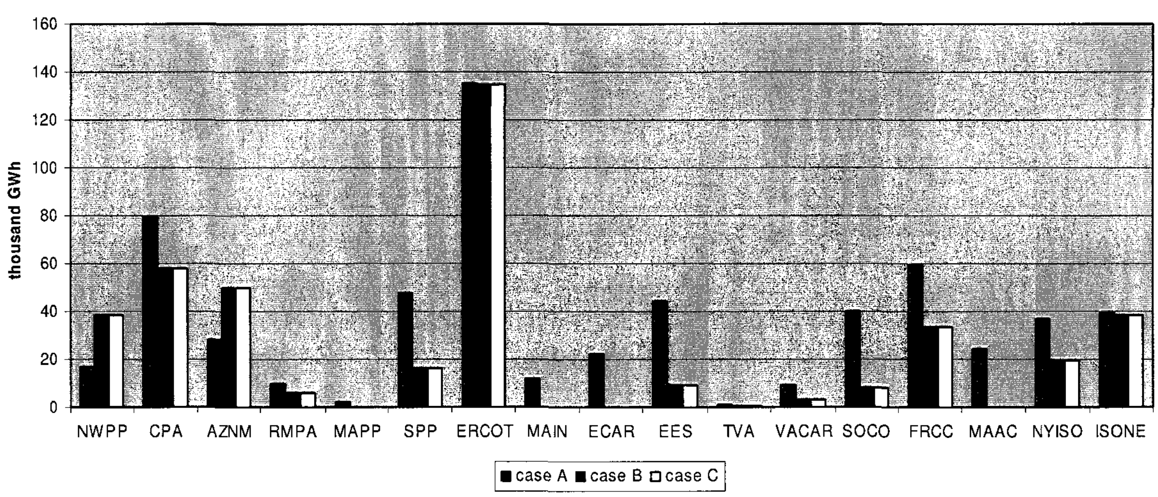

Figure 7.10 – Annual electricity generation from gas-fired units

To illustrate the time evolution of the electricity generation, the monthly generation levels of the coal and natural gas-fired units of ECAR are presented in Figure 7.11. This region was selected for exemplifying purposes for being the one that generated the most electricity. In all cases, the dynamics of the generation outputs reflect the seasonal pattern of demand, which, in the Midwest parts of the country, is characterized by peaking load conditions in the summer and winter. This is not surprising, because electricity demand is driven in part by weather conditions. With the Midwest's cold winters and shorter daylight hours, there is relatively high demand for heating and lighting in that season. In the summer, warm weather results in relatively high demand for air conditioning.

In the optimal cases B and C, electricity generation from coal increases in all months, while electricity generation from natural gas drops to zero. The increase in generation from coal-fired units more than offsets the curtailed generation from natural gas-fired units, which implies that net sales to connecting regions increases.

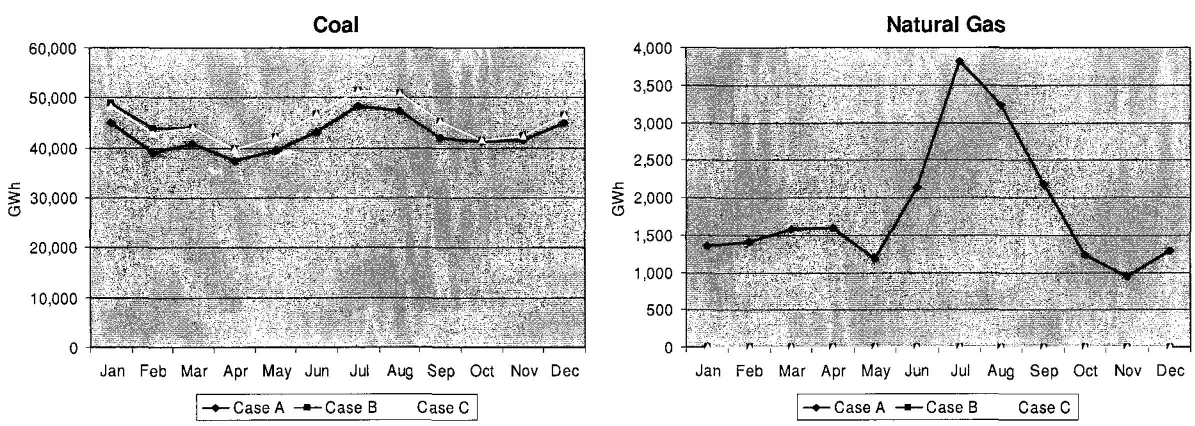

Figure 7.11 – Monthly electricity generation in ECAR

Figure 7.12 shows the annual net interregional transfers of electric power for all regions. Positive values represent net sales and negative values correspond to net purchases. In the reference case, because generation and load levels are fixed at the actual values, electric power trade between regions corresponds to the actual operating levels. In the optimal case B, net trade increases in all regions, but SOCO, MAAC, and ISONE. SPP, which is a net seller of electricity in the reference case, becomes a net buyer in cases B and C, as it replaces its own more expensive gas-fired generation by additional purchases of less costly supply available in neighboring regions, namely MAAP and MAIN. Conversely, TVA is a net buyer in the reference case and becomes a net seller in the other cases, primarily because of increased exports to EES, VACAR, SOCO, and ultimately FRCC.

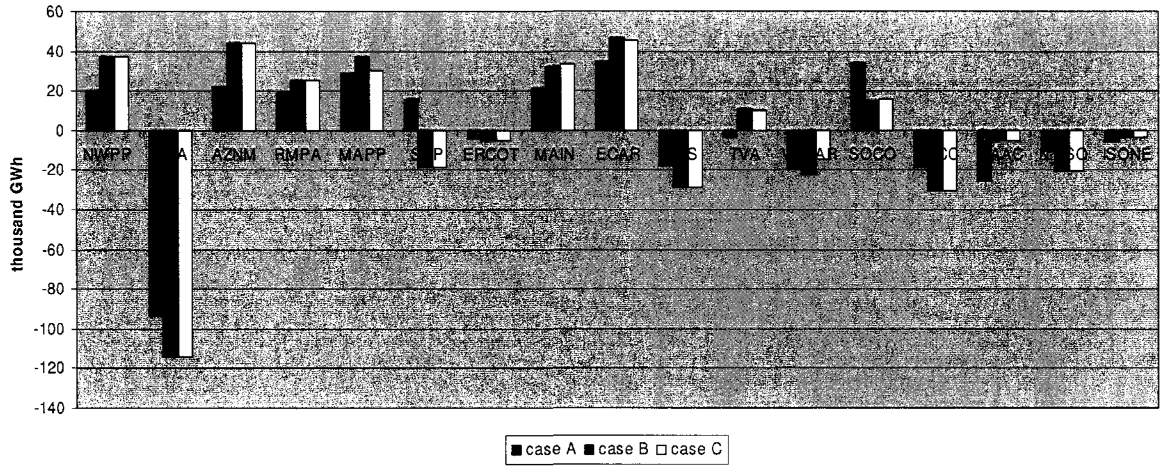

Figure 7.12 – Annual electricity net trade

Figure 7.13 shows the electricity flows among regions observed in case B. The red arrows represent electricity transmission links that are most of the time congested. This is the result of the increase utilization of cheaper coal-fired power plants available primarily in Midwestern and Central regions to satisfy the consumption needs in California, Florida, and the Northeast demand regions.

Given the modeling assumptions, the electricity trade solution obtained for the optimal case is possibly overestimated. The aggregation level considered is defined under the assumption that transmission flows within the regions are unconstrained, which may not be the case. Although interregional transmission is constrained, all generation within a region is assumed equally available at all points of interconnection with neighboring regions. In addition, the transmission capability assumptions between demand regions are derived from the FCITC, which are calculated for specific system conditions and on a non-simultaneous basis. Any changes to the system conditions, such as variations in generation dispatch, can significantly affect transfer capabilities. In addition, simultaneous transfers different from the base value change the actual transmission capability. Therefore, it is likely that the optimal transmission flows are not sustainable or cannot be maintained in a reliable manner. Nonetheless, these results indicate that potential opportunities to increase interregional electricity trade, with the associated economic benefits and environmental impacts, may not be being realized. Although there is very little literature on this matter, a very recent study has identified imperfect information, lags in the scheduling process, forecast errors, and risk avoidance as the main reasons that prevent an efficient electric energy trading activity [153]. In addition, some regions may not have the incentive to increase generation levels for export to neighboring regions, and thus contribute to the national optimal dispatch solution. Imperfections in energy markets may lead to uncertainties in cost recovery, which would prevent utilities for allowing their own marginal cost to increase. These impediments to the efficient trading outcome are generally referred to as seams issues, because they arise at the borders of the ISOs or control areas.

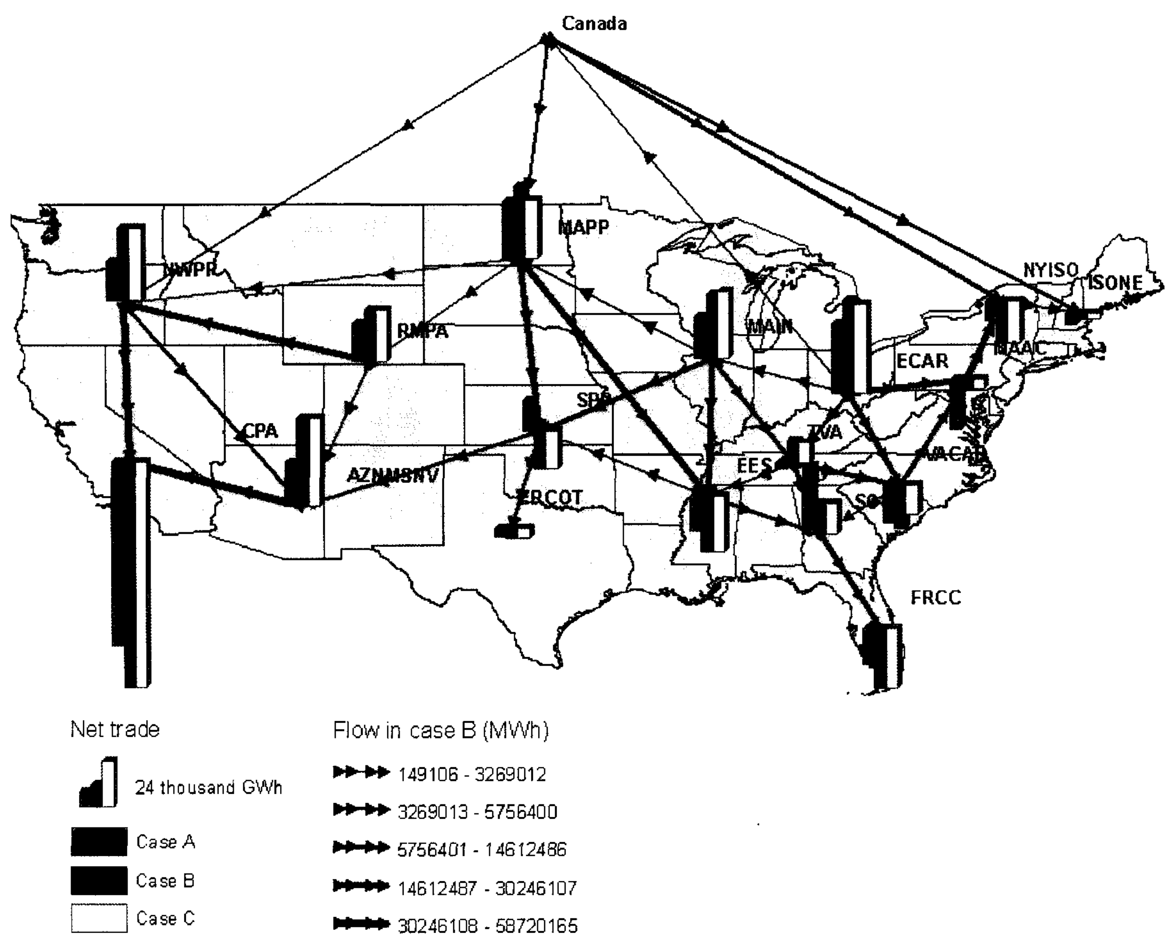

Figure 7.13 – Electricity flows

7.4 NODAL PRICES

The average nodal prices at the demand regions are shown in Figure 7.14. As expected, most of the nodal prices drop when the generation levels are not fixed, as a result of the smaller utilization of higher cost generation from natural gas. MAAC is the region that realized the largest nodal price reduction. Nonetheless, nodal prices actually increase in regions such as NWPP and AZNMSNV, as more expensive supply resources are called on to displace even higher cost units in other regions. This means that the opportunity to reduce the national level total costs come at the expense of some regional nodal prices, which increase in both optimal cases B and C.

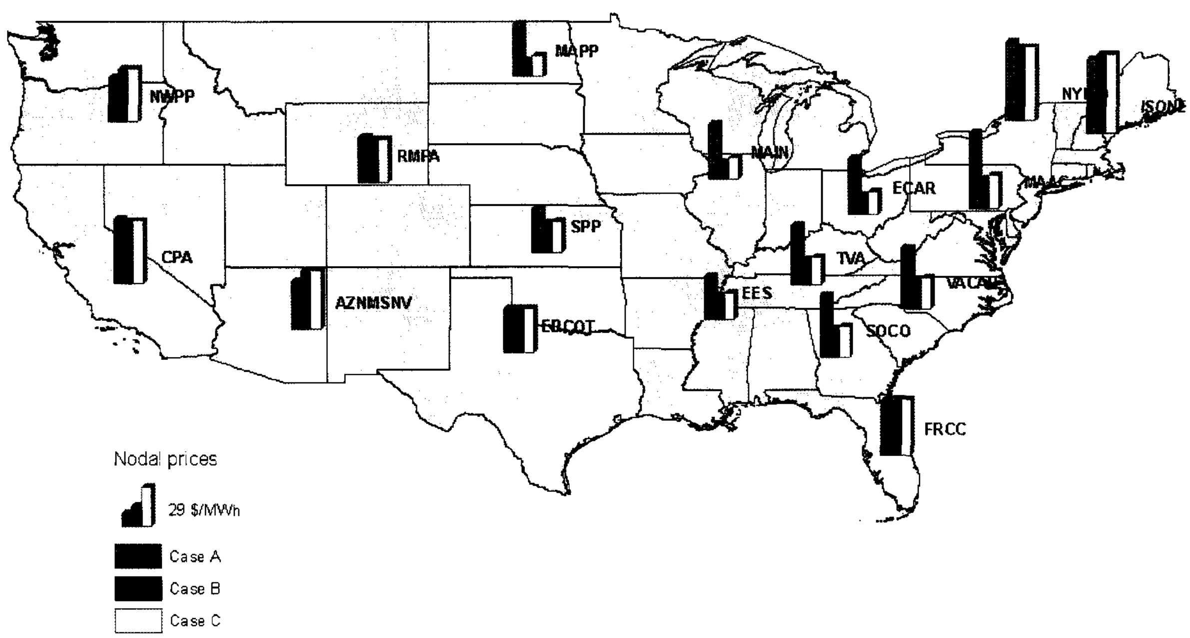

Figure 7.14 – Nodal prices in the demand regions

With the introduction of the environmental constraint, an increase of the smaller nodal prices is observed. This reflects the utilization of more expensive and cleaner coal necessary to satisfy the emissions limit.

The northeast regions of NYISO and ISONE remain with the highest nodal prices and the difference between MAAC and NYISO nodal prices is a clear indication of congestion. Likewise, the difference between the nodal prices in MAPP and the western and southern connecting regions, and the difference between the nodal prices in SOCO and FRCC are also indications that cheaper generation cannot be exported to the higher priced regions, because the electric transmission capacity between the affected regions is fully utilized.

As an example of the evolution of the nodal prices in time, Figure 7.15 shows the monthly nodal prices observed in the MAAC and NYISO regions. In the reference case A, nodal prices are always in the 50-60 $/MWh range, in both regions. In the time interval from January to May and November to December the price differences between these two regions are very small and reflect the effect of transmission losses. However, the divergence observed between June and October is a clear indication of congestion that prevents cheaper generation in the MAAC region to be exported to the higher priced NYISO region. For all months and in both regions, the nodal prices in the optimal cases B and C are below those observed in case A. This is particularly noticeable in the MAAC region, where the more expensive electricity generation from natural gas is replaced by lower cost generation from coal. With increased electricity trade, nodal prices in the NYISO region are not able to match those in MAAC, because the transfer capability between regions is always fully utilized. Finally, it is interesting to note that there are no nodal price differences between cases B and C in the NYISO region, as the marginal unit used is always a gas-fired generator. In the MAAC region, a small increase in the nodal prices is observed in the presence of the environmental constraint, which denotes the utilization of more expensive generators and/or more expensive fuel, in order to comply with emissions requirements.

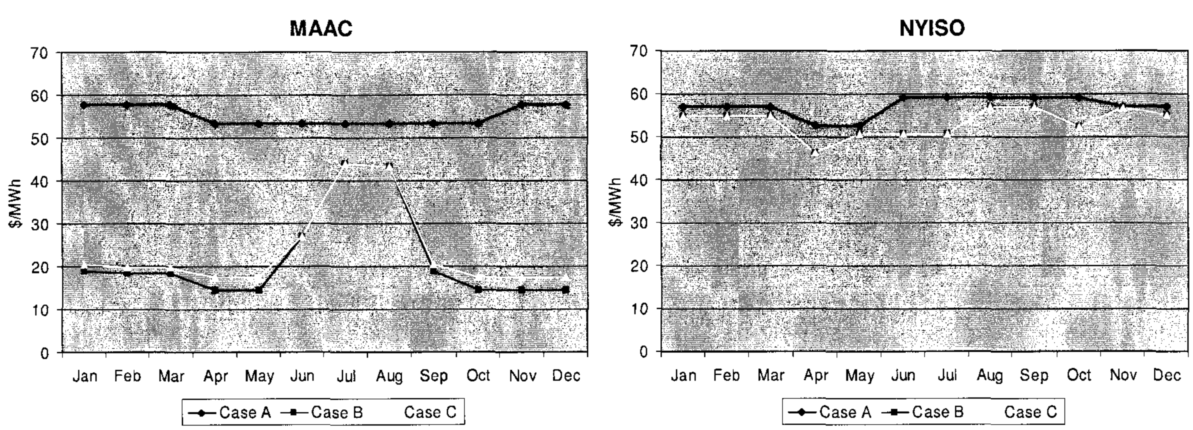

Figure 7.15 – Monthly nodal prices

The national level perspective indicates that an increase in trade would result in better utilization of low cost generators, curtailing usage of higher cost units and allowing customers to benefit from lower prices. However, even if competition were perfect, social benefits would be limited by the transmission system, which would not be able to reduce the price disparity between some regions. On the other hand, a perfect wholesale market for electricity would stimulate efficient transmissions investments, which would resolve congestion. Nonetheless, a recent study shows that relying primarily on a market driven investment framework to govern investments in electric transmissions networks is likely to lead to inefficient decisions [154]. This conclusion is based on the premise that, under more realistic assumptions, not all efficient investments are profitable, because competition is not perfect. Widely documented imperfections in wholesale electricity markets, price distortions, economies of scale in transmission investment opportunities, stochastic attributes of transmission network constraints and associated property rights definition issues, the effects of the behavior of system operators and transmission owners on transmission capacity and reliability, coordination and bargaining considerations, forward contract, commitment and asset specificity issues (sunk costs), market power, and other externalities are identified as potential reasons that may be undermining the performance of competitive markets for electricity. In summary, the theoretical and empirical evidence suggests the need for regulatory intervention to promote not only the socially efficient dispatch and associated electricity trading solution, but also efficient network expansion investment decisions.

7.5 EMISSIONS

Figure 7.16 presents the 2002 vintage allowances allocated to the modeled units, along with the emissions corresponding to the three analysis cases. Case A is configured with the actual emissions level of 9,446 thousand tons. In case B, emissions are not restricted and the SO_2 released by coal-fired generators amounts to 10,141 thousand tons. In case C, emissions are limited by the actual level and the constraint is binding, which means that the national level of emissions obtained is 9,446 thousand tons. Although the aggregated level of emissions released in case A and case C are the same, their spatial distribution is different. In the optimal centralized decision making case, the increased utilization of coal-fired units and associated increased electricity trade affect the spatial distribution of SO_2 emissions, by increasing concentration predominantly in the ECAR and MAAC regions. Note that these regions are the ones that were already emitting the most above their initial allocation, taking advantage of the trading and banking mechanisms. These results show that, although trading of emissions allowances does not change the national aggregate emissions level set by the CAAA, it does tend to minimize the overall cost of compliance.

Some environmentalists and critics of the cap and trade program have raised concerns about its environmental integrity, suggesting that this trading mechanism may lead to the creation of geographic hotspots (localized areas where the amount of pollutant deposited actually increases, as a result of the fact that polluting sources are not uniformly mixed in space) [155], [156]. Nonetheless, empirical studies that analyze state and regional flows in trading show that the SO_2 allowance trading program has not led to regional concentration of emissions [157], [158], [159]. Rather, the authors of these studies argue that the program is helping cut concentrations since the largest sources are those that have reduced emissions the most, smoothing out emissions concentrations instead of concentrating them. This is usually referred to a cooling effect whereby the greatest reductions are in the areas most adversely affected historically. In addition, massive reductions in aggregate emissions accomplished under the Title IV regulations should enable an overall welfare benefit that far outweighs incidental hotspot activity.

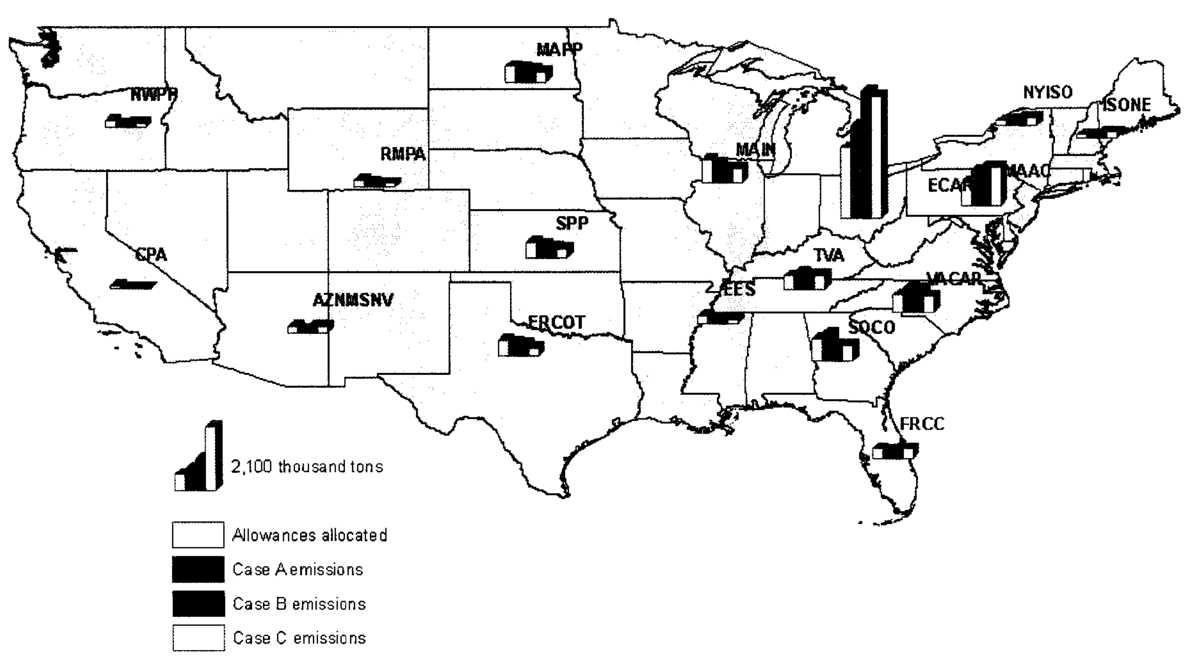

Figure 7.16 – Geographical distribution of SO_2 emissions

CHAPTER 8. CONCLUSIONS AND FUTURE WORK

8.1 CONCLUSIONS

This research work has been motivated by the hypothesis that the current fragmented decision making environment in which coal, natural gas, and electricity firms operate may lead to potential inefficiencies. Given the critical role that these infrastructures represent and their great interdependency, it is of vital importance to keep an overall system perspective, both during planning and in all stages of operation. To the extent that traditional tools and simulation models do not allow for a comprehensive analysis capable of handling the complex dynamics of highly integrated energy systems, individual decision makers support specific procedures and strategies according to their own value system (i.e., economical, technical, organizational, political, and environmental context), which may lead to efficiency losses.

In order to address these issues, this research has presented a model of the national integrated energy system that incorporates the production, storage (where applicable), and transportation of coal, natural gas, and electricity in a single mathematical framework. In general, the model developed can be used to foster a better understanding of the integral role that the coal and natural gas production and transportation industries play with respect to the entire electric energy sector of the U.S. economy. The model represents the major fossil fuel markets for electricity generation (coal and natural gas) and solves for the optimal solution that satisfies electricity demand, deriving flows and prices of energy. Each energy subsystem considers the factors relevant to that particular subsystem, for example, coal transportation costs, or gas transmission capacities. The modeling framework presented integrates the cost-minimizing solution with environmental compliance options to produce the least-cost solution that satisfies electricity demand and restricts emissions to be within specified limits. Conceptually, the model is a simplified representation of the coal, gas, and electricity systems, structured as a generalized, multiperiod network composed of nodes and arcs. Under this approach, fuel supply and electricity demand nodes are connected via a transportation network and the model is solved for the most efficient allocation of quantities and corresponding prices. The synergistic action of economic, physical, and environmental constraints produces the optimal pattern of energy flows.

An important impact of this research work is the potential that it has in motivating the national integrated energy system participants to identify and utilize more efficient flow patterns by overcoming informational, organizational, and/or political barriers, and by targeting investment opportunities that yield the most economic and social benefits. The model can help government and industry analyze a wide range of issues related to the energy sector, such as market studies, strategic planning, economic impact assessment, and air regulatory issues. The methodology presented enables energy companies to carry out comprehensive analysis of their energy supply systems and regulatory bodies to do comprehensive scenario studies of energy systems with respect to environmental impacts and consequences of different regulatory regimes.

The specific contributions of this research can be summarized as follows:

- **Integration of different energy systems in a single analysis framework.** Traditionally, electric power systems have been developed and operated without a conscious awareness and analysis of the implications on the national fuel-electric system. The possibility of power delivery beyond neighboring regions is not usually taken into accounted. Far more remote is the consideration of integrated dynamics with the fuel markets. This research work has focused on developing a tool that enables the analysis of the interdependent electric, coal, and natural gas networks, bridging and cross-fertilizing these traditionally separate fields in a healthy and integrated fashion.
- **Application of generalized network flow algorithms.** The conventional tools that underpin today's modeling, simulation, control, and optimization paradigm are unable to handle the complexity of hybrid, large-scale, time-dependent, and highly interconnected networks that compose the integrated energy system. This research has proposed a new representation of the coal and natural gas networks interconnected with the electricity generation, transmission, and demand that

allows the application of well-established transportation network optimization algorithms. The modeling techniques that have been presented enable the formulation of the complex integrated energy system into a generalized, multiperiod, minimum cost flow problem.

- **Generalization of the power flow concept into a nonspecific energy flow model.** The integrated energy system model that has been presented provides a reinterpretation of the electric power flow concept in terms of a generic energy flow. Instead of studying the movements of coal, natural gas, or electric power through their respective infrastructures, the model proposed focus on generic energy flows through paths of an integrated network. This novel approach of studying the flow of energy elicits a thought-provoking view, while revealing a new perspective in relation to system-wide analysis, operation, and planning.

- **Incorporation of environmental restrictions as complicating constraints.** The SO_2 tradable permit system sets a national limit for SO_2 emissions, while allowing for trading and not imposing any specific compliance strategies. The implications of this environmental policy instrument have been incorporated in the generalized network flow model of the integrated energy system and formulated as a complicating constraint that specifies a flow relationship among several arcs of the network flow model.

- **Compilation of data characterizing the national integrated energy system infrastructures and their operations.** Even though the model presented is a very simplified and high-level representation of the real energy system infrastructures, the data gathering effort has been enormous. Significant amounts of data have been collected from different sources with heterogeneous formats and levels of detail. After processing and resolving some gaps, a comprehensive database characterizing the physical infrastructures and their operations has been developed.

- **Identification of the least cost flow pattern.** Under the assumptions and methodologies used, the optimal energy flow patterns have been identified. In comparison with the actual energy movements of the integrated energy system, the optimal solution has indicated that economic efficiencies are potentially being lost. An overall optimization at the national level has shown that there are opportunities to better utilize low cost generators, curtailing usage of higher cost units and increasing electric power trade, which would ultimately allow customers to benefit from lower electricity prices. On the fuel networks, the optimal solution has translated in increased coal production (mainly from the Powder River Basin), heavier coal movements from the western coal supply regions to the Central and Midwestern consuming regions, and slight decrease on natural gas production and Canadian imposts into the Central region.

- **Analysis of how the decentralization level of decisions affects the economic performance of the system.** Despite the fact that these results may be highly influenced by the assumptions made, namely the aggregated level used, the national optimal solution has indicated that the decentralized level of the decisions making processes, along with imperfect competition, may have a negative effect on the overall economic performance of the system. As restructuring of increasingly interdependent energy markets proceeds, traditionally separate and distinct industries may seek strategic alliances as a mean for improving efficiency. Law makers may then be required to intervene in finding ways to encourage collaboration among rivals without undermining competitiveness.

- **Promotion of efficient investment decisions.** Because nodal prices monetize congestion costs, they provide clear economic signals that indicate where infrastructure improvements should take place to relieve constraints, thus promoting efficient investment decisions. The model has identified critical natural gas pipeline corridors, coal production nodes, and electric transmission lines, i.e., system bottlenecks that are preventing the realization of potential cost savings. For example, the model results have shown that transmission congestion in some areas has caused consumers to pay relatively high prices for electricity even though lower cost generation is available elsewhere. Infrastructure upgrades are increasingly important as the system is stretched to its limits. Governments must ensure that market imperfections are not preventing efficient outcomes to be recognized as profitable investments.

- **Evaluation of the impacts of the SO_2 tradable permit system.** The SO_2 cap-and-trade program is an environmental regulation that limits emissions from electric power generators. The experience to date illustrates that the potential savings from incentive based environmental policies such as the allowance trading program are enormous. However, this research work has suggested that improvements in trading behavior will be increasingly important for the industry to capture these savings. The optimal energy flow pattern solution that has been derived assumes a perfect SO_2 allowances market. In other words, it assumes that there are no impediments to trade and allowances are accordingly moved from account to account to guarantee full compliance with the program, which is a critical matter given the increased utilization of coal-fired generators that correspond to the optimal solution.

8.2 FUTURE WORK

The conclusions available from the analysis described raise interesting issues for a more complete version of the model, and suggest exciting areas of further research. Future work should focus on the following aspects:

- **Improve data quality and quantity.** Many of the assumptions and modeling choices that have been made are the result of data limitations. The network model presented is a simplified representation of the physical infrastructures, establishing the possible interregional transfers to move coal, natural gas, and electricity. A more complete and accurate set of data would facilitate a more comprehensive analysis of the opportunities for additional economic efficiencies than does the high level representation that has been analyzed. In addition, a more detailed portrayal of the integrated energy system would allow a more accurate descriptive type of validation and result in findings with higher confidence levels.

For example, one of the critical assumptions associated with the aggregated level that has been chosen is that electricity flows within each demand region are unconstrained. However, the effects of intraregional congestion, if known, could be introduced indirectly into the model by appropriately calibrating/derating the interregional transfer capabilities.

- **Incorporate uncertainties about certain data parameters.** This research work has proposed a deterministic model of the integrated energy system. The real circumstances in which decisions are made are however characterized by imperfect information about data, namely electricity demands and fuel prices, which justify extending the linear programming methodology that has been presented to a stochastic optimization model. A stochastic optimization problem formulation would enable handling uncertain data, given probabilistic information on the random quantities.

- **Represent the interactions between the physical system and markets.** The dynamics of the fuels, electricity, and emissions markets have not been incorporated in this research work. Nonetheless, markets can interact with the physical system in ways that significantly affect system operations. A possible extension to this work would then be to incorporate the underlined market structures and assess their interplays with the structural aspects of the integrated energy system. This would allow the evaluation of how modifications in the current market structures could affect the energy flows and the overall economic performance of the integrated energy system.

- **Account for the influence of perceived future conditions.** The model proposed for the integrated energy system does not incorporate the effects of perceived future conditions. Nonetheless, current expectations of future conditions are an integral part of real-world judgment and decision-making processes. For example, the allowance price derived by the model does not capture the fact that an expected rise in natural gas prices creates an incentive to increase SO_2 allowances price, as the opportunity of fuel switching is perceived to be less attractive. The task of capturing the real-world decision processes and the complex dynamics of management behavior (as opposed to a purely physical model) could be accomplished by establishing feedback loops between the appropriate decision points, to make explicit causal relationships among the various components of the integrated energy system.

- **Apply the model to address a wide range of issues.** The model developed can be used in supporting public and private decision makers analyze a wide range of issues related to the energy sector, providing explicit national and regional evaluation of the impact of different events, policies, and infrastructure enhancements on electric energy prices and price variability. Examples of issues that can potentially be addressed by the integrated energy model include the following:

  Electricity industry issues:

  - What are the most important seams issues inhibiting the ability to transact electric power across control area boundaries?
  - How would increased transmission capability influence wholesale electricity prices?
  - How would major investment in a specific electricity national or regional generation portfolio affect electricity prices?
  - What are the potential peak demand reductions and energy savings accrued from DSM programs?

  Fuel markets issues:

  - How do high natural gas prices impact the coal industry?
  - How would a major disruption in the coal industry, affecting either coal production levels (e.g., a coal miners strike) or coal deliverability (e.g., a coal train derailment), impact the generation mix?
  - How would increases in coal exports (namely to fast developing economies such as China) affect domestic coal markets?

Air emissions issues:

- How will tighter emissions limits affect SO_2 prices and compliance decisions?
- How would different banking strategies affect SO_2 prices and compliance decisions?
- How would the aggregate level of emissions and their geographical distribution change if states imposed local standards or trading restrictions? What would be the impacts on the fuel and electricity markets?
- How do high natural gas prices drive emissions prices?
- How would CO_2 regulations impact the coal, gas, electricity, and SO_2 markets?

ACRONYMS AND ABBREVIATIONS

AAR	Association of American Railroads
AC	Alternating Current
AGA	American Gas Association
ATC	Available Transfer Capability
ATS	Allowance Tracking System
AZNMSNV	Arizona-New Mexico-Southern Nevada Power Area
Bcf	One billion cubic feet
BTS	Bureau of Transportation Statistics
Btu	British thermal unit
CAAA	Clean Air Act Amendments
CBM	Capacity Benefit Margin
CHP	Combined Heat and Power
CO_2	Carbon dioxide
CPA	California Power Area
CTRDB	Coal Transportation Rate Database
DC	Direct Current
DOE	U.S. Department of Energy
DoD	U.S. Department of Defense
DSM	Demand Side Management
ECAR	East Central Area Reliability
EES	Entergy Electric System
EFOM	Energy Flow Optimization Model
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration
EMCAS	Electricity Markets Complex Adaptive Systems
ENPEP	ENergy and Power Evaluation Program

EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ES&D	Electricity Supply and Demand Database
ETS	Emission Tracking System
ETSAP	Energy Technology Systems Analysis Programme
FASTR	FERC Automated System for Tariff Retrieval
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
FGD	Flue Gas Desulfurization
FOB	Free on board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System
GIS	Geographic Information System
GWh	Gigawatthour (one thousand megawatthours)
IEA	International Energy Agency
INGAA	Interstate Natural Gas Association of America
IPP	Independent Power Producer
ISO	Independent System Operator
ISONE	ISO New England
kW	Kilowatt (one thousand watts)
kWh	Kilowatthour (one thousand watthours)
LDC	Local Distribution Company
LEAP	Long-range Energy Alternatives Planning
LMP	Locational Marginal Price
LNG	Liquefied natural gas
LSD	Lime Spray Drying
LSFO	Limestone Forced Oxidation
MAIN	Mid-America Interconnected Network

MAPP	Mid-Continental Area Power Pool
MARKAL	MARKet ALlocation
Mcf	One thousand cubic feet
MEL	Magnesium-Enhanced Lime
MESAP	Modular Energy System Analysis and Planning
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
MMBtu	One million British thermal units
MMcf	One million cubic feet
MMS	Minerals Management Service
MPS	Mathematical Programming System
MSHA	Mine Safety and Health Administration
MW	Megawatt (one million watts)
MWh	Megawatthour (one million watthours)
NAFTA	North American Free Trade Agreement
NATC	Non-recallable Available Transfer Capability
NEB	National Energy Board
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NO_x	Nitrogen oxides
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
RATC	Recallable Available Transfer Capability
RETscreen	Renewable Energy Technology
RMPA	Rocky Mountain Power Area
RTO	Regional Transmission Organization
SERC	Southeastern Electric Reliability Council

SO_2	Sulfur dioxide
SOCO	Southern Company
SPP	Southwest Power Pool
STB	Surface Transportation Board
Tcf	One trillion cubic feet
TRM	Transmission Reliability Margin
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
TWh	Terawatthour (one million megawatthour)
VACAR	Virginia-Carolinas
WECC	Western Electricity Coordinating Council

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