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Department of Energy
Washington, DC 20585

July 25, 2001

MEMORANDUM FOR: Elizabeth Shearer
Director
Federal Energy Management Program

FROM: Lawrence R. Oliver
Assistant General Counsel
Energy Efficiency

SUBJECT: Request for Meeting From Energy Company

Over the past several days I have had telephone conversations with Leonard Rawicz, an attorney in the Washington office of Skadden, Arps, Slate, Meagher and Flom. Mr. Rawicz is Washington counsel for Real Energy, a California cogeneration company (www.RealEnergy.com). Real Energy generates electricity and thermal energy on-site and at lower cost than the purchasers would pay to a local utility. This cogeneration system has been installed at several sites in California. Real Energy is interested in installing its cogeneration systems at Federal sites. The real issue is whether cogeneration projects can use the ESPC vehicle.

The president of Real Energy has requested a meeting with appropriate FEMP officials to discuss what would be the best way to facilitate his activities at Federal sites. Officials for Real Energy have already briefed officials at the White House, who are trying to facilitate the use of cogeneration at Federal sites. I have attached the briefing papers used by representatives from Real Energy to the brief the National Energy Policy Development Group in June of this year.

The president of Real Energy will be in DC tomorrow and would like to meet with FEMP representatives Thursday afternoon or Friday morning. Let me know if you, or other representatives from your office, are available so that I can get back to Mr. Rawicz.

cc: Lee Liberman Otis, GC-1
Eric J. Fygi, GC-2
Neal Strauss, GC-70
Mary Anne Masterson, GC-61
Victor Petrolati, EE-90

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DOE024-0898

RealEnergy

A Presentation For:

The National Energy Policy Development Group

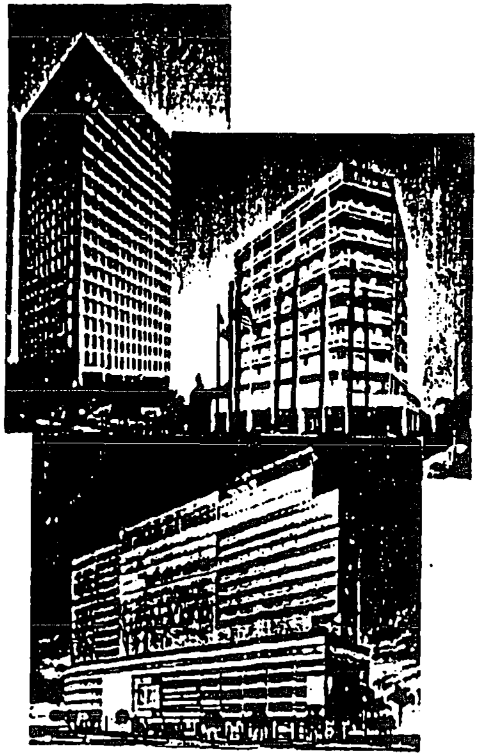
Using Distributed Energy Resources To Solve the Near and Long Term Energy Issues in California and the US

June 2001

National Energy Policy Development Group

Distributed Energy Resources (DER)

National Energy Policy Challenges



Three Challenges:

- *Use Energy More Wisely*
- *Repair and Expand Our Energy Infrastructure*
- *Increase Supplies While Protecting the Environment*

RealEnergy

Goals

- Utilize DER Benefits as a Key Component of the National Energy Policy
- Solve the Electric Grid Infrastructure Problem
- Remove Barriers to DER Implementation
- Provide Incentives for DER Implementation
- Engender Political Support for Environmentally Responsible DER
- Create Substantive Large Scale DER Development Programs

RealEnergy

What is DER?

DER is distributed generation / combined heat and power located at the point of consumption.

- **Most DER also = energy efficiency, "the use of less energy to do the same amount of work" (National Energy Policy Report)**
- **DER is optimally sized to meet the requirements of the facility**
- **Typical DER technologies include:**
  - Combined heat and power (CHP)
  - Internal combustion engines micro-turbines, mini-turbines, and spark ignition
  - Fuel Cells
  - Solar Photovoltaics
  - Small wind and/or hydro generators
  - Storage devices such as flywheels and batteries
  - Energy management technology and software

RealEnergy

How Does It Work?

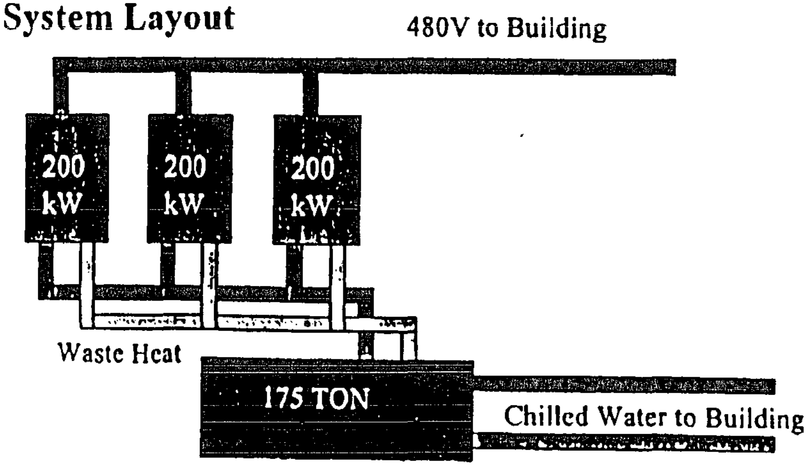
RealEnergy generates power for part of the building's peak demand on-site with clean generation machines, that also utilize otherwise wasted heat energy to further reduce the building's dependence on the electric grid. This solves two problems at once:

- Adds generation capacity and reduces use of grid supply
- Adds transmission and distribution capacity by avoiding the electrical transmission and distribution system

How is it done on site?

A simple generation system like the one shown below is installed, owned and operated by RealEnergy and managed over the internet

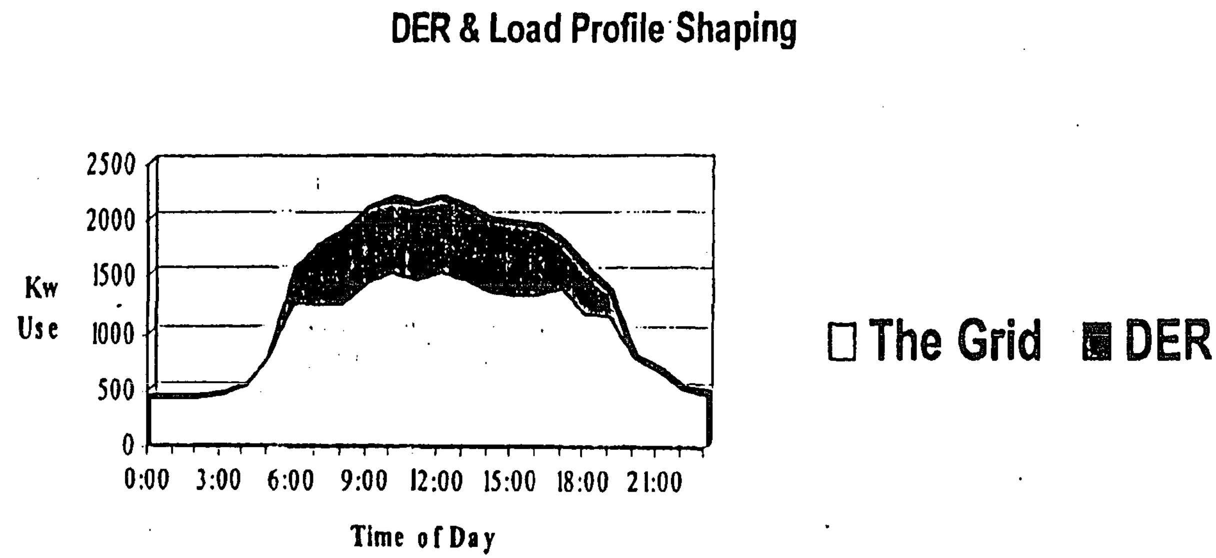
System Layout



What is the Generator?

We currently use the most readily available, most reliable, internal combustion engines (like the one in your car), in the future we will replace those systems with newer technologies like Fuel Cells, Micro and Mini turbines and other types of more efficient, lower maintenance generators, as they become available.

DER's Impact – Grid Relief



Typical Office Building Load Profile

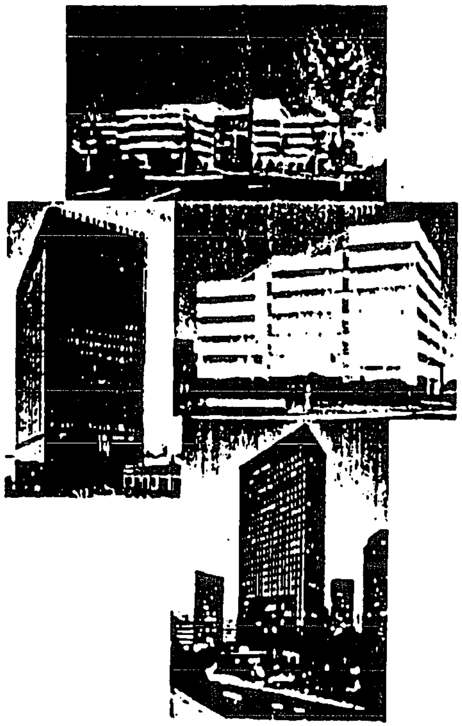
RealEnergy

Why Does DER Support National Energy Policy?

- DER brings new generation on line in half the time as large central station power plants.
- DER increases the efficient use of scarce resources.
- DER puts generation at the point of consumption delivering benefits where most needed.
- DER is a valuable tool in facilitating the development of an efficient and open energy market.
- DER increases grid reliability.
- New DER technologies preserve or enhance environmental quality.
- DER gives customers a real tool to manage their energy reliability and price risk

RealEnergy

How Can We Help Solve the Near and Long Term Problem



What is the best way to make this happen fast?

Well capitalized small generation companies can step in and quickly build a on-site generation in conjunction with the existing utility.

Over the next 10 years DER accounts for 10% of the overall grid capacity, but account for a much greater percentage of that all important "peak" energy supply.

In essence, RealEnergy and DER go directly to the source of the problem, the high peak period energy users, who are unable to effectively reduce their demand, and therefore can produce the same effect through producing a portion of their peak needs on-site.

RealEnergy

Action Plan Congressional / Federal Actions to Facilitate Deployment of DER

Legislation

- Proposed bills H.R. 1045, H.R. 778, S. 207 and S. 597 are a good starting point, but need additional measures

Interconnection (IC)

- Violation for local distribution company to thwart deployment of non-LDC owned DER
- When LDC fails to process IC in timely manner, IC applications deemed accepted by default
- Recognize IEEE IC standard as national standard

Environmental

- Establish national methodology for determining environmental impact of DER:
  - Output based efficiency measures in including thermal energy recovery
  - Quantifying the environmental benefits of avoided line losses
  - Standardized emission factors for air permitting health risk assessments

Natural Gas

- Guarantee access to gas markets at reasonable terms and conditions
- Facilitate development of a national, private DER gas market clearinghouse

Tax

- Create equitable tax treatment and depreciation schedules (5-7 year life)
- Create scaled tax credits for deployment of clean DER technologies

Federal Program

- Create program to facilitate and or require deployment of DER in federal facilities

RealEnergy

National Energy Policy Development Group

Commercial Real Estate & Energy Use

Public & Private Investment Partnership

Create economic incentives for the private sector to develop new DER infrastructure to accelerate the speed of execution

The underlying economics of on-site generation, while maintaining connection to the grid, accomplishes the following:

- Utilizes private and public capital to help solve grid infrastructure issues
- Creates a long term solution
- Encourages clean, reliable, new energy infrastructure that can be developed in months vs. years

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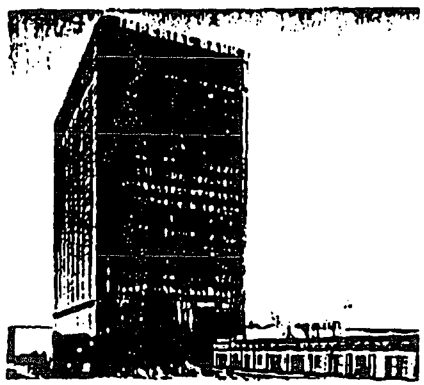
National Energy Policy Development Group

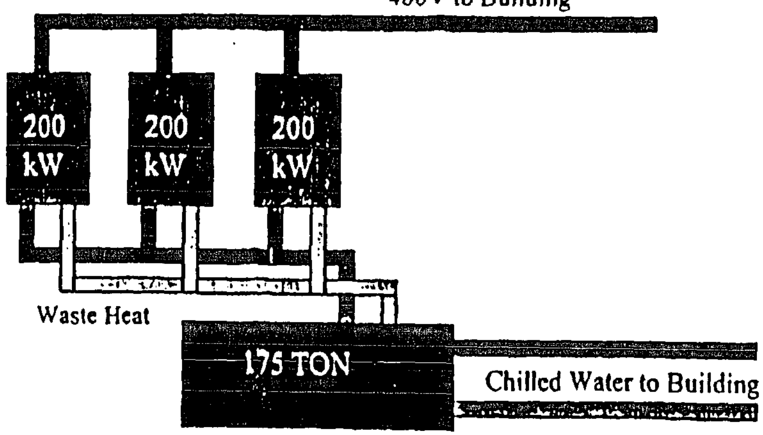
Sample Projects

Sample Project – Imperial Bank Tower

ARDEN Realty - DER



System Layout



The Client

- Arden Realty is a publicly traded Real Estate Investment Trust ("REIT") and the largest office landlord in Southern California

The Building

- 500,000 S.F. Class "A" high rise office tower in downtown San Diego

RealEnergy System

- 600 kW - Natural Gas Fired Internal Combustion Engines which exceed the standards set by the San Diego Air Quality Management District.
- 175 TON absorption chiller
- 4,032 annual kW hours (46%) runtime
- Energy Savings of $62,000
- **Total Peak Demand Reduction of 775 kW**
- Additional chilling capacity and potential for dedicated backup for one or more tenants

RealEnergy

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CONGRESSWOMAN
ROSA L. DELAURO
FAX TRANSMISSION

To: Secretary Abraham **Date:** 3/23/01

Fax #: 586-7644 **Pages:** 2

From: 2001-007915 Mar 23 A 11:36

Comments:

★ 2262 Rayburn Building ★ Washington, DC 20515 ★
★ Phone: (202) 225-3661 ★ Fax: (202) 225-4890 ★

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Congress of the United States
Washington, DC 20515

March 21, 2001

The Honorable Spencer Abraham
Secretary of Energy
Forrestal Building
Washington, D.C. 20585

Dear Secretary Abraham:

As you are aware, our nation is confronting high energy prices and unreliable energy supplies that threaten to slow economic growth and have the potential to produce further energy disruptions this Spring and Summer. In an effort to adequately address this problem, we would like to invite you to meet with the Democratic Caucus Energy Task Force next week to discuss the current energy situation and the Administration's apparent effort to overhaul the national energy policy.

As committed leaders on energy issues in the Congress, we are concerned about the position the Administration has taken in recent days. Americans across the country are facing soaring gasoline prices at the pump, natural gas prices that have more than tripled, and electricity costs that have been volatile all over the country, particularly the West coast. As a result, home heating bills have increased by as much as three fold from last year's extremely high prices.

The Democratic Caucus Energy Task Force is moving closer to developing a comprehensive energy policy, and we strongly believe that we must be mindful of both short-term and long-term needs. Adopting a policy that strengthens our economy, protects our environment, and keeps our nation secure is our first priority. We would appreciate the opportunity to meet with you and hear from you about your view of the current situation, as well as discuss with you in depth about the proposed budget for the Department of Energy.

We look forward to finding common ground with you and hope that you will be able to join us. Please confirm with Soña Garcia at the Democratic Caucus at 226-3210.

Sincerely,

Richard Gephardt

Charlie Stenholm

23514

John F. Tierney

Brad Carson

Nick Lampson

Jim Matheson

John W. Olver

Joe Baca

Ron Kind

Peter DeFazio

Charles B. Rangel

Bob Filner

Edward J. Markey

Anna G. Eshoo

Maxine Waters

Tim Holden

Jim Oberstar

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

2001-002798 Feb 1 p 4:07

OFFICE OF THE CHAIRMAN

January 30, 2001

The Honorable Spencer Abraham
Department of Energy
1000 Independence Ave., SW
Rm. 7-A257 (7th Floor)
Washington, DC 20585

Dear Secretary Abraham:

As we previously have discussed, I am designating my Legal Advisor, Robert H. Solomon, to serve as my representative on the federal energy task force. Frankly, my preference would be to serve myself. Unfortunately, my presence on the task force could be more counter-productive than productive. This is because of the status of the Federal Energy Regulatory Commission as an independent agency that, under the Administrative Procedure Act and relevant ex parte limitations, is obligated to base all decisions on record evidence available to all of the parties. The Commission currently is considering requests for rehearing of its December 15, 2000 order on California remedies. In addition, the Commission is considering various petitions and motions that concern, in various respects, the issues raised in the December order. I would be unable to offer any but the most general of opinions concerning the California situation. My concern is that opponents of the Commission's order would seize upon my participation in the task force as grounds for recusal.

I am confident that Mr. Solomon will ably represent me and the Commission. Please do not hesitate to contact him on any matter related to the task force's operations. As for myself, I look forward to working with you and cooperating to advance market-oriented solutions to our nation's energy woes that will truly benefit all Americans.

Sincerely,

Curt L. Hébert, Jr.
Chairman

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Waste-to-Energy:

A tax credit for new, waste-to-energy facilities or new generating units at existing facilities continues the federal government's policy to encourage clean, renewable electricity, and promote energy diversity while helping cities meet the challenge of trash disposal. Here's why the tax credit deserves your support ...

- Waste-to-energy facilities generate electricity and steam using municipal solid waste (garbage) as fuel. The garbage burns in specially designed boilers to ensure complete combustion, and new Clean Air Act standards require facilities to employ the most modern pollution control equipment available to scrub emissions. The result is clean, renewable energy.

- Nationwide, 85 waste-to-energy plants supply about 2400 megawatts of electricity to the grid. Plants operate 365-days-a-year, 24-hours a day. Facilities average greater than 90% availability of installed capacity. Waste-to-energy plants generally operate in or near an urban area, easing transmission to the customer.

- Facility revenues come from fees paid to dispose of the garbage and the price paid for electricity generated by waste-to-energy plants. New facilities or new generating units built at existing facilities require significant capital investment. The capital, and the operation and maintenance (O&M) costs at a facility equal about $100 for each ton of garbage processed at a facility. On an energy revenue basis, about 20 cents per kWh would be required for capital and O&M. For example, a facility that processes 2000 tons of trash each day into 60 MW of electricity would require about $200,000 in revenues daily, coming from either disposal fees or electricity revenues, or both.

- Waste-to-energy power must be sold as "base load" electricity and cannot be operated to supply "peak load" power simply because there is a constant need for trash disposal by combustion that keeps power generation steady and reliable.

- Similar to other alternative energy sources, waste-to-energy plants are qualified facilities (QFs) eligible under PURPA for mandatory power purchase at avoided cost. Most existing facilities have been financed based, in part, on long-term PURPA contracts that run commensurate with the facility debt.

- The biomass content of waste-to-energy's fuel, municipal solid waste, is about 75% on a Btu-output basis.

- Power purchasers no longer offer long-term PURPA contracts. Power generated by new waste-to-energy facilities or new units at existing facilities will be sold as base load, and the power price will fluctuate on a 24-hour basis at the market clearing price (i.e., waste-to-energy power will be bid at "0" cents and ride with the market.)

- The market price and disposal fees will, on average, not be sufficient to cover the cost of a new waste-to-energy unit. A tax credit is needed to encourage this form of clean, renewable electricity.

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April 12, 2001

Mr. Joseph T. Kelliher
Senior Policy Advisor
Office of the Secretary
U.S. Department of Energy
Room 7B-252
1000 Independence Ave., SW
Washington, D.C. 20585

Dear Mr. Kelliher:

Green Mountain Energy Company greatly appreciated the opportunity to meet with you last week to discuss the development of national energy policy. As a follow-up to that meeting, we would like to provide in writing some information about Green Mountain Energy and a few thoughts regarding competition in the electric industry as a key component of our national energy strategy.

Since its inception in 1997, Green Mountain Energy Company has been committed to using the power of customer demand to help change the way power is made. As a result of its activities in competitive markets to date, the company has spurred the development of several new renewable energy projects, including one of the largest wind farms on the East coast, the first new wind turbines to be built as a result of customer demand in California, and the largest solar array in the San Francisco Bay area.

Green Mountain Energy currently supplies cleaner and renewable electricity to residential, business and government consumers in California, Pennsylvania, New Jersey and Connecticut, and we plan to expand nationwide as more states open their energy markets to competition. Near-term plans include entering the Texas market when the state begins its pilot program in June, 2001, and starting service in September, 2001, to over 400,000 residential customers in Ohio pursuant to a six-year agreement with the Northeast Ohio Public Energy Council ("NOPEC"), a public electricity buying group which represents households across eight Ohio counties.

Green Mountain Energy firmly believes that effective competition in the electric industry can produce benefits for even the smallest customers and is part of the solution to, rather than the cause of, current problems in the western wholesale power markets. We also believe that competition can be an important complement to responsible policy initiatives in support of the environment. Competition presents the opportunity for choice, and choices available in competitive energy markets today include products that are significantly cleaner and higher in renewable content than traditional system power. Moreover, experience in markets to date clearly demonstrates that a significant percentage of switching customers will choose energy products based on their environmental characteristics as well as price. In addition, in several situations where significant blocks of customers were up for bid, Green Mountain Energy, at least, has been able to bid successfully with energy products that are significantly cleaner than

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system average power. In short, the potential for the market to impact how power is made in the future is significant, and grows as consumers become more educated about the environmental consequences of alternative power generation sources.

The potential economic and environmental benefits of competition, however, will not be realized without support and leadership from policymakers. This is a critical time for the competitive energy industry. Recent events in California, high prices in wholesale markets across the country, less-than-effective federal regulation of the interstate transmission grid, and a variety of flawed state restructuring programs are making it increasingly difficult for competitive suppliers to deliver to customers the benefits that would flow from free and fair competition. A number of states are delaying their restructuring programs or considering price control measures that are likely to kill off the competition that would provide the best long-term protection for customers. Leadership is needed now on the federal level to address directly the obstacles to competition that are within the federal government's control, and to provide guidance and encouragement to the states to address effectively those issues within their jurisdiction. We urge the Administration to provide that leadership as part of its national energy policy.

Specifically, we urge that the national energy policy, at a minimum, incorporate the following two elements with respect to electric industry restructuring:

- **Support for federal legislation that 1) assures a robust interstate transmission grid, 2) clarifies federal/state authority over the interstate grid, and 3) mandates efficient interconnection with the transmission grid.** These issues are addressed in a recent letter to you from the Electric Power Supply Association, of which Green Mountain Energy is a member. We will not repeat its discussion of the issues here, but commend EPSA's letter for your consideration.

- **Encouragement of, and support for, retail electric competition.** As described above, it is important that the states and the public hear that effective competition in the energy industry, at both the wholesale and retail levels, will benefit customers and is part of this nation's energy policy. There is much that the federal government could do now to promote competition by, for instance, rationalizing a hodgepodge of state rules and procedures, limiting monopoly functions, and providing tax incentives for restructuring investments. But even if, as many have suggested, the time is not right politically for federal action effecting retail electric restructuring, it is still possible to set a broad direction and begin plotting a course toward full competition. Currently, the Federal Trade Commission, at the request of Congress, is considering comments and developing a report on what is working and what is not in retail electric competition programs, and on what additional federal legislation or regulation might be desirable. Green Mountain Energy urges the Administration to ensure that this is a serious effort, and to utilize the resulting FTC report to inform further direct federal action and/or to press states to reform existing programs and implement new programs that will bring the benefits of competition to customers. The FTC has played the role of advocate and expert advisor to states before, and might productively play such a role with respect to retail electric competition.

Of course, as a marketer of and advocate for renewable energy, Green Mountain Energy also urges the Administration's aggressive support for renewable energy as part of our national energy strategy.

Thank you again for the opportunity to meet and to provide you with our views on electric restructuring and national energy strategy. We are, of course, available to discuss these issues in greater detail at any time.

Sincerely,

Karen O'Neill
Vice President, New Markets
Green Mountain Energy Company

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Bills of DOE Interest 1999

House:

H.R. 11	(Bilbray) to amend the Clean Air Act to permit California State regulations regarding reformulated gas to be applied only in certain areas within the State.
H.R. 28	(Shays) to provide Federal employees greater access to child care services.
H.R. 45	(Upton) to amend the Nuclear Waste Policy Act of 1982 to establish an interim storage facility for nuclear waste.
H.R. 53	(Watkins) to provide a tax credit for marginal oil and natural gas well production.
H.R. 55	(Dreier) to make the Federal Employees health benefits program available to individuals age 55 to 65 who would not otherwise have health insurance.
H.R. 82	(Bilirakis) to exclude the Civil Service Retirement and Disability Fund from the budget of the United States Government.
H.R. 88	(Brown of California) to repeal a requirement regarding data produced under Federal grants and agreements awarded to institutions of higher learning, hospitals, and other nonprofit organizations.
H.R. 91	(Clay) to amend the Family and Medical Leave Act of 1993.
H.R. 110	(Cummings) to make long-term care insurance available to Federal employees and annuitants.
H.R. 142	(Gekas) to prevent Government shutdowns.
H.R. 162	(Holden) to provide a tax credit to promote the conversion of U.S. coal and domestic carbonaceous feedstocks into liquid fuels.
H.R. 192	(Manzullo) to establish judicial and administrative proceedings for the resolution of year 2000 processing failures.
H.R. 206	(Morella) to provide Federal employees greater access to child care services.
H.R. 208	(Morella) to allow certain rollover distributions to be contributed to accounts in the Thrift Savings Plan and eliminate certain waiting period requirements for participating in the Thrift Savings Plan.

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H.R. 209 (Morella) to help Federal agencies license Federally owned inventions.

H.R. 232 (Regula) to provide for a two-year Federal budget cycle.

H.R. 260 (Scarborough) to provide additional tax incentives for the use of clean-fuel vehicles by certain businesses.

H.R. 279 (Sweeny) to require preemployment drug testing for applicants for Federal employment.

H.R. 294 (Sweeny) to require Federal agencies to establish procedures for assessing whether their regulations result in the taking of private property.

H.R. 305 (Towns) to establish an Office of Inspector General Oversight Council.

H.R. 314 (Vento) to require that wages paid under a Federal contract be greater than the local poverty line.

H.R. 341 (Andrews) to establish the Fund for Environmental Priorities using consumer savings resulting from retail electricity choice.

H.R. 350 (Condit) to improve congressional deliberation on proposed Federal private sector mandates.

H.R. 354 (Coble) to protect certain collections of information.

H.R. 380 (Greenwood) to authorize a program to improve various aspects of the oilheat industry.

H.R. 387 (Lobiondo) to prohibit certain oil and gas leasing activities on parts of the Outer Continental Shelf.

H.R. 388 (Lobiondo) to prohibit the Secretary of the Interior from issuing oil and gas leases on certain parts of the Outer Continental Shelf.

H.R. 393 (George Miller of California) to amend the Uranium Mill Tailings Radiation Control Act of 1978 to provide for the remediation of the Atlas uranium milling site near Moab, Utah.

H.R. 409 (Portman) to improve the performance of Federal financial assistance programs.

H.R. 416 (Scarborough) to rectify certain retirement coverage errors affecting Federal employees.

H.R. 423	(Thomas) to allow a five-year carryback for tax purposes for losses attributable to mineral operations of oil and gas producers.
H.R. 436	(Horn) to amend Federal management and debt collection practices, Federal payment systems, and Federal benefit programs.
H.R. 439	(Talent) to minimize Federal paperwork demands on small businesses, educational and non-profit institutions, Federal contractors, State and local governments, and others through the use of alternative information technologies.
H.R. 446	(Bentsen) to eliminate tax subsidies for ethanol fuel.
H.R. 457	(Cummings) to increase the amount of leave available to a Federal employee who serves as an organ donor.
H.R. 460	(Gallegly) to provide that the mandatory separation age for Federal firefighters be the same as that for Federal law enforcement officers.
H.R. 483	(Morella) to make the percentage limitations on individual contributions to the Federal employee Thrift Savings Plan more consistent with the dollar amount limitation on elective deferrals.
H.R. 490	(Smith of Texas) to require the Secretary of Energy to purchase additional petroleum for the Strategic Petroleum Reserve.
H.R. 493	(Stearns) to provide for a biennial budget process and a biennial appropriations process and to enhance the oversight and performance of the Federal Government.
H.R. 494	(Thomas) to amend the regulatory process under the Endangered Species Act.
H.R. 527	(Andrews) to cancel contracts between the U.S. and a contractor who has violated the Davis-Bacon Act repeatedly and to require the disclosure of certain payroll information under contracts subject to the Davis-Bacon Act.
H.R. 542	(Foley) to reduce the number of Trident ballistic missile submarines subject to a statutory limitation on retirement or dismantlement of strategic nuclear delivery systems and to provide that any funds saved by retiring these submarines be used for national missile defense programs.
H.R. 558	(Regula) to provide for the retrocession of the District of Columbia to the State of Maryland.

H.R. 574	(Pombo) to require peer review of scientific data used in support of Federal regulations.
H.R. 602	(Scarborough) to provide for a program under which long-term care insurance may be obtained by Federal employees and annuitants.
H.R. 617	(Degette) to ensure full Federal compliance with the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (Superfund).
H.R. 623	(Knollenberg) to amend the Energy Policy and Conservation Act to eliminate regulation of certain plumbing supplies.
H.R. 657	(Sweeney) to reduce acid deposition under the Clean Air Act.
H.R. 666	(Brown of California) to authorize the Secretary of Energy to establish a multi-agency program to promote energy efficient economic development along the border with Mexico through the research, development, and use of new materials.
H.R. 667	(Burr of North Carolina) to remove Federal impediments to retail competition in the electric power industry.
H.R. 674	(Johnson of Texas) to clarify that natural gas gathering lines are seven-year property for purposes of depreciation.
H.R. 680	(Luther) to reduce the number of executive branch political appointees.
H.R. 721	(Hayworth) to provide for tax-exempt bond financing of certain electric facilities.
H.R. 750	(Thomas) to provide a five-year extension of the tax credit for producing electricity from wind.
H.R. 760	(Sensenbrenner) to extend the research tax credit permanently.
H.R. 775	(Davis of Virginia) to establish procedures for civil actions relating to the failure of a device or system to process the transition from the year 1999 to the year 2000.
H.R. 781	(Andrews) to require a preference for Federal contractors who hire welfare recipients.
H.R. 811	(Wynn) to prohibit under the Petroleum Marketing Practices Act transferring franchises and fixing motor fuel prices in certain instances.

H. R. 835	(Johnson of Connecticut) to extend the research tax credit permanently.
H.R. 870	(McCrery) to change the determination of the 50,000-barrel refinery limitation on oil depletion deduction from a daily basis to an annual average daily basis.
H.R. 877	(Stearns) to provide for comparable treatment of Federal employees and Members of Congress and the President when the Federal Government shuts down.
H.R. 883	(Young of Alaska) to preserve U.S. sovereignty over public and acquired lands and to preserve State sovereignty and private property rights in non-Federal lands surrounding those public and acquired lands.
H.R. 888	(Kildee) to limit the concentration of sulfur in gasoline used in motor vehicles.
H.R. 930	(Mink) to amend the Radiation Exposure Compensation Act to remove the requirement that exposure resulting in stomach cancer occur before age 30.
H.R. 933	(Morella) to ensure that coverage of bone mass measurements is provided under the health benefits program for Federal employees.
H.R. 965	(Quinn) to provide that December 7 each year be treated for all purposes related to Federal employment in the same manner as November 11.
H.R. 971	(Walsh) to amend the Public Utility Regulatory Policies Act of 1978 to ensure that rates charged by qualifying small power producers and qualifying cogenerators do not exceed the incremental cost to the purchasing utility of alternative electric energy at the time of delivery.
H.R. 993	(Duncan) to provide that of amounts available to a designated agency for a fiscal year but not obligated in the fiscal year, up to 50 percent may be used to pay bonuses to agency personnel and the remainder shall be deposited into the general fund of the Treasury and used exclusively for deficit reduction.
H.R. 1001	(Hulshof) to repeal the 4.3-cent motor fuel excise taxes on railroads and inland waterway transportation.
H.R. 1002	(Hunter) to require that all Government condemnations of property proceed under the Declaration of Taking Act.
H.R. 1031	(Hastings) to protect the White bluffs, located on the Columbia River in the State of Washington.

H.R. 1036	(Capps) to cease mineral leasing activity on submerged land of the Outer Continental Shelf adjacent to a coastal State that has declared a moratorium on this activity.
H.R. 1045	(Udall) to amend the Radiation Exposure Compensation Act to provide for partial restitution to individuals who work in uranium mines, mills, or transport that provided uranium for the use and benefit of the U.S. Government.
H.R. 1074	(Bliley) to provide Government-wide accounting of regulatory costs and benefits.
H.R. 1108	(Collins) to amend the Internal Revenue Code of 1986 to encourage the production and use of electric vehicles.
H.R. 1110	(Saxton) to reauthorize and amend the Coastal Zone Management Act of 1972.
H.R. 1111	(Morella) to establish a program under which long-term care insurance is made available to Federal employees and annuitants.
H.R. 1116	(Moran of Kansas) to promote domestic oil and gas production and provide a response to increasing oil imports (companion to Domenici bill).
H.R. 1117	(Moran of Kansas) to provide relief from certain interest and penalties on refunds ordered by FERC.
H.R. 1127	(McCrery) to exclude income from the transportation of oil and gas by pipeline from subpart F income.
H.R. 1138	(Stearns) to repeal section 210 of the Public Utility Regulatory Policies Act of 1978.
H.R. 1170	(Sabo) to make available, under the health benefits program for Federal employees, the option of obtaining coverage for self and children only.
H.R. 1204	(Stenholm) to impose a tax on the importation of crude oil and petroleum products.
H.R. 1205	(Stupak) to prohibit oil and gas drilling in the Great Lakes.
H.R. 1208	(Vento) to require in each subcontract under a Federal contract clauses that set forth a prompt payment policy and outline the provisions of the prompt payment statute and other related information.
H.R. 1210	(Vento) to provide continued compensation for Federal employees when funds are

not otherwise available due to a lapse in appropriations.

H.R. 1219 (Maloney) to amend Federal procurement law related to payment protections for persons furnishing labor and materials for Federal construction projects.

H.R. 1227 (Evans) to provide for the debarment or suspension from Federal procurement and non-procurement activities of persons who violate certain labor and safety laws.

H.R. 1253 (English) to restrict the use of tax-exempt financing by governmentally owned electric utilities and tax certain income-related activities of these utilities.

H.R. 1263 (Hoekstra) to require the Federal Government to disclose on each Federal employees paycheck the Government's share of taxes for old-age, survivor, disability, and hospital insurance for the employee, and the Government's total payroll allocation for the employee.

H.R. 1269 (George Miller of California) to strengthen sanctions for violations of the Federal Oil and Gas Royalty Management Act of 1982.

H.R. 1300 (Boehlert) to reauthorize and amend the Superfund program.

H.R. 1309 (Cook) to authorize the Secretary of Energy to provide compensation and increased safety for on-site storage of spent nuclear fuel and high-level radioactive waste.

H.R. 1348 (Ryun of Kansas) to establish a moratorium on the Foreign Visitors Program at the Department of Energy nuclear laboratories and establish a counter-intelligence program at each of those laboratories.

H.R. 1358 (Thomas) to provide tax credits for making energy efficiency improvements to existing homes and for constructing new energy efficient homes.

H. Con. Res. 74 (Markey) to express the sense of Congress regarding maintenance of the nuclear weapons stockpile.

H.R. 1367 (Franks of New Jersey) to prohibit the use of the fuel additive MTBE in gasoline.

H.R. 1398 (Pombo) to amend the Clean Air Act to prohibit the use of certain fuel additives.

H.R. 1416 (McCrery) to provide that for tax purposes interest on indebtedness used to finance the sale of rate-regulated electric energy or natural gas in the U.S. shall be allocated solely to sources within the U.S.

H.R. 1457 (Minge) to extend the tax credit for producing electricity from certain renewable resources.

H.R. 1465 (Salman) to allow a tax credit for residential solar energy property.

H.R. 1477 (Menendez) to withhold voluntary proportional assistance for programs and projects of the International Atomic Energy Agency relating to the development and completion of Bushehr nuclear power plant in Iran.

H.R. 1486 (Franks of New Jersey) to provide for a transition to market-based rates for power sold by the Federal Power Marketing Administrations and the Tennessee Valley

H.R. 1502 (Barcia) to minimize the disruption of Government and private sector operations caused by the Year 2000 computer problem.

H.R. 1513 (Norton) to allow Federal employees to take advantage of the transportation fringe benefit provisions of the Internal Revenue Code that are available to private sector employees.

H.R. 1516 (Skeen) to amend the Radiation Exposure Compensation Act to provide for payment of compensation to individuals exposed to radiation as the result of working in uranium mines and mills that provided uranium for the use of the U.S. Government.

H.R. 1548 (Traficant) to provide for a three-judge division of the court to determine whether cases alleging breach of secret Government contracts should be tried in court.

H.R. 1555 (Goss) to authorize appropriations for fiscal year 2000 for intelligence and intelligence-related activities of the U.S. Government.

H.R. 1559 (Cannon) to amend the Uranium Mill Tailings Radiation Control Act of 1978 to proved for the remediation of the Atlas mill tailings site near Moab, Utah.

H.R. 1572 (Gordon) to require the adoption and use of digital signatures by Federal agencies.

H.R. 1587 (Stearns) to encourage States to establish competitive retail markets for electricity, clarify the roles of the Federal Government and the States in retail electricity markets, and remove certain Federal barriers to competition.

H.R. 1600	(Fattah) to proved that Federal contracts and certain Federal subsidies be provided only to businesses that have qualified profit-sharing plans.
H.R. 1606	(Kanjorski) to make certain temporary Federal service creditable for retirement purposes.
H.R. 1655	(Calvert) to authorize appropriations for fiscal years 2000 and 2001 for the civilian energy and scientific research, development, and demonstration and related commercial application of DOE energy technology programs.
H.R. 1656	(Calvert) to authorize appropriations for fiscal years 2000 and 2001 for the commercial application of energy technology and related DOE civilian energy and scientific programs.
H.R. 1682	(Mrs. Wilson) to establish a permanent tax incentive for research and development.
H.R. 1700	(Hostettler) to provide that a national missile defense system not be required to complete initial operational evaluations before proceeding beyond low-rate initial production and provide that an environmental impact statement prepared for the construction of any element of such a system not be subject to judicial review.
H.R. 1705	(Pallone) to amend the Clean Air Act to waive the oxygen content requirement for reformulated gasoline and to phase out the use of MTBE.
H.R. 1731	(Herger) to apply the tax credit for electricity produced from certain renewable resources to electricity produced from biomass facilities and to extend the placed-in-service deadline for this credit.
H.R. 1753	(Doyle) to promote the research, identification, assessment, exploration, and development of methane hydrate resources.
H.R. 1759	(Hastings) to ensure the long-term protection of the resources of the portion of the Columbia River known as the Hanford Reach.
H.R. 1769	(Cummings) to eliminate certain inequities in the Civil Service Retirement System and the Federal Employees Retirement System with respect to the computation of benefits for law enforcement officers, firefighters, air traffic controllers, nuclear materials couriers, and their survivors.
H.R. 1770	(Cummings) to revise the overtime pay limitation for Federal employees.

H.R. 1827	(Burton of Indiana) to require Federal agencies to use recovery audits.
H.R. 1828	(Bliley–by request) to provide for a more competitive electric power industry (the Administration's electricity industry restructuring legislation).
H.R. 1835	(Gilman) to impose conditions on assistance, nuclear cooperation, and other transactions with North Korea.
H.R. 1884	(Ford) to provide for the disclosure of the readiness of certain Federal and non-Federal computer systems for the Y2K problem.
H.R. 1924	(Gekas) to prevent Federal agencies from unjustifiably ignoring and relitigating precedents established by Federal courts.
H.R. 1971	(Watkins) to amend the Internal Revenue Code of 1986 to encourage domestic oil and gas production.
H.R. 1985	(Cubin) to improve the administration of oil and gas leases on Federal land.
H.R. 1991	(Johnson of Texas) to amend the Internal Revenue Code of 1986 to clarify that natural gas gathering lines are seven-year property for purposes of depreciation.
H.R. 1992	(Klink) to maintain Federal average fuel economy standards applicable to automobiles in effect at current levels until changed by law.
H.R. 2022	(McIntosh) to prohibit compliance by the executive branch with the 1972 Anti-Ballistic Missile Treaty and the 1997 Memorandum of Understanding related to the treaty.
H.R. 2023	(McIntosh) to schedule production of elements for a national missile defense system.
H.R. 2029	(Radanovich) to amend the National Environmental Policy Act of 1969 to require Federal agencies to consult with State agencies and county and local governments on environmental impact statements.
H.R. 2032	(Thornberry) to establish in the Department of Energy a Nuclear Security Administration and an Office of Under Secretary for National Security.
H.R. 2038	(Weller) to amend the Internal Revenue Code of 1986 with respect to deductions for decommissioning costs of nuclear powerplants.
H.R. 2050	(Largent) to provide consumers with a reliable source of electricity and a choice of electric providers.

H.R. 2052	(DeFazio) to provide Oregon with a role in making decisions on environmental restoration and waste management at the Hanford Reservation.
H.R. 2086	(Sensenbrenner) to authorize funding for networking and information technology research and development for fiscal years 2000 through 2004.
H.R. 2088	(Hayworth) to prohibit discrimination in contracting federally funded projects on the basis of certain labor policies of potential contractors.
H.R. 2096	(Engle) to provide Federal employees the option of obtaining health benefits coverage for dependent parents.
H.R. 2128	(Brady of Texas) to provide for periodic review of the efficiency and public need for Federal agencies, to establish a commission to review the efficiency and public need for Federal agencies, and provide for the abolishment of agencies for which a public need does not exist.
H.R. 2179	(Udall of Colorado) to provide for the management as open space of certain lands at the Rocky flats Environmental Technology Site.
H.R. 2221	(McIntosh) to prohibit the use of Federal funds to implement the Kyoto Protocol on Climate Change until the Senate has ratified it and to clarify the authority of Federal agencies to regulate emissions of carbon dioxide.
H.R. 2250	(Young of Alaska) to establish an oil and gas leasing program for the exploration, development, and production of the oil and gas resources of the Coastal Plain.
H.R. 2252	(Camp) to provide increased tax incentives for the purchase of alternative fuel and electric vehicles.
H.R. 2335	(Towns) to improve the hydroelectric licensing process by granting FERC statutory authority to improve coordination of other agency and entity participation.
H.R. 2363	(Tauzin) to repeal the Public Utility Holding Company Act of 1935 and enact the Public Utility Holding Company Act of 1999.
H.R. 2368	(Young of Alaska) to assist in the resettlement of the people of Bikini Atoll by amending the terms of the trust fund established during the U.S. administration of the Trust Territory of the Pacific Islands.
H.R. 2372	(Canady of Florida) to simplify access to the Federal courts for parties deprived of their constitutional rights by final Federal agency action and improve procedures

in other instances of claims arising under the Constitution.

H.R. 2376 (Green) to require an executive agency to establish expedited review procedures for granting a waiver to a State under a grant program if another State has been granted a similar waiver under the program.

H.R. 2380 (Matsui) to provide tax incentives to reduce energy consumption.

H.R. 2411 (Boyce) to abolish the Department of Energy.

H.R. 2420 (Tauzin) to deregulate the Internet and high speed data services.

H.R. 2429 (Crane) to amend the Internal Revenue Code of 1986 to establish a five-year recovery period for petroleum storage facilities.

H.R. 2449 (Norwood) to amend the Federal Water Pollution Control Act relating to Federal facilities pollution control.

H.R. 2456 (Simpson) to preserve State authority over waters within State boundaries and to delegate the authority of Congress to regulate water to States.

H.R. 2464 (Watkins) to provide that for Federal tax purposes certain amounts received by electric energy, gas, or steam utilities be excluded from gross income as contributions to capital.

H.R. 2520 (Lazio) to provide regulatory credit for voluntary early mitigation of potential environmental impacts from greenhouse gas emissions.

H.R. 2556 (Wolf) to require the Secretary of Transportation, through the Congestion Mitigation and Air Quality Program, to develop a program for reducing emissions of air pollutants.

H.R. 2569 (Pallone) to encourage State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency.

H.R. 2600 (Wu) to reduce the level of long-range nuclear forces of the Department of Defense to 3,500 warheads consistent with the START II Treaty.

H.R. 2602 (Wynn) to amend the Federal Power Act with respect to electric reliability and oversight.

H.R. 2603 (Wu) to eliminate the use of the Savannah River nuclear waste separation facilities.

H.R. 2604	(Wu) to terminate the funding for the Fast Flux Test Facility at the Hanford Nuclear Reservation.
H.R. 2631	(Davis of Virginia) to modify employee contributions to the Civil Service Retirement System and the Federal Employees Retirement System to the percentages in effect before the statutory temporary increase in calendar year 1999.
H.R. 2641	(Cubin) to make technical corrections to title X of the Energy Policy Act of 1992.
H.R. 2644	(Hinchey) to prohibit, except in limited circumstances, Federal, State, and local agencies and private entities from transferring, selling, or disclosing personal data with respect to an individual to other agencies or entities without the express consent of the individual.
H.R. 2645	(Kucinich) to provide for the restructuring of the electric power industry.
H.R. 2667	(Allen) to amend the Clean Air Act to establish requirement concerning the operation of fossil fuel-fired electric utility steam generating units, commercial and industrial boiler units, solid waste incineration unites, and other combustion and incineration units.
H.R. 2696	(Davis of Virginia) to provide for more equitable policies relating to overtime pay for Federal employees and the accumulation and use of credit hours.
H.R. 2733	(Bliley) to allow Federal agencies to reimburse their employees for certain adoption expenses.
H.R. 2734	(Brown of Ohio) to allow local governmental entities to serve as nonprofit aggregators of electricity services on behalf of their citizens.
H.R. 2754	(Gillmor) to limit the portion of the Superfund that is expended for administration, oversight, support, studies, investigations, monitoring, assessment, evaluation, and enforcement activities.
H.R. 2786	(Sawyer) to provide for expansion of electricity transmission networks.
H.R. 2819	(Udall) to create an initiative for research and development into the use of biomass for fuel and industrial products.
H.R. 2823	(Cannon) to provide for the retention and administration of Oil Shale Reserve Numbered 2 by the Secretary of Energy.

H.R. 2842	(Cummings) to enable the Federal Government to enroll an employee and family in the FEHB Program when a State court orders the employee to provide health insurance coverage for a child of the employee but the employee fails to provide the coverage.
H.R. 2844	(Istook) to direct the Secretary of Energy to convey to Bartlesville, Oklahoma, the former site of the NIPER facility.
H.R. 2859	(Frank) to provide benefits to domestic partners of Federal employees.
H.R. 2884	(Bliley) to extend energy conservation programs under the Energy Policy and Conservation Act through fiscal year 2003.
H.R. 2885	(Horn) to provide uniform safeguards for the confidentiality of information acquired for exclusively statistical purposes and to improve the efficiency and quality of Federal statistics and Federal statistical programs.
H.R. 2887	(Baker) to amend the Federal Power Act to ensure that certain Federal power customers are provided protection by the Federal Energy Regulatory Commission.
H.R. 2900	(Waxman) to reduce the emissions from electric powerplants.
H.R. 2940	(Stupak) to amend the Superfund law to provide liability relief for small parties, innocent landowners, and prospective purchasers.
H.R. 2944	(Barton) to promote competition in electricity markets and provide consumers with a reliable source of electricity.
H.R. 2947	(Inslee) to provide for use of net metering by certain small electric energy generation systems.
H.R. 2956	(Pallone) to reauthorize the Superfund Act.
H.R. 2978	(Bliley) to extend energy conservation programs under the Energy Policy and Conservation Act through October 31, 1999.
H.R. 2980	(Allen) to reduce emissions of mercury, carbon dioxide, nitrogen oxides, and sulfur dioxide from fossil fuel-fired electric utility generating units in the U.S.
H.R. 2981	(Bliley) to extend energy conservation programs under the Energy Policy and Conservation Act through March 31, 2000.
H.R. 2985	(Bono) to provide for a biennial budget process and biennial appropriations

process and enhance oversight and efficiency of the Federal Government.

H.R. 3111	(Hyde) to exempt certain reports from automatic elimination and sunset pursuant to the Federal Reports Elimination and Sunset Act of 1995.
H.R. 3137	(Horn) to provide for training individuals a President-elect intends to nominate as department heads or appoint to key positions in the Executive Office of the President.
H.R. 3147	(Davis of Virginia) to alleviate the pay-compression problem affecting members of the Senior executive service and other senior-level Federal employees.
H.R. 3151	(Strickland) to provide funding for the Portsmouth and Paducah gaseous diffusion plants.
H.R. 3152	(Goss) to provide for the identification, collection, and review for declassification of records and materials that are of extraordinary public interest.
H.R. 3160	(Young) to reauthorize and amend the Endangered Species Act.
H.R. 3234	(Goodling) to exempt certain reports from automatic elimination and sunset under the Federal Reports and Elimination and sunset Act of 1995.
H.R. 3307	(Chabot) to require Federal agencies to conduct an assessment of the privacy implications resulting from a proposed rule.
H.R. 3311	(Gekas) to provide for the analysis of the costs and benefits of major rules.
H.R. 3312	(Gekas) to establish a pilot program that to provide a voluntary alternative dispute resolution process to assist Federal agencies and employees in resolving certain personnel actions and disputes in administrative programs.
H.R. 3383	(Barton) to amend the Atomic Energy Act of 1954 to remove separate treatment or exemption for nuclear safety violations by nonprofit institutions.
H.R. 3384	(Barton) to strengthen provisions in the Energy Policy Act of 1992 with respect to potential climate change.
H.R. 3385	(Barton) to strengthen provisions in the Federal Nonnuclear Energy Research and Development Act of 1974 with respect to potential climate change.
H.R. 3418	(Kanjorski) to establish a compensation program for DOE federal, contractor, and

subcontractor employees and employees of DOE beryllium vendors who sustain beryllium related illness due to the performance of their duty and for certain workers at the Paducah gaseous diffusion plant and establish a pilot program for examining the possible relationship between workplace exposure to radiation and illnesses among certain workers at Oak Ridge.

H.R. 3447 (Hastings) to provide for the sale of electricity by BPA to joint operating entities.

H.R. 3449 (Greenwood) to amend the Clean Air Act to provide for a State waiver of the requirements concerning the oxygen content of gasoline.

H.R. 3464 (Boswell) to establish a cooperative program of the Department of Agriculture, DOE, and EPA to evaluate the feasibility of using only fuel blended with ethanol to power municipal vehicles.

H.R. 3466 (Camp) to expand the tax credit for electricity produced from certain renewable resources to include energy produced from landfill gas.

H.R. 3478 (Kaptur) to establish a compensation program for the contractors of the Departments of Defense and Energy and beryllium vendors who sustained a beryllium-related illness due to the performance of their duty.

H.R. 3495 (Strickland) to establish a compensation program for DOE employees injured in Federal nuclear activities.

H.R. 3502 (Udall of New Mexico) to enhance the ability of the National Laboratories to meet DOE missions.

H.R. 3506 (Weldon) to provide that in certain cases the parent corporation of a Federal contractor provides health care benefits to retired contractor employees if the contractor fails to provide the benefits.

H. Res. 369 (Kucinich) to reduce the risks and dangers associated with nuclear weapons in the new millennium.

H.R. 3533 (Ackerman) to provide the Secretary of Energy authority to draw down the SPR when U.S. oil and gas prices rise sharply because of anti-competitive activity and require the President, through the Secretary of Energy, to consult with Congress regarding sale of SPR oil.

H.R. 3536 (Franks) to require the study of potential health effects of ingesting and inhaling MTBE, research on methods for removing MTBE from water supplies, and monitoring public water systems for MTBE.

H.R. 3543 (Larson) to provide the Secretary of Energy authority to draw down the SPR when U.S. oil and gas prices rise sharply because of anti-competitive activity and require the President, through the Secretary of Energy, to consult with Congress regarding sale of SPR oil.

H.R. 3564 (Isakson) to include within the President's annual budget submission three percent cuts in the budget of each department or agency of the Government.

H.R. 3586 (Callahan) to provide for a biennial budget process and a biennial appropriations process.

H.R. 3603 (Wolf) to expand Federal employee commuting options and to reduce the traffic congestion resulting from current Federal employee commuting patterns.

H.R. 3608 (Sanders) to provide the Secretary of Energy with authority to create a Fuel Oil Product Reserve to be available for use when fuel oil prices in the U.S. rise sharply because of anti-competitive activity, during a fuel oil shortage, or during periods of extreme winter weather.

H.R. 3641 (Sweeney) to require the Secretary of Energy to study causes of the recent home heating fuel price spikes in the Northeast and to create a 10,000,000 barrel heating oil reserve in the Northeast.

H.R. 3644 (Weygand) to authorize drawdown and distribution from the SPR in the case of severe emergency supply interruptions on a State or regional level.

H.R. 3662 (McGovern) to require the Secretary of Energy to report to Congress on the readiness of the heating oil and propane industries.

H.R. 3669 (Mrs. Kelly) to establish a five-year pilot project for the GAO to report to Congress on economically significant rules of Federal agencies.

H.R. 3711 (Hastings) to impose a one-year moratorium on certain diesel fuel excise taxes.

H.R. 3749 (Ramstad) to reduce temporarily the rates of tax on highway gasoline, diesel fuel, and kerosene by ten cents per gallon.

H.R. 3766 (Wynn) to improve the efficiency of the Federal Government.

H. Con. Res. 256 (Ewing) expressing the sense of Congress with regard to the use of reformulated gasoline fuels.

Senate:

S. 22 (Moynihan) to provide a system to classify information in the interests of national security and a system to declassify information.

S. 36 (Grassley) to provide long-term care insurance for Federal employees.

S. 45 (Helms) to prohibit the executive branch from establishing an additional class of individuals who are protected against discrimination in Federal employment.

S. 57 (Mikulski) to provide long-term care insurance for Federal employees and annuitants (Administration bill, companion to H.R. 110).

S. 59 (Thompson) to provide a Government-wide accounting for regulatory costs and benefits.

S. 92 (Domenici) to provide for a biennial budget process and a biennial appropriations process and to enhance oversight and the performance of the Federal Government.

S. 93 (Domenici) to improve and strengthen the budget process.

S. 99 (McCain) to provide for continuing Government operations in the absence of regular appropriations for fiscal year 2000.

S. 100 (McCain) to grant the President power to reduce budget authority.

S. 104 (Grams) to provide for continuing appropriations in the absence of regular appropriations.

S. 125 (Feingold) to reduce the number of executive branch political appointees.

S. 139 (Robb) to grant the President power to reduce budget authority.

S. 147 (Abraham) to maintain Federal corporate average fuel economy standards for automobiles in effect at current levels.

S. 161 (Moynihan) to provide for a transition to market-based rates for power sold by the Federal Power Marketing Administrations and the Tennessee Valley Authority.

S. 162 (Breaux) to change the calculation of the 50,000-barrel refinery limitation on oil depletion tax deduction from a daily basis to an annual average daily basis.

S. 171 (Moynihan) to amend the Clean Air Act to limit the concentration of sulfur in gasoline used in motor vehicles.

S. 172 (Moynihan) to reduce acid deposition under the Clean Air Act.

S. 195 (Boxer) to extend the research tax credit permanently.

S. 205 (Moynihan) to establish a Federal Commission on Statistical Policy to study reorganizing the Federal statistical system, provide uniform safeguards for the confidentiality of certain information, and improve the quality of Federal statistics.

S. 246 (Hagel) to require Federal agencies to prepare private property taking impact analyses and expand access to Federal courts for private property cases.

S. 257 (Cochran) to state U.S. policy regarding the deployment of a missile defense capable of defending U.S. territory against limited ballistic missile attack. (Cochran also introduced another bill, S. 269, with the same title.)

S. 266 (Feinstein) to amend the Clean Air Act to permit the exclusive application of California regulations regarding reformulated gasoline in certain areas within the State.

S. 267 (Feinstein) to direct EPA to give highest priority to petroleum contaminants in drinking water in issuing corrective action orders under the Solid Waste Disposal Act response program for petroleum.

S. 282 (Mack) to prohibit electric utilities from being required to enter into a new contract or obligation to purchase or to sell electricity or capacity under section 210 of the Public Utility Regulatory Policies Act of 1978.

S. 296 (Frist) to increase funding for Federal research and development.

S. 313 (Shelby) to repeal the Public Utility Holding Company Act of 1935 and enact the Public Utility Holding Company Act of 1999.

S. 325 (Hutchison) to provide tax incentives to encourage U.S. production of oil and gas.

S. 330 (Akaka) to promote the research, exploration, and development of methane hydrate resources for long-term energy supply needs.

S. 334	(Akaka) to repeal FERC's authority to license projects on the fresh waters of Hawaii.
S. 348	(Snowe) to assist the oilheat industry.
S. 352	(Thomas) to require Federal agencies to consult with State agencies and local governments on environmental impact statements.
S. 358	(Grams) to freeze Federal discretionary spending at fiscal year 2000 levels, to extend the discretionary budget caps until 2010, and to require a two-thirds vote of the Senate to breach the budget caps.
S. 367	(Bingaman) to amend the Radiation Exposure Compensation Act to provide partial restitution to individuals who worked in uranium mines, mills, or transport that provided uranium for U.S. use.
S. 386	(Gorton) to provide for tax-exempt bond financing of certain electric facilities.
S. 397	(Bingaman) to authorize the Secretary of Energy to establish a multi-agency program to promote energy efficient economic development along the border with Mexico through the research, development, and use of new materials. (companion to H.R. 666)
S. 414	(Grassley) to provide a five-year extension of the tax credit for producing electricity from wind. (companion to H.R. 750)
S. 422	(Murkowski) to provide for Alaska jurisdiction over small hydroelectric projects.
S. 427	(Abraham) to provide more information for congressional deliberation on private sector mandates.
S. 468	(Voinvich) to improve the performance of Federal financial assistance programs and simplify Federal financial assistance application and reporting requirements.
S. 510	(Campbell) to preserve U.S. sovereignty over public and acquired lands and to preserve State sovereignty and private property rights in non-Federal lands surrounding those public and acquired lands.
S. 516	(Thomas) to promote competition in the electric power industry.

S. 547 (Chafee) to authorize the President to enter into agreements to provide regulatory credit for voluntary early action to mitigate potential environmental impacts from greenhouse gas emissions.

S. 557 (Thompson) to provide guidance for the designation of emergencies as a part of the budget process.

S. 558 (Thompson) to prevent the shutdown of the Government at the beginning of a fiscal year if a new budget has not been enacted.

S. 595 (Domenici) to promote domestic oil and gas production and provide a response to increasing oil imports.

S. 608 (Murkowski) to amend the Nuclear Waste Policy Act of 1982 and establish an interim storage facility for nuclear waste.

S. 618 (Moynihan) to declassify the journal kept by Glenn T. Seaborg while serving as chairman of the Atomic Energy Commission.

S. 626 (Roberts) to provide that rate refunds FERC orders in connection with certain sales of natural gas not include interest or penalty.

S. 645 (Feinstein) to amend the Clean Air Act to waive the oxygen content requirement for reformulated gasoline in certain instances

S. 650 (Wellstone) to amend the Occupational Safety and Health Act of 1970 to cover Federal Government employees.

S. 673 (Leahy) to establish requirements concerning the operation of electric utility steam generating units fired by fossil fuels, commercial and industrial boiler units, solid waste incineration units, and other facilities to reduce emissions of mercury to the environment.

S. 680 (Hatch) to extend permanently the research tax credit.

S. 683 (Bryan) to amend the Nuclear Waste Policy Act of 1982 to give credits to commercial nuclear utilities to offset the costs of storing spent fuel DOE is unable to accept for disposal.

S. 685 (Crapo) to preserve States' authority over water within their boundaries and to delegate to States the authority of congress to regulate water.

S. 715 (Murray) to designate a portion of the Columbia River as a recreational river.

S. 723 (Inhofe) to provide regulatory amnesty for defendants who are unable to comply with Federal requirements because of factors related to a Y2K system failure.

S. 740 (Craig) to improve FERC's authority to coordinate participation by other agencies and entities in the hydroelectric licensing process.

S. 746 (Levin) to provide for analysis of major rules, to publicize the costs and benefits of major rules, and to increase the accountability and quality of Government.

S. 804 (Rockefeller) to improve the ability of Federal agencies to license Federally-owned inventions.

S. 815 (Roth) to extend the tax credit for producing electricity from certain renewable resources.

S. 826 (Thomas) to limit U.S. acquisition of land in a State 25 percent or more of whose land is owned by the U.S.

S. 834 (Campbell) to withhold voluntary proportional assistance for programs and projects of the International Atomic Energy Agency relating to the development and completion of Bushehr nuclear power plant in Iran.

S. 851 (Chafee) to allow Federal employees to take advantage of the transportation fringe benefit provisions of the Internal Revenue Code that are available to private sector employees.

S. 882 (Murkowski) to amend EPAct and the Federal Nonnuclear Act with respect to potential climate change.

S. 887 (Shelby) to establish a moratorium on the Foreign Visitors Program at DOE nuclear labs.

S. 894 (Cleland) to establish a program under which long-term care insurance is made available to Federal employees and annuitants.

S. 896 (Grams) to abolish the Department of Energy.

S. 897	(Baucus) to provide matching grants for the construction, renovation, and repair of school facilities in areas affected by Federal activities.
S. 932	(Campbell) to prevent Federal agencies from not following and re-litigating unjustifiably precedents established in the Federal courts.
S. 951	(Domenici) to establish a permanent tax incentive for research and development.
S. 974	(Warner) to authorize appropriations for fiscal years 2000 and 2001 for military activities of the Department of Defense.
S. 984	(Collins) to modify the tax credit for electricity produced from certain renewable resources.
S. 999	(Hatch) to improve the ability of Federal agencies to patent and license federally owned inventions.
S. 1003	(Rockefeller) to provide increased tax incentives for the purchase of alternative fuel and electric vehicles.
S. 1009	(Shelby) to authorize appropriations for fiscal year 2000 for intelligence and intelligence-related activities of the United States Government.
S. 1028	(Hatch) to expedite access to the Federal courts for injured parties deprived of their Constitutional rights by final Federal agency action.
S. 1040	(Shelby) to reduce the power of the Federal establishment.
S. 1042	(Hutchinson) to amend the Internal Revenue Code of 1986 to encourage domestic oil and gas production.
S. 1047	(Murkowski–by request) to provide for a more competitive electric power industry (the Administration's electricity restructuring bill).
S. 1048	(Murkowski–by request) tax provisions of the Administration's electricity industry restructuring legislation.
S. 1049	(Murkowski) to improve the administration of oil and gas leases on Federal land.
S. 1050	(Murkowski) to provide tax incentives for gas and oil producers.
S. 1051	(Murkowski–by request) to amend the Energy Policy and Conservation Act to manage the Strategic Petroleum Reserve more effectively.

S. 1071 (Crapo) to designate the Idaho National Engineering and Environmental Laboratory as the Center of Excellence for Environmental Stewardship of Department of Energy Land and establish within the Center the Natural Resources Institute.

S. 1090 (Chafee) to reauthorize and amend the Comprehensive Environmental Response, Liability, and Compensation Act of 1980 (Superfund).

S. 1095 (Conrad) to amend the Internal Revenue Code of 1986 to extend the placed in service date for biomass and coal facilities.

S. 1116 (Nickles) to amend the Internal Revenue Code of 1986 to exclude income from the transportation of oil or gas by pipeline from subpart F income .

S. 1157 (Smith of New Hampshire) to repeal the Davis-Bacon Act.

S. 1166 (Nickles) to amend the Internal Revenue Code of 1986 to clarify that natural gas gathering lines are seven-year property for purposes of depreciation.

S. 1167 (Gorton) to amend the Pacific Northwest Electric Power Planning and Conservation Act to expand the scope of the Independent Scientific Review Panel.

S. 1183 (Nickles) to direct the Secretary of Energy to convey the former site of the DOE NIPER facility to the city of Bartlesville, Oklahoma.

S. 1194 (Hutchinson) to prohibit discrimination in contracting federally funded projects on the basis of certain labor policies of potential contractors.

S. 1198 (Shelby) to provide for a General Accounting Office report on agency regulatory actions.

S. 1214 (Thompson) to require each Federal agency to appoint a federalism officer who shall monitor agency rules for their adverse effect on federalism.

S. 1226 (Mack) to amend the Internal Revenue Code of 1986 to provide that interest on indebtedness used to finance the provision or sale of rate-regulated electric energy or natural gas in the U.S. be allocated only to sources within the U.S.

S. 1230 (Boxer) to amend the Internal Revenue Code of 1986 to encourage the production and use of clean-fuel vehicles.

S. 1260 (Hatch) to make technical corrections to the Copyright Act.

S. 1273 (Bingaman) to facilitate the transition to more competitive and efficient electric power markets.

S. 1280 (Boxer) to terminate the exemption of certain contractors and other entities from civil penalties for violation of nuclear safety requirements under the Atomic Energy Act of 1954.

S. 1284 (Nickles) to ensure that a State may not establish, maintain, or enforce an exclusive right to sell electric energy on behalf of any electric utility or may not otherwise unduly discriminate against a consumer seeking to purchase electric energy in interstate commerce from a supplier.

S. 1287 (Murkowski) to provide for the storage of spent nuclear fuel pending completion of the nuclear waste repository.

S. 1298 (Warner) to provide for professional liability insurance coverage for Federal employees.

S. 1301 (Stevens) to provide reasonable access to buildings owned or used by the Federal government if the access is to provide competitive telecommunications services by telecommunications carriers.

S. 1308 (Murkowski) to amend the Internal Revenue Code of 1986 with respect to deductions for decommissioning costs of nuclear power plants.

S. 1323 (McConnell) to amend the Federal Power Act to ensure that TVA's Federal power customers are provided protection by FERC.

S. 1334 (Akaka) to increase the amount of leave time available to a Federal employee in connection with serving as an organ donor.

S. 1339 (Durbin) to debar or suspend from Federal procurement and other activities persons who violate certain labor and safety laws.

S. 1351 (Grassley) to extend and modify the tax credit for electricity produced from renewable resources.

S. 1352 (Helms) to impose conditions on assistance for North Korea and restrict nuclear cooperation and other transactions with North Korea.

S. 1369 (Jeffords) to encourage State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency.

S. 1378	(Voinovich) to facilitate compliance by small businesses with Federal paperwork requirements.
S. 1381	(Cochran) to establish a 5-year recovery period for petroleum storage facilities.
S. 1411	(Stevens) to extend the tax credit for producing electricity from certain renewable resources.
S. 1425	(Specter) to allow a 10 percent biotechnology investment tax credit and to reauthorize the research and development tax credit.
S. 1429	(Roth) to provide for budget reconciliation.
S. 1437	(Moynihan) to prevent researchers from compelled disclosure of research in Federal courts.
S. 1439	(Feingold) to terminate production under the D5 submarine-launched ballistic missile program.
S. 1441	(Sarbanes) to modify employee contributions to the Civil Service Retirement System and the Federal Employees Retirement System to the percentages in effect before the statutory temporary increase in calendar year 1999.
S. 1472	(Sarbanes) to modify employee contributions to the Civil Service Retirement System and the Federal Employees Retirement System to the percentages in effect before the statutory temporary increase in calendar year 1999. (companion to H.R. 2631)
S. 1483	(Reid) to amend the National Defense Authorization Act for fiscal Year 1998 with respect to export controls on high performance computers.
S. 1515	(Hatch) to amend the Radiation Exposure Compensation Act.
S. 1534	(Snowe) to reauthorize the Coastal Zone Management Act.
S. 1537	(Chafee) to reauthorize and amend the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (Superfund).
S.J. Res. 31	(Allard) proposing an amendment to the Constitution granting the President line-item veto power.

S. 1561 (Bennett) to provide for the retention and administration of Oil Shale Reserve Numbered 2 by the Secretary of Energy. (Companion to H.R. 2823)

S.1634 (Allard) to allow a tax credit for residential solar energy property.

S. 1636 (Feingold) to authorize a new trade, investment, and development policy for sub-Saharan Africa.

S. 1756 (Bingaman) to enhance the ability of the National Laboratories to meet Department of Energy missions.

S. 1770 (Lott) to extend permanently the research and development credit and extend certain other expiring provisions of the Internal Revenue Code of 1986 for 30 months.

S. 1776 (Craig) to amend the Energy Policy Act of 1992 to revise U.S. energy policy, reduce greenhouse gas emissions, advance global climate science, promote technology development, and increase citizen awareness.

S. 1777 (Craig) to provide tax incentives for the voluntary reduction of greenhouse gas emissions and advance global climate science and technology development.

S. 1792 (Roth) to extend expiring tax provisions.

S. 1793 (Domenici) to ensure that there will be adequate funding for the decommissioning of nuclear power facilities.

S. 1798 (Hatch) to provide enhanced protection for investors and innovators, protect patent terms, and reduce patent litigation.

S. 1801 (Moynihan) to provide for the identification, collection, and review for declassification of records and materials that are of extraordinary public interest. (companion to H.R. 3152)

S. 1803 (Robb) to extend permanently and expand the research tax credit.

S. 1812 (Warner) to establish a commission on a nuclear testing treaty.

S. 1835 (Leahy) to restore Federal remedies for violations of intellectual property rights by States.

S. 1877 (Thompson) to amend the Federal Report Elimination and Sunset Act of 1995.

S. 1881	(Dodd) to make certain temporary Federal service creditable for retirement purposes.
S. 1885	(Robb) to provide for more equitable policies relating to overtime pay for Federal employees, limitations on premium pay, and the accumulation and use of credit hours.
S. 1886	(Inhofe) to waive the oxygen content requirement for reformulated gasoline, to encourage development of voluntary standards to prevent and control releases of methyl tertiary butyl ether from under ground storage tanks.
S. 1889	(Grams) to amend the Congressional Budget Act of 1974 to provide for joint resolutions on the budget, reserve funds for emergency spending, strengthen enforcement of budgetary decisions, increase accountability for Federal spending, and accomplish other goals.
S. 1937	(Craig) to provide for the sales of electricity by BPA to joint operating entities. (companion to H.R. 3447)
S. 1945	(Bond) to amend title 23, United States Code, to make renewable fuel projects eligible under the air quality improvement program.
S. 1949	(Leahy) to promote economically sound modernization of electric power generation capacity in the U.S.; improve the combustion efficiency of fossil fuel-fired electric utility generating units; to reduce emissions of contaminants; to require all U.S. fossil fuel-fired electric utility generating units to meet new source review requirements; to promote the use of clean coal technologies; and to promote alternative energy and clean energy sources.
S. 1951	(Schumer) to provide the Secretary of Energy with authority to draw down the SPR when oil and gas prices in the U.S. rise sharply because of anti-competitive activity and to require the President, through the Secretary of Energy, to consult with Congress regarding the sale of oil from the SPR.
S. 1954	(Bingaman) to establish a compensation program for DOE federal, contractor, and subcontractor employees and employees of DOE beryllium vendors who sustain beryllium related illness due to the performance of their duty and for certain workers at the Paducah gaseous diffusion plant and establish a pilot program for examining the possible relationship between workplace exposure to radiation and illnesses among certain workers at Oak Ridge. (companion to H.R. 3418)
S. 1959	(Harkin) to provide for the fiscal responsibility of the Federal Government.

S. 2046	(Frist) to reauthorize the Next Generation Internet Act.
S. 2047	(Dodd) to direct the Secretary of Energy to create a Heating Oil Reserve to be available for use when fuel oil prices in the U.S. rise sharply because of anti-competitive activity, during a fuel oil shortage, or during periods of extreme winter weather.
S. 2071	(Gorton) to promote the reliability of the bulk-power electric system.
S. 2072	(Kerry) to require the Secretary of Energy to report to Congress on the readiness of the heating oil and propane industries. (Companion to H.R. 3662).
S. 2075	(Robb) to expand Federal employee commuting options and to reduce the traffic congestion resulting from current Federal Employee commuting patterns. (Companion to H.R. 3603)
S. 2090	(Campbell) to impose a one-year moratorium on certain diesel fuel excise taxes.
S. 2094	(Kennedy) to insure that petroleum importers, refiners, and wholesalers accumulate minimally adequate supplies of home heating oil to meet reasonably foreseeable needs in the northeastern States.
S. 2098	(Murkowski) to facilitate the transition to more competitive and efficient electric power markets and to ensure electric reliability.
S. 2106	(Ashcroft) to increase internationally the exchange and availability of information regarding biotechnology and to coordinate a Federal strategy in order to advance the benefits of biotechnology.

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Transmission via Facsimile

OFFICE OF THE VICE PRESIDENT

Phone: (202) 456-9000 Fax: (202) 456-6212

Date: 4/2/01 Time: 6:00pm

To: Joseph T. Kelliher

Fax Number: 202-586-7210

From: Chris Covert - Energy Policy Taskforce Intern

Number of Pages, Including Cover Sheet: 9

Message: Mr. Kelliher
Here is the railroad information we spoke about as you were leaving the Thursday Working Groups meeting.

Chris C.

23550

DOE024-0956

ASSOCIATION OF AMERICAN RAILROADS
50 F STREET, N.W.
WASHINGTON, D.C. 20001

Edward R. Hamberger
President and Chief Executive Officer

Telephone: (202) 639-2400
Fax: (202) 639-2286

March 23, 2001

The Honorable Dick Cheney
The White House
Washington, DC 20500

Dear Mr. Vice President:

I am writing to you in your capacity as chairman of the White House Energy Policy Development Task Force. The Association of American Railroads (AAR) appreciates this opportunity to offer its observations on the impact of higher energy prices on the nation's rail sector.

I would note that AAR's comments are intended to supplement the briefing papers submitted to you earlier by the Coal-Based Generation Stakeholders group of which the railroads are leading members. Some 52 percent of our nation's electricity is generated by coal (with more than two-thirds of that coal transported by rail) and coal is one of the nation's least expensive sources of electrical energy.

In developing an effective energy strategy, it is important to remember that America -- at least until recently -- has enjoyed some of the lowest energy prices in the world. These low energy costs have enhanced our competitive position in all sectors of trade from agriculture to manufacturing.

Railroads applaud the Bush administration's efforts to develop a national energy strategy, and we commend you for personally taking on the responsibility for this effort. Energy improvements will contribute to the industry's bottom line due to both lower diesel fuel costs as well as their impact on railroad customers. These customers range from automobile manufacturers whose products can be affected by higher fuel prices to electric utility customers for whom railroads ship millions of tons of coal each year.

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Despite the fact that railroads are three times more fuel efficient than trucks, the price of diesel fuel continues to be a major challenge for the rail industry. In providing cost and energy efficient freight service, U.S. freight railroads consume huge volumes of diesel fuel -- over four billion gallons annually. Because the cost of fuel is a major cost component of railroad operations -- comprising 7.1 percent of industry costs -- the alarming jump in fuel prices over recent periods has been a substantial hardship for railroads and their customers.

The price of railroad fuel toward the end of 2000 was the highest during the past 20 years, and likely the highest ever. As of the end of 2000, the average price paid by railroads for diesel fuel had rocketed to a level 239 percent of the price at the beginning of 1999. Long term contracts and customer agreements often limit the ability of railroads to recover major cost increases in a timely fashion. Thus, railroads are being forced to expend an additional $2.4 billion annually or $6.6 million more each and every day. Moreover, because this huge increase in costs is required to perform exactly the same level of service, these increased costs have a direct impact on the industry's financial bottom line. In fact, they represent an amount equal to three-quarters of industry net income.

Looking ahead, future pricing policies will have to include major price increases to recover lost profitability as a result of fuel cost increases. Some shippers have indicated that they will be unable to absorb these transportation rate increases and will be forced to pass the expense on to their customers.

Because railroads have huge fixed costs to cover, it makes economic sense to move traffic that is marginally profitable (i.e., railroads handle traffic that is slightly above variable cost because it contributes to fixed cost). However, the fuel cost increases have raised our variable costs to such a degree that, in some segments, variable costs are becoming higher than the revenue, and traffic that has been historically profitable may have to be eliminated.

Moreover, higher energy prices are having a negative effect on some freight shippers, a development that affects freight railroads indirectly. For instance, eight of the ten major aluminum producers served by one leading railroad are currently shut down, and the remaining two are operating at 50 percent capacity. Instead of producing product, these companies are selling their allotted power.

Other railroads report that dramatically higher natural gas prices have led to significant traffic losses due to reductions in production and plant closures in areas such as plastics, cement, fertilizer, and intermediate gases such as propane and butane.

For these reasons, AAR encourages you to take strong and immediate action to formulate an effective national energy strategy. In addition to urging support for actions to reduce energy prices and for the positions of the Coal-Based Generation Stakeholders group, I am pleased to enclose AAR briefing papers on the following three railroad priorities: repeal of the 4.3 cent per gallon "deficit reduction" diesel fuel tax, an acceptable resolution of the coal mine valley fill issue, and establishment of a locomotive fuel efficiency program within the Department of Energy.

AAR looks forward to working with you and the other members of the Energy Policy Development Task Force to craft a balanced and effective energy policy for our nation.

Sincerely,

Ed

Edward R. Hamberger

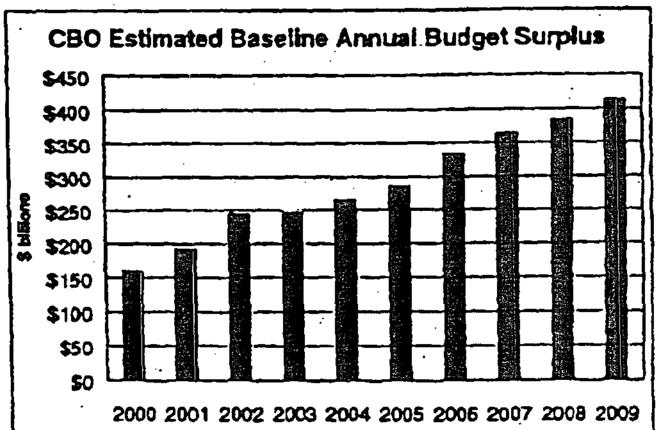
cc: The Honorable Norman Mineta
The Honorable Spencer Abraham
Mr. Lawrence Lindsey
Mr. Andrew Lundquist
Ms. Karen Knutson
Mr. John Frenzel

Repeal Deficit Reduction Fuel Taxes

AAR supports S. 820 and H.R. 1001 that would repeal deficit reduction fuel taxes paid by railroads and barges. AAR opposes H.R. 2060 that would create a railroad trust fund from deficit reduction fuel taxes.

Inequitable Taxation In a Surplus Environment

The railroad and inland barge industries pay a 4.3 cents per gallon deficit reduction fuel tax even though there is no longer a federal deficit. Furthermore, the railroad and inland barge industries are required to pay deficit reduction fuel taxes while their competitors, the truckers, do not.



Source: CBO, The Economic and Budget Outlook: An Update (July 1999)

Among all U.S. industries, only transportation industries have been obligated to pay special deficit reduction fuel taxes, and today, among the different transportation modes, only railroad and barge companies continue to pay such a tax. The deficit reduction fuel tax rate has varied over time, and currently stands at 4.3 cents per gallon on diesel fuel consumed. Since inception of the tax in 1990, freight railroads have paid over $1.4 billion in deficit reduction fuel taxes. Railroads continue to pay these taxes even though there is no longer a federal deficit.

Trucking companies, direct competitors of railroads and barge companies, do not pay a deficit reduction fuel tax. The entire revenue from the taxes paid by the truckers is paid into the Highway Trust Fund, and is used to pay for improvements and maintenance of highway infrastructure. Therefore, while railroads continue to contribute to a non-existent deficit, the truckers contribute to their own infrastructure improvement.

By contrast, the railroad industry does not have a trust fund but privately funds its own maintained rights-of-way. In 1998, freight railroads spent $7.7 billion maintaining and improving their own infrastructure. This is equivalent to a tax of $2.13 per gallon of fuel consumed by railway locomotives — an amount, which is four to ten times the equivalent of tax paid by the competing modes of transportation.

Both the House and Senate 1999 tax cut bills, acknowledged the tax inequity and included a repeal of the 4.3 cent deficit reduction fuel tax for the railroad and barge industries, but the final 1999 tax cut bill was vetoed by President Clinton for reasons other than the railroad tax repeal.

Support for an Equitable Solution

The railroads are not alone in calling for a fair and equitable solution to the current deficit reduction fuel tax problem. The U.S. Chamber of Commerce and the American Road and Transportation Builders Association (ARTBA) have adopted policies in support of repealing the 4.3-cent deficit reduction fuel tax. Numerous agriculture groups including the American Farm Bureau Federation, American Soybean Association, National Association of Wheat Growers, and the National Corn Growers Association are also on record supporting the repeal of this tax.

Railroad Trust Fund Proposals

AAR opposes H.R. 2060, the Railway Safety and Funding Equity Act of 1999 (RSAFE), a bill that would transfer the 4.3-cent deficit reduction fuel tax into a new Railroad Trust Fund for highway-rail grade crossing safety programs. H.R. 2060 would divert significant railroad resources to help solve what is fundamentally a highway safety problem. Not only is this proposed cross subsidy of highway needs by the railroads bad public policy, but these railroad fuel tax revenues are needed to meet significant railroad infrastructure needs.

AAR also opposes any effort to use the 4.3 cents per gallon deficit reduction fuel tax paid by the railroads to create a Railroad Trust Fund to finance short-line/regional railroad improvements, intercity or commuter passenger rail needs, or other purposes. In these scenarios, the beneficiaries of the funds, while having contributed little or nothing, would profit from a cross-subsidy from the large freight railroads. It is not appropriate to expect the large railroads to provide additional funding support for passenger rail, short-lines, or highway-rail traffic control devices. Neither do large railroads care to finance their own infrastructure needs through a Railroad Trust Fund by inefficiently sending funds to Washington, DC, simply to be returned to private sector railroads, minus bureaucratic administrative and overhead costs, and subject to political manipulation and government regulatory red tape.

Summary

The railroads' true advantage in cost, environmental impact, reduced highway damage and congestion, safety, and fuel efficiency rightfully have become important criteria in a modal choice. Artificial cost barriers to the use of freight transportation, in terms of inequitable deficit reduction taxes, can only disadvantage rail in the competitive marketplace and distort consumer choice.

AAR supports S. 820 and H.R. 1001 that would repeal the 4.3 cents per gallon deficit reduction fuel tax for the railroads and barges. This tax should be repealed because it is:

1. Discriminatory against railroads, since the trucking industry pays no deficit reduction fuel tax;

2. Economically unsound, because it artificially diverts traffic that other wise would travel by rail; and

3. Inconsistent with national policy, because it violates the goals of economy, impartiality, energy efficiency, and environmental friendliness.

Additionally, large freight railroads oppose the transfer of these revenues to a federal Railroad Trust Fund or any other form of a transportation trust fund.

THE COAL MINE VALLEY FILL ISSUE

DESCRIPTION: In October 1999, a federal district court in West Virginia stunned the Nation's coal industry with a decision barring the longstanding practice of building valley and hollow fills to store the dirt and rock generated during coal mining. *Bragg v. Robertson*, 72 F. Supp. 2d 642 (S.D. W.Va. 1999), *appeal pending*, No. 99-2443 (4th Cir). Notwithstanding the fact that these engineered fill structures are both a necessary part of coal mining operations and expressly authorized by federal laws regulating coal mining, the court interpreted regulations issued under those laws as prohibiting their construction in hollows and valleys that inevitably contain stream courses. While the decision remains pending on appeal, the past Administration abandoned the working men and women of America's coal industry and announced that it now agreed with the court's view. The past Administration's action in this regard is not only contrary to the laws it administers, it will have economic consequences in West Virginia alone that a Marshall University study concluded will be "as great or greater than those of the Great Depression." Earlier in the same litigation, the federal agencies (EPA, OSM & COE) settled the claims related to the use of section 404 permits to authorize these fills under the Clean Water Act. The agencies agreed to conduct a programmatic Environmental Impact Statement which addresses environmental and economic consequences of different actions, as well as evaluate the better coordination of overlapping regulatory programs.

STATUS: The appeal in the 4th Circuit has been briefed and was argued on December 7, 2000. In the meantime, the EPA, OSM and COE are preparing a Draft EIS. EPA and COE also have pending a proposed rule published on April 20, 2000 clarifying that excess spoil is fill material subject to section 404 and not section 402 of the CWA. This rule would remove the ambiguity in the agencies' programs that the district court relied on to reach its erroneous conclusion that these fills as well as other activities that have the effect of replacing waters of the United States are not authorized by section 404.

KEY DECISIONS: Should any part or form of a Draft EIS be publicly released before the completion of the underlying technical, economic and other studies?
OPTIONS: * Delay public release of Draft EIS in any form until all the underlying studies are complete and have been subject to some form of peer review. This option is completely defensible and will assure that the EIS process on this matter will not be subject to criticisms related to its credibility and integrity.

*Allow the agencies to release an executive summary or other form of a draft EIS that purports to provide an overview of the current analysis of complex technical questions. This option will appease few and invite strong criticism from industry and, perhaps, the West Virginia state legislature that has funded part of the studies.

KEY DECISIONS: Whether EPA and COE should adopt as a final rule the proposal clarifying the scope of the section 404 program with respect to excess spoil and other activities that have the effect of replacing waters of the United States.
OPTIONS: * Proceed to adopt as final the proposed rule published on April 20, 2000. The rule is an important part of maintaining the integrity of the 404 program by clarifying a longstanding ambiguity that has caused grave uncertainty for the regulated community and the agencies. It not only addresses the excess spoil issue but other activities as well, e.g. landfills.

* Await the decision of the 4th Circuit to determine whether it would require any modification of the proposal to address the central features of the rule. At some point, the EIS on mountaintop mining will have to analyze how excess spoil fills are to be addressed within the prevailing regulatory schemes under the CWA and SMCRA and whether any conflicts exist.

Public-Private Fuel Efficiency and Emissions Partnerships

ASSOCIATION OF AMERICAN RAILROADS | RAIL POLICY 2001

WHAT SHOULD BE DONE?	Establish a public-private partnership involving the federal government, railroads, and railroad suppliers designed to increase the fuel efficiency of, and reduce emissions from, diesel locomotives. The partnership should be similar to the "21st Century Truck Initiative" now underway.
WHY?	The partnership would encourage conservation of natural resources and reduced emissions by the nation's largest freight transportation provider. Moreover, the "21st Century Truck Initiative" will use hundreds of millions of dollars of federal funds to sharply increase fuel efficiency and lower emissions for motor carriers that compete against railroads. Equity demands that railroads receive the same support.

ISSUE OVERVIEW

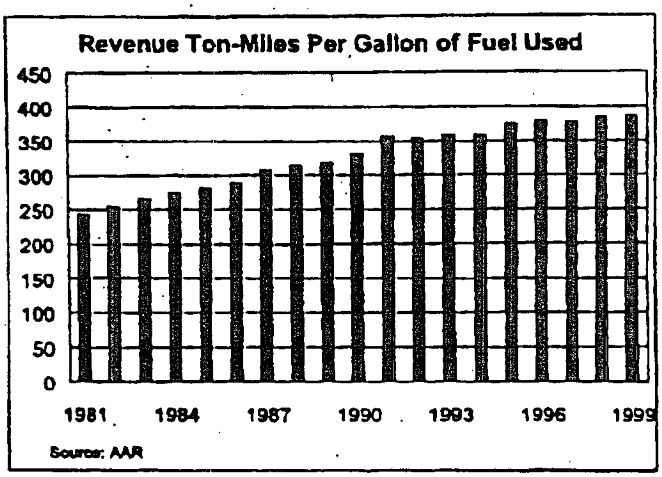
In April 2000, the Clinton Administration announced the creation of the "21st Century Truck Initiative," a public-private research partnership involving many of the nation's largest heavy-duty engine and truck companies; the U.S. Departments of Defense, Energy, and Transportation; and the Environmental Protection Agency.

The goals of the Truck Initiative include developing truck and bus technologies that increase fuel economy, improve safety, reduce emissions, and lower costs. The partnership is designed to lead, within 10 years, to prototypes that double existing fuel economy for long-haul trucks and significantly reduce truck emissions of nitrous oxide, particulates, and other air pollutants.

Because of the Truck Initiative, the fiscal year 2001 budget saw an increase of $31 million in truck research spending to a total of $137 million.

Railroads account for more than 40 percent of the nation's freight ton-miles, considerably more than trucks' 29 percent share. Therefore, increases in rail fuel efficiency would significantly benefit our economy and environment. However, there is no public-private program involving railroad locomotives similar to the Truck Initiative. Instead, railroads and their suppliers must fund research and development efforts aimed at increasing fuel efficiency and reducing emissions on their own. For example, the Burlington Northern and Santa Fe Railway and the Union Pacific Railroad are spending more than $1 million apiece on these issues, while the Association of American Railroads is funding an industry-wide emissions research program.

- A federal program to increase fuel efficiency and reduce emissions from diesel locomotives will provide public benefits to the environment similar to those of the 21st Century Truck Initiative.
- By providing motor carriers a major federal subsidy through the Truck Initiative, the federal government will artificially reduce motor carrier costs. This imbalance between trucks and railroads will encourage shippers to use trucks, even where railroads provide more efficient services.
- The U.S. Department of Transportation's *Moving America: New Directions, New Opportunities — A Statement of National Transportation Policy* notes that "Federal programs and policies must treat modes and carriers fairly." This condition is clearly violated if motor carriers receive federal benefits not made available to their competitors.
- A federal program will magnify the substantial strides in both fuel efficiency and emissions control already accomplished by the railroads. Railroad fuel efficiency is up 16 percent since 1990 and 58 percent since 1980. Railroads are also committed to substantial reductions in atmospheric emissions, having endorsed an EPA proposal that calls for a 60 percent reduction in nitrogen oxide emissions from locomotives manufactured beginning in 2005. With federal support, the railroad industry can build on its own voluntary achievements and foster improved conservation and emissions control.



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A SELECTIVE NUCLEAR ENERGY R&D PROGRAM UNDER SEVERE BUDGET RESTRICTIONS

The broad R&D program (Table 1) recommended by the Nuclear Energy Research Advisory Committee (NERAC) in June 2000 comprises the essentials to assure a re-vitalization of U. S. nuclear energy capability. The funding recommendation, although much higher than present nuclear energy R&D funding by DOE ($70 million in FY2001), is very low compared to funding of alternative fossil and renewable energy sources ($265 million / yr. in 2005 versus $545 million and $373 million in FY2001 for fossil and renewable energy, respectively) If $265 million is not forthcoming because of budget constraints, what should be selected as having the highest priority and at what levels?

The answer has to be shaped from the overall priorities in, and the responsibilities for, actions to revitalize the nation's nuclear power enterprise. These actions, given in order of priority, are interdependent, each depending on effective progress on the preceding one:

(1) Safe and economic operation of the present fleet of U.S. nuclear power plants over an extended lifetime of 60 years, is essential to gain investor confidence in building new plants, and the prime responsibility of industry. (The NEPO program is a miniscule part of this overall industry effort, simply an acknowledgment that the DOE cares about continued viable operation of U.S. nuclear plants.)

(2) A decision to proceed with the licensing and construction of a permanent repository for spent nuclear fuel at the Yucca Mountain site. Continued uncertainty on providing the repository is a major barrier to expanding nuclear power in the U.S. DOE carries full responsibility, although the industry pays the way.

(3) Building new nuclear power plants in the U.S. in this decade. The need to minimize financial risk to the private sector investors places a high premium on proven technology and assured licensability. The NRC's standardization policy (as incorporated in CFR Part 52) provides a stable and timely licensing process. It is essential to obtain an early site permit (or equivalent) and a certified design with which to achieve a combined construction and operating license before a private sector owner(s) puts up the major investments to construct a nuclear plant. Plants that already have NRC design certification (presently all advanced light water reactors) should be given the highest priority for this reason. **The private sector has the prime investment responsibility**, but since the government is responsible for the crucial element of regulation, it is reasonable to expect some resource sharing from DOE to implement the critical elements of the standardized licensing process. More nuclear power capacity in the short term will pave the way for advanced nuclear power plants in the long term by sustaining investment confidence in nuclear power while establishing the demand for an expanded nuclear fuel supply.

(4) Developing advanced nuclear power plants that are capable of sustaining nuclear energy production over the long term, in particular by opening up the vast reserves of nuclear fuel contained in uranium and thorium. Incorporation of advanced technology will provide for even greater safety and environmental benefit, assured proliferation resistance, and improved economy. Because of the long time before deployment can be realized government **has the prime responsibility for this effort.**

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DOE024-0966

Government funding in FY 2002 for the above four efforts in a very restricted budget should be in accordance with the following pattern (Industry co-sharing is also indicated):

(1) Continued DOE support of the NEPO program at a level of $10 million annually, shared by industry at $10 million annually. Industry is independently expending at least $80 million annually if only EPRI funds are included. Total funding: >$100 million, $10 million by DOE.
(2) Utilization of the presently planned DOE budget on the Yucca Mountain project to permit a go-ahead decision on the repository. Present budget: $390.4 million, provided by rate-payers to DOE through nuclear utilities)
(3) DOE budget support of selective actions to achieve near term deployment of design certified advanced light water reactor plants at a level of $28 million, matched by industry, to:

- obtain early site permits.
- define the detailed process of obtaining a combined construction and operating plant and assuring that both the construction is carried out and the plant is operated in accord with the license.
- develop advanced information management and virtual construction technologies to reduce ALWR capital costs and construction times.
- support a design certification application for a passive ALWR (AT-1000), twice the power output of the presently certified design (AT-600).

A significant portion of these funds are to pay for NRC fees for the required licensing action. Total funding: $56 million, equally shared by industry and government.

(4) DOE support of advanced nuclear power plant development through a modest expansion of the NERI Program, the International NERI program, continued support of the Roadmap development for future nuclear power plants, and initiation of NRC confirmatory testing of the fuel and power conversion materials for the Pebble Bed Modular Reactor (Industry, through international participation in the S. African PBMR development, will fund the design and initial test). **Total funding: $75 million**, a small portion of which is cost-shared by contractors.

Thus, funding in FY2002 for these efforts, in a very restricted budget, should be at least $113 million, compared with $39 million at present.

Contacts
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Robert N. Schock, Lawrence Livermore National Laboratory; 925-422-6199, schock1@llnl.gov

Table 1. NERAC* Recommended Funding Need.

Area	2005 R&D Funding Need ($Millions)	Comments
Science & Engineering	60	
Nuclear Power	132	includes $20M for TREAT + $10M for ATR
Isotopes	23	No new facility
Space Nuclear	25	
Proliferation Resistance	25	TOPS report
TOTAL	265	

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DOE024-0967

*Long-Term Nuclear Technology Research and Development Plan, June 2000, http://nuclear.gov

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AGA

American Gas Association

March 1, 2001

Natural Gas Utilities
Recommendations for National Energy Policy

Overview

It is in the nation's best interest to cultivate and develop a varied portfolio of energy resources that makes the most of each fuel's unique attributes and advantages. Natural gas is making a significant contribution to meeting Americans' energy needs for an affordable, reliable energy resource. In order to provide Americans an energy future that is free of oil embargoes and rolling power blackouts, we must now adopt a balanced national energy policy that recognizes the vital role of natural gas. Such a policy provides the energy to ensure the prosperity of American families and businesses.

Future of Natural Gas in the United States

The United States relies on natural gas for one-fourth of its energy needs. Natural gas burns cleaner than any other fossil fuel, is almost 100 percent North American and provides efficient, responsive heat and energy for consumers. Because of the many advantages that natural gas offers Americans, demand for natural gas could grow by as much as 60 percent in the ~~first~~ last two decades of the 21st century, according to projections by the Department of Energy and the American Gas Foundation -- but only if recommended policy changes are made.

Results of Greater Use of Natural Gas

The increased use of natural gas would provide numerous benefits for all Americans:

- Lower oil imports by 4.5 million barrels per day, providing **national security.**
- Provide Americans an extremely **efficient** use of energy, especially in its "direct" applications, such as furnaces, water heaters, microturbines, desiccant dehumidifiers and combined heat and power.
- Supply needed relief to the over-burdened electric grid, along with greater **reliability** to businesses and home offices, through new technologies which generate both heat and electricity and can be sited closer to the consumer.
- **Clean** up the air by lowering carbon dioxide emissions by 930 million tons per year.

(Over for AGA's specific policy recommendations)

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AGA
American Gas Association

March 1, 2001

AGA's Recommendations for a National Energy Policy

- **Protection of low-income consumers:** Expand current Low Income Home Energy Assistance Program (LIHEAP) and weatherization funding.
- **Expansion of natural gas infrastructure**: Change the current tax depreciation schedule for natural gas utility expenses to an accelerated 7-year schedule. This will free up capital for natural gas utilities to invest in new pipelines, storage facilities and upgrading the existing infrastructure; ensuring continued reliable service for all natural gas consumers. Also increase RD&D on natural gas infrastructure reliability and safety; repeal tax on new customer connections (Contributions in Aid of Construction.)
- **Development of new natural gas technologies:** Provide RD&D funding for new technologies to produce, deliver and use natural gas in a highly-efficient and safe manner; provide favorable tax treatment for highly efficient end-use technologies; reduce or eliminate barriers to market entry.
- **Increased energy efficiency**: Provide funding to improve the energy efficiency of government facilities and schools; RD&D and tax incentives for highly efficient technologies; policy recognition of total energy efficiency.
- **Adequate supplies of natural gas**: North America has abundant supplies of natural gas. More supply of natural gas means lower prices for consumers. AGA supports the recommendations by natural gas producers for expanded access to federal lands for exploration and production; tax provisions to stimulate domestic production; simplified agency review and permitting process.

\- AGA -

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DOE024-0970

AGA
American Gas Association

Federal Energy Legislation

Comparison of AGA Recommended Provisions And Provisions Contained in Senator Murkowski's National Energy Security Act of 2001 (S. 389)

Summary: The bill introduced by Senator Murkowski contains almost every provision recommended by AGA. It would:

+ • **Encourage increased production of natural gas**

0 • **Allow seven-year depreciation of all new natural gas distribution, transmission, and storage facilities (representing potential tax savings to AGA gas distribution members of approximately $8 billion over ten years)**

0 • **Repeal CIAC and PUHCA** +

+ • **Remove barriers to infrastructure expansion**

• **Create incentives for distributed generation and**

+ • **Increase LIHEAP authorizations.**

On November 30, 2000, the Government Relations Policy Committee and the Executive Committee of the Board of Directors created the AGA Energy Legislative Steering Committee under the leadership of Dick Reiten of NW Natural. During the months of December and January, the steering committee worked closely with AGA Staff to craft a set of core principles essential to any legislation as well as specific legislative proposals embodying the advocacy priorities of AGA member companies. The result of these efforts was circulated on January 16, 2001, and was approved by the GRPC and the AGA Board of Directors on February 26, 2001. AGA Staff has also been working with other associations and Congressional Staff to ensure that these principles and proposals are incorporated in the comprehensive, bipartisan legislation that will soon be a topic of Congressional attention.

On February 26, 2001, Senator Frank Murkowski, Chairman of the Senate Energy and Natural Resources Committee, introduced the National Energy Security Act of 2001 (S. 389.). This bill addresses a broad spectrum of energy issues and incorporates most of the principles and proposals that AGA has advocated throughout this effort. This memorandum highlights the natural gas provisions of interest to AGA members in the bill as well as some of the other more important energy issues it addresses.

Although much effort has already been invested, introduction of the Murkowski bill is only the starting point in the legislative process. AGA Staff will work closely with Senator Murkowski, his staff, other Senators, Members of the House of Representatives, and the Bush Administration in the weeks ahead to advance the AGA legislative proposals approved by the GRPC.

Following is a brief summary of what is included in the bill, organized to follow the order of the legislative proposals as recommended and ultimately approved by the AGA Legislative Steering Committee and GRPC.

Federal E&P Studies

The bill calls for reports on all federal actions affecting energy supply or delivery and annual reports on progress toward energy independence, which would be produced by DOE rather than the National Academy of Sciences. (Sections 101, 102.)

Renewal and Expansion of Infrastructure

Senator Murkowski has decided not to mandate a White House Office of National Energy Policy in light of President Bush's creation of a Cabinet-level "National Energy Policy Development Group" led by Vice President Cheney. The staff director of this group is Andrew Lundquist, until recently the staff director of the Senate Energy and Natural Resources Committee. However, codifying such an effort in the Executive Office of the President is still desirable.

The bill requires federal studies of rights of way over federal lands to determine which of these can support additional energy infrastructure. (Section 104.)

It requires FERC and other pertinent agencies to review the pipeline certification process to determine where time and cost can be saved. (Section 109.)

The bill requires DOE, FERC and other agencies having a role in the pipeline certification process to enter into an interagency agreement regarding environmental review of interstate pipeline certificate applications with deadlines for completion of required review. (Section 113.)

It requires DOT to implement an accelerated cooperative program of R&D regarding pipeline safety. (Section 114.)

The bill contains several significant tax incentives to expand infrastructure that are described under Tax Provisions in this memorandum.

Equitable Energy Efficiency Regulations

The bill does not address the need to give fair and equitable treatment to natural gas in energy-efficiency standards and related administrative proceedings before DOE and other federal agencies. AGA expects to continue to pursue this issue as this bill and others move forward through Congress.

LIHEAP

The bill increases LIHEAP authorization to $3 billion annually for the years 2000-2010 and $1 billion in emergency funds annually. It does not call for indexing authorizations to rising costs. (Section 601.)

Building Efficiency

The bill extends authority regarding federal energy-savings performance contracts. (Section 605.)

The bill creates in DOE an energy-efficient schools program, with authorizations in excess of $200 million. (Section 602.)

Tax Provisions
The bill provides for seven-year tax depreciation for new natural gas pipe, storage facilities, equipment and appurtenances. (Section 921.) It also allows the expensing of storage facilities. (Section 922.)

It provides for a tax credit for distributed power facilities used in nonresidential real or rental residential property used in trade or business (in excess of 1 kW) and used in manufacturing or plant activities (in excess of 500 kW). A credit is also extended to combined heat and power systems. (Section 971.)

The bill provides for the repeal of the tax on contributions in aid of construction (CIAC). (Section 959.)

The bill provides tax incentives for NGVs and other alternative-fuel vehicles. (Sections 981-985.)

New Natural Gas Technologies
DOE is required to conduct a five-year RD&D program to increase the reliability, efficiency, safety, and integrity of the natural gas delivery infrastructure and for distributed energy resources with such funds authorized as are necessary. (Section 115.)

Each federal agency is required to carry out periodic review of its regulations to ensure that they do not inhibit market entry of new energy-efficient technologies. (Section 112.)

Production Incentives
- Tax credit for nonconventional fuels (Section 29)
- Expensing geological and geophysical costs and shut-in royalties
- Tax credits for marginal oil and gas wells
- Royalty relief when the Henry Hub price is less than $2.30 per MMBtu
- Deepwater royalty relief

Other significant gas-related provisions included in the Murkowski bill include:
- PUHCA repeal
- Improvements to federal oil and gas leasing management, including the ability of states to assume responsibility for leasing on federal lands
- ANWR leasing program
- FERC jurisdiction over wholesale electric reliability
- Prospective PURPA repeal
- Tax credits for energy-efficient appliances and homes

A copy of the complete bill can be downloaded at:
http://thomas.loc.gov/cgi-bin/query/z?c107:S.389: or at http://energy.senate.gov

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23567

DOE024-0973

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NERC
2001 Summer Outlook for Electricity Reliability

May 15, 2001

Reliability Assessment Subcommittee (RAS)

- Mission: Assess the reliability of the North American bulk electric system
  - Seasonal assessment reports
  - Long-term (10 year) assessment reports
- Members:
  - Industry experts from across the continent

2001 Summer Reports

- Summer Assessment– Reliability of bulk electric systems throughout North America
- Special Assessment–In-depth assessment of California and the Pacific Northwest

Available at www.nerc.com

Summary of Expected Summer Conditions

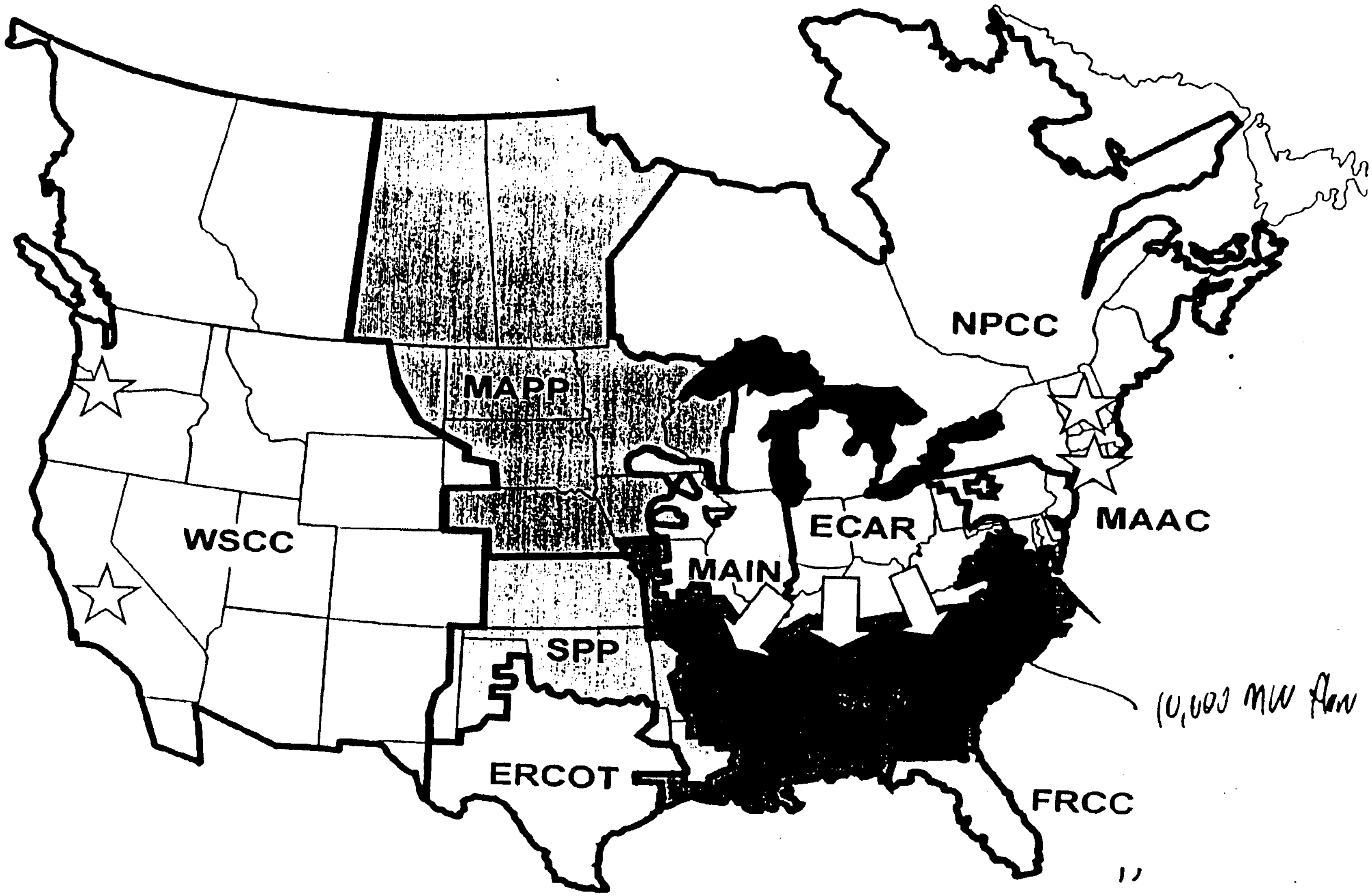
- Rotating blackouts in California throughout the summer
- Tight capacity conditions in Pacific Northwest, New England, and New York City Southeast
- Continued heavy loadings on transmission system

- special report on CA and PNW

Summary of Expected Summer Conditions

- Resources expected to be adequate in other areas
- Electric power system still vulnerable
  - Widespread heat wave
  - Higher than expected generator unavailability
  - Transmission equipment failure

Summer "Hot Spots"



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CAISO

- Independent NERC assessment
- *CAISO Summer Assessment 2001* report used as a starting point

March 2001

- NERC believes supply shortages will be greater than expected by the CAISO

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CAISO

- NERC expects:
  - Rotating blackouts during about 260 hours over the summer
  - Average amount of involuntary demand reductions about 2,150 MW
  - CAISO may be short as much as 5,500 MW during peak periods

- 10% of summer
- 7 hours per week

- rate increase of 49% would eliminate the shortfall

- shortage, [illegible] demand response to rate increase

CAISO

- Uncertainties:
  - Effects of conservation efforts
  - Customer response to rate increases
  - Performance of generators
  - Amount of new capacity added
  - Weather (temperature and rainfall)

Pacific Northwest

- Entire area in severe drought for past year - snow pack, stream flow, reservoir levels
- Water at critically low levels
- Area depends upon hydropower resources for about 2/3 of its electricity production

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Pacific Northwest

- Hydro generators have the ability to produce full output for a short time, but cannot sustain this level
  - Less electricity to share with neighbors (California)
  - Area susceptible to long term heat waves

in the peak up to 300j [illegible] CA [illegible]

Pacific Northwest

- NERC expects:
  - Able to serve local firm demand this summer.
  - Not much help for California.
  - Rotating blackouts are a possibility in winter 2001/2002 unless significant precipitation occurs

- area for concern in past 4-5 years
- margin up from 12 to 12.4 %

New England

- Improvements since last summer:
  - Over 2,300 MW of new generation
- Issues:
  - Capacity margin still tight
  - About 1,500 MW available from Quebec
  - Imports from Quebec not firm
- NERC expects:
  - New England will be tight, but adequate

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New York City

- Improvements since last summer:
  - About 600 MW of additional generation
- Issues:
  - Opposition to construction of new combustion turbines and generator re-powering project
- NERC expects:
  - NYC will be tight but adequate IF all new generation is in service this summer

Transmission Issues

- Heavy north-to-south electricity transfers experienced last summer
  - Many Transmission Loading Relief procedures (TLRs) called to alleviate constraints
  - Concerns about transmission voltage problems in Kentucky and Tennessee
- A repeat is possible this summer if similar weather and fuel price conditions occur

Recap

- Rotating blackouts in California throughout the summer
- Tight capacity conditions in Pacific Northwest, New England, and New York City
- Continued heavy loadings on transmission system

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National Environmental Strategies

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FAX TRANSMISSION COVER SHEET

Date:	April 18, 2001
To:	Joe Kelliher
Fax:	586-7210
Re :	Mercury Document for Meeting w/Steve Griles, Marc Himmelstein, et. al.
Sender:	Holly Hopkins

YOU SHOULD RECEIVE 2 PAGES, INCLUDING THIS COVER SHEET. IF YOU DO NOT RECEIVE ALL THE PAGES, PLEASE CALL (202) 333-2524.

Please note attached.

Resolution of EPA Mercury Regulatory Determination

Problem: On December 14, 2000, EPA issued a "regulatory determination" under the Clean Air Act (CAA) that regulation of mercury and possibly other hazardous air pollutants (HAPs) is "appropriate and necessary" for coal- and oil-based power plants. This decision automatically triggers a formal rulemaking. EPA is scheduled to issue a proposed rule in late 2003, a final rule in late 2004, and to require compliance by late 2007. Because of the specific language EPA used in the regulatory determination, the pending rulemaking *must* result in the imposition of "maximum achievable control technology" (MACT) standards for mercury and possibly other HAPs. Effective immediately, before EPA has determined through rulemaking what level of control should be required on a national basis, new and reconstructed plants *must* undergo case-by-case MACT review for mercury and other HAPs.

Status: The utility industry has filed a Petition for Review in the D.C. Circuit. The industry is *not* challenging the basic decision to regulate mercury emissions, but just the two MACT-related issues. On April 9, EPA filed a motion arguing the court has no jurisdiction to review these issues because the agency's decision has "no regulatory impact." The utility industry also has filed an administrative petition with EPA, requesting the reconsideration of that portion of the regulatory determination that prescribes a MACT program and immediately impacts new and reconstructed plants. EPA has not yet responded to this petition.

Implications: EPA's announcement is inconsistent with national energy policy objectives because it will limit fuel choices, impede the construction of new power plants during the next four years, and increase the cost of electricity. Several studies have estimated mercury control costs of $5 - $15 billion annually. In addition, recent analysis shows that the MACT program contemplated by the regulatory determination would impact utilities in the same manner as a Kyoto-type CO_2 program, in that it would cause significant fuel switching from coal to natural gas (50 percent decline in coal use in 2020).

Possible Resolution: EPA's regulatory determination should be modified to remove the legal bias in favor of a MACT requirement and to clarify that the agency intends to consider all available regulatory and policy options during the pending mercury rulemaking. This could be accomplished through a brief *Federal Register* notice issued within the next two months to ensure that (1) no new planned electricity generation is impeded by the case-by-case MACT review process; (2) this issue is addressed administratively rather than in court, and (3) the clarification can be explained in the context of the Administration's energy policy.

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Federal Energy Efficiency Tax Incentives and Programs- Highlights

Tax credit for solar energy systems. Provides a 10-percent business energy investment tax credit for qualifying equipment that uses solar energy to generate electricity, to heat or cool, to provide hot water for use in a structure, or to provide solar process heat.

Tax credit for electric vehicles. Provides a 10 percent credit (up to $4,000) for the cost of a qualified electric vehicle. The full amount of the credit is available for purchases prior to 2002.

Energy Star. First was introduced by the EPA in 1992 as a voluntary labeling program designed to identify and promote energy-efficient products, EPA partnered with DOE in 1996 to promote the Energy Star label, to cover new homes, most of the buildings sector, residential heating and cooling equipment, major appliances, office equipment, lighting, and consumer electronics.

Efficiency Standards. DOE develops and promulgates energy efficiency standards for categories of appliances and develops testing methodologies used to set standards and to provide efficiency rating labels. (DOE's rating and labeling programs are performed in partnership with the Federal Trade Commission.) The standards and test procedures R&D also supports the joint EPA-DOE Energy Star program.

Building America Program. DOE creates partnerships with traditional housing developers and manufacturers of industrialized housing to demonstrate how new technologies can be integrated into homes cost-effectively and to disseminate that knowledge to other builders. DOE funds research on more efficient building equipment and appliances, such as advanced lighting, heat pumps, chillers, and commercial refrigeration.

Partnership for Advancing Technology in Housing (PATH). PATH is a partnership between the Federal Government and the housing industry to develop and deploy housing technologies to make new homes 50 percent more energy efficient and to make at least 15 million existing homes 30 percent more energy efficient within a decade. The program coordinates work in the Department of Housing and Urban Development, the Department of Energy, the Environmental Protection Agency, the Federal Emergency Management Agency, the Department of Commerce, and other agencies.

Transportation Technology Programs. DOE funds RD&D that can significantly alter current trends in oil consumption. Include funding for advanced power-train technology (direct-injection) engines, hybrid-electric drive systems, advanced batteries, fuel cells, and light weight materials and for alternative fuels (including ethanol from biomass, natural gas, methanol, electricity, and biodiesel).

Partnership for a New Generation of Vehicles (PNGV). A government (DOE, Commerece, DOT, EPA)--industry (Ford, GM, DaimlerChrsyler) partnership effort that aims to develop attractive, affordable cars to meet all applicable safety and environmental standards and get up to three times the fuel efficiency of today's cars. All three industry partners unveiled their PNGV "concept cars" in January and February of 2000.

Advanced Vehicle Technology Program. DOT works with other government agencies and private consortia to cooperate to promote research, development and deployment of technological advances in vehicles, components and related infrastructure.

Corporate Average Fuel Economy (CAFE). DOT is responsible for setting the Corporate Average Fuel Economy standards for new cars and light duty trucks as established under the Energy Policy and Conservation Act of 1975.

21st Century Truck Initiative. Modeled after the PNGV program, DOT is participating in the 21st Century Truck program to develop and demonstrate commercially viable truck propulsion systems technology that will improve the fuel economy of medium- and heavy-duty trucks and buses by two to three times while meeting or exceeding emission standards for 2010 and enhancing safety.

Clean Buses . DOT funds research in advanced technology buses . Eligible projects include purchase of clean-fuel buses, constructing, modifying or leasing facilities, and re-powering or retrofitting of existing buses. Eligible technologies include CNG, LNG, bio-diesel, battery alcohol-based fuel, hybrid electric, fuel cell or other zero-emissions technology.

Advanced Technology Transit Bus (ATTB) Program. DOT funds the develops and deployment a lightweight, low-floor, low-emissions transit bus using proven advanced technologies developed in the aerospace industries.

Congestion Mitigation Programs. DOT funds several programs aimed at ....

Industry Technology Programs. Under Industries of the Future, DOE works cooperatively with the nation's most energy-intensive industries (aluminum, glass, chemicals, forest products, mining, petroleum refining, and steel) to develop technologies that increase energy and resource efficiency.

Under *Industrial Combined Heat and Power (CHP) Systems,* DOE is developing new industrial CHP systems to capture thermal heat that would otherwise be wasted. EPA and DOE work to eliminate barriers to the rapid dissemination of combined heat and power technology.

Vision 21. DOE's Vision 21 initiative funds research aimed at finding ways to use coal and gas with efficiencies well beyond what is possible with today's technologies.

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For Immediate Release

Contact:
Ron Phillips
202/608-5906
Kathy Mathers
202/608-5906

U.S. Nitrogen Fertilizer Imports Rise Dramatically

January 22, 2001, Washington, D.C. -- Data released by the U.S. Department of Commerce demonstrate the impact high natural gas prices in the United States are having on the nitrogen fertilizer import market.

For the fiscal year to date, July – November 2000, U.S. nitrogen imports are up by 586,000 short tons of nitrogen, an increase of over 27 percent over the period July – November 1999.

Data for the month of November 2000 show anhydrous ammonia imports up 37 percent over November 1999. For the period covering July - November 2000, imports are up 17 percent over the previous year.

These figures are understated since they do not include imports of ammonia from Russia and the Ukraine, which are withheld by the Commerce Department . It is estimated that annual U.S. imports from these two countries range from 750,000 to 1.2 million tons.

The story is more dramatic for nitrogen solutions. Imports in November 2000 were up 74 percent over the same month in 1999, bringing the year-to-date total to a whopping 175 percent increase in imports.

Urea and ammonium nitrate imports are up also. Urea was up 56 percent for the month over the previous year, and 40 percent for the year to date. Ammonium nitrate imports rose 59 percent in November over the same month in 1999.

High natural gas prices in the United States have caused domestic nitrogen fertilizer producers to severely curtail production. Natural gas is a feedstock for making ammonia, which serves as a directly applied nitrogen fertilizer product and as the basis for making other nitrogen products. Natural gas is the major cost component of making ammonia, accounting for 75 to 90 percent of the cost of production. The production curtailments and higher nitrogen prices are largely the cause of the current surge in imports.

The Fertilizer Institute represents by voluntary membership more than 90 percent of the nation's fertilizer industry. Producers, manufacturers, retailers, trading firms and equipment manufacturers which comprise its membership are served by a full time Washington, D.C. staff in various legislative, educational and technical areas as well as with information and public relations programs.

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Calendar Entry:

Appointment

Subject:	MaryBeth re NEP		Location:	
Begins:	Fri 03/30/2001	10:00 AM	Entry type:	Appointment
Ends:	Fri 03/30/2001	10:15 AM		
Chair:	Abe Haspel/EE/DOE			

☐ Pencil In	Time will appear free to others.
☐ Mark Private	Others cannot see any details about this event.
☐ Notify me	Have Notes notify you before the event.
Categorize:	

Description:

23589

DOE024-0995

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Calendar Entry:

Appointment

Subject:	Mtg. with Margot Anderson re: NEP, room 7B-040		Location:	
Begins:	Mon 03/05/2001	01:00 PM	Entry type:	Appointment
Ends:	Mon 03/05/2001	02:00 PM		
Chair:				

☐ Pencil In — Time will appear free to others.
☐ Mark Private — Others cannot see any details about this event.
☐ Notify me — Have Notes notify you before the event.
Categorize:

Description:

23590

DOE024-0996

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THE WHITE HOUSE

WASHINGTON

January 29, 2001

MEMORANDUM FOR THE VICE PRESIDENT
THE SECRETARY OF THE TREASURY
THE SECRETARY OF THE INTERIOR
THE SECRETARY OF AGRICULTURE
THE SECRETARY OF COMMERCE
THE SECRETARY OF TRANSPORTATION
THE SECRETARY OF ENERGY
THE DIRECTOR OF THE FEDERAL EMERGENCY MANAGEMENT AGENCY
THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY
THE ASSISTANT TO THE PRESIDENT AND DEPUTY CHIEF OF STAFF FOR POLICY
THE ASSISTANT TO THE PRESIDENT FOR ECONOMIC POLICY
THE ASSISTANT TO THE PRESIDENT FOR INTERGOVERNMENTAL AFFAIRS

SUBJECT: National Energy Policy Development Group

One of the greatest challenges facing the private sector and Federal, State, and local governments is ensuring that energy resources are available to meet the needs of our citizens and our economy. To help address this challenge, I am asking the Vice President to lead the development of a national energy policy designed to help the private sector, and government at all levels, promote dependable, affordable, and environmentally sound production and distribution of energy for the future. Accordingly, I direct as follows:

1. Establishment. There is hereby established within the Executive Office of the President an Energy Policy Development Group, consisting of the following officers of the Federal Government: the Vice President, Secretary of the Treasury, Secretary of the Interior, Secretary of Agriculture, Secretary of Commerce, Secretary of Transportation, Secretary of Energy, Director of the Federal Emergency Management Agency, Administrator of the Environmental Protection Agency, Assistant to the President and Deputy Chief of Staff for Policy, Assistant to the President for Economic Policy, and Assistant to the President for

Intergovernmental Affairs. The Vice President may also invite the Chairman of the Federal Energy Regulatory Commission to participate. The Vice President may invite the participation of the Secretary of State when the work of the Energy Policy Development Group involves international affairs and, as appropriate, other officers of the Federal Government. The Vice President shall preside at meetings of the Energy Policy Development Group, shall direct its work, and may establish subordinate working groups to assist the Energy Policy Development Group in its work.

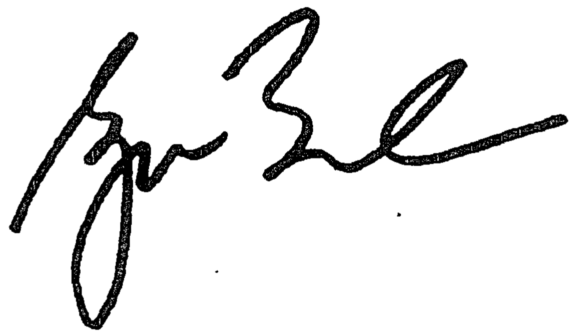
2. Mission. The mission of the Energy Policy Development Group shall be to develop a national energy policy designed to help the private sector, and as necessary and appropriate Federal, State, and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy. In carrying out this mission, the Energy Policy Development Group's functions shall be to gather information, deliberate, and, as specified in this memorandum, make recommendations to the President. Its activities shall not supplant the authority and responsibility of State and local governments for handling energy production, purchase, and distribution difficulties.

3. Reports. The Energy Policy Development Group should submit reports to me as follows: (a) in the near-term, an assessment of the difficulties experienced by the private sector, and State and local governments in ensuring that local and regional energy needs are met, and (b) as soon thereafter as practicable, a report setting forth a recommended national energy policy designed to help the private sector, and as necessary and appropriate State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future. The recommended national energy policy should take into consideration, among other things, (i) the growing demand for energy, locally, regionally, and nationally, in the United States and in the world, (ii) the potential for local, regional, or national disruptions in energy supplies or distribution, and (iii) the need for responsible policies to protect the environment and promote conservation, and (iv) the need for modernization of energy generation, supply, and transmission infrastructure.

4. Funding. The Department of Energy shall, to the maximum extent permitted by law and consistent with the need for funding determined by the Vice President after consultation with the Secretary of Energy, make funds appropriated to the Department of Energy available to pay the costs of personnel to support the activities of the Energy Policy Development Group. If a situation arises in which Department of Energy appropriations are not available for a category of expenses of the Energy

Policy Development Group, the Vice President or his designee should submit to me a proposal for use, consistent with applicable law, of the minimum necessary portion of any appropriation available to the President to meet the unanticipated need. The Vice President may also obtain, through the Assistant to the President for Economic Policy, such assistance from the National Economic Council staff as the Vice President deems necessary.

5. <u>Termination</u>. The Energy Policy Development Group shall terminate no later than the end of fiscal year 2001.



cc: Secretary of State
Chairman, Federal Energy Regulatory Commission

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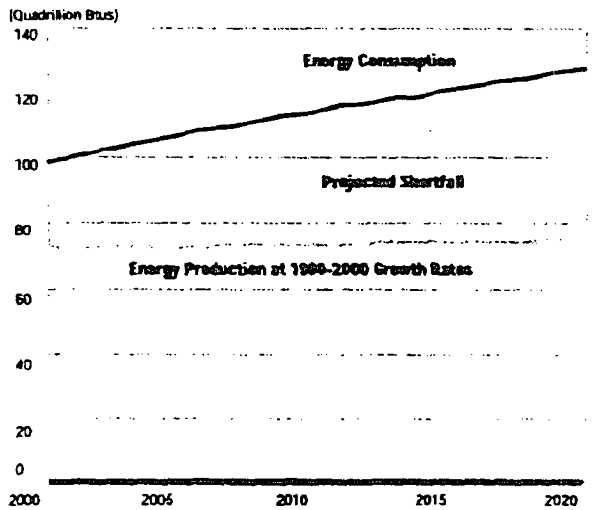
Overview

Reliable, Affordable, and Environmentally Sound Energy for America's Future

n his second week in office, President George W. Bush established the National Energy Policy Development Group, directing it to "develop a national energy policy designed to help the private sector, and, as necessary and appropriate, State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future." This Overview sets forth the National Energy Policy Development (NEPD) Group's findings and key recommendations for a National Energy Policy.

Figure 1
Growth in U.S. Energy Consumption Is Outpacing Production



Over the next 20 years, growth in U.S. energy consumption will increasingly outpace U.S. energy production, if production only grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

America in the year 2001 faces the most serious energy shortage since the oil embargoes of the 1970s. The effects are already being felt nationwide. Many families face energy bills two to three times higher than they were a year ago. Millions of Americans find themselves dealing with rolling blackouts or brownouts; some employers must lay off workers or curtail production to absorb the rising cost of energy. Drivers across America are paying higher and higher gasoline prices.

Californians have felt these problems most acutely. California actually began the 1990s with a surplus of electricity generating capacity. Yet despite an economic boom, a rapidly growing population, and a corresponding increase in energy needs, California did not add a single new major electric power plant during the 1990s. The result is a demand for electricity that greatly succeeds the amount available.

A fundamental imbalance between supply and demand defines our nation's energy crisis. As the chart illustrates, if energy production increases at the same rate as during the last decade our projected energy needs will far outstrip expected levels of production.

This imbalance, if allowed to continue, will inevitably undermine our economy, our standard of living, and our national security. But it is not beyond our power to correct. America leads the world in scientific achievement, technical skill, and entrepreneurial drive. Within our country are abundant natural resources, unrivaled technology, and unlimited human creativity. With forward-looking leadership and sensible policies, we can meet our fu-

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America's expanding economy, growing population, and rising standard of living will be sustained by our unmatched technological know-how.

ture energy demands and promote energy conservation, and do so in environmentally responsible ways that set a standard for the world.

The Challenge

America's energy challenge begins with our expanding economy, growing population, and rising standard of living. Our prosperity and way of life are sustained by energy use. America has the technological know-how and environmentally sound 21st century technologies needed to meet the principal energy challenges we face: promoting energy conservation, repairing and modernizing our energy infrastructure, and increasing our energy supplies in ways that protect and improve the environment. Meeting each of these challenges is critical to expanding our economy, meeting the needs of a growing population, and raising the American standard of living.

We are already working to meet the first challenge: using energy more wisely. Dramatic technological advances in energy efficiency have enabled us to make great strides in conservation, from the operation of farms and factories to the construction of buildings and automobiles. New technology allows us to go about our lives and work with less cost, less effort, and less burden on the natural environment. While such advances cannot alone solve America's energy problems, they can and will continue to play an important role in our energy future.

The second challenge is to repair and expand our energy infrastructure. Our current, outdated network of electric generators, transmission lines, pipelines, and refineries that convert raw materials into usable fuel has been allowed to deteriorate. Oil pipelines and refining capacity are in need of repair and expansion. Not a single major oil refinery has been built in the United States in nearly a generation, causing the kind of bottlenecks that lead to sudden spikes in the price of gasoline. Natural gas distribution, likewise, is hindered by an aging and inadequate network of pipelines. To match supply and demand will require some 38,000 miles of new gas pipelines, along with 255,000 miles of distribution lines. Similarly, an antiquated and inadequate transmission grid prevents us from routing electricity over long distances and thereby avoiding regional blackouts, such as California's.

"America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment."

— President George W. Bush

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Increasing energy supplies while protecting the environment is the third challenge. Even with successful conservation efforts, America will need more energy.

Renewable and alternative fuels offer hope for America's energy future. But they supply only a small fraction of present energy needs. The day they fulfill the bulk of our needs is still years away. Until that day comes, we must continue meeting the nation's energy requirements by the means available to us.

Estimates indicate that over the next 20 years, U.S. oil consumption will increase by 33 percent, natural gas consumption by well over 50 percent, and demand for electricity will rise by 45 percent. If America's energy production grows at the same rate as it did in the 1990s we will face an ever-increasing gap.

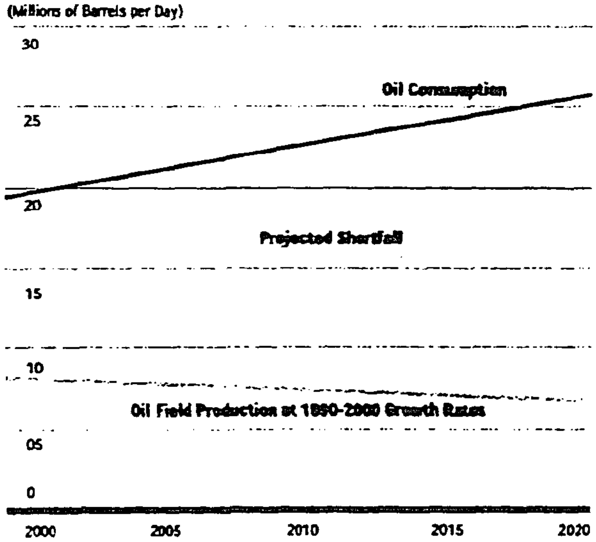
Increases on this scale will require preparation and action today. Yet America has not been bringing on line the necessary supplies and infrastructure.

Extraordinary advances in technology have transformed energy exploration and production. Yet we produce 39 percent less oil today than we did in 1970, leaving us ever more reliant on foreign suppliers. On our present course, America 20 years from now will import nearly two of every three barrels of oil – a condition of increased dependency on foreign powers that do not always have America's interests at heart. Our increasing demand for natural gas – one of the cleanest forms of energy – far exceeds the current rate of production. We should reconsider any regulatory restrictions that do not take technological advances into account.

Figure 2

U.S. Oil Consumption Will Continue to Exceed Production

(Millions of Barrels per Day)



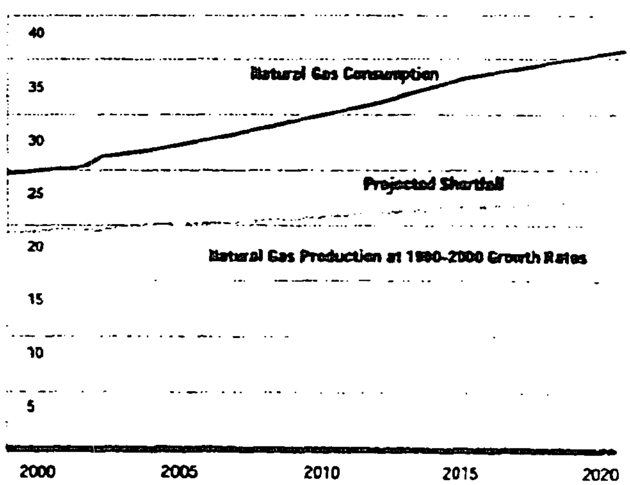
Over the next 20 years, U.S. oil consumption will grow by over 6 million barrels per day. If U.S. oil production follows the same historical pattern of the last 10 years, it will decline by 1.5 million barrels per day. To meet U.S. oil demand, oil and product imports would have to grow by a combined 7.5 million barrels per day. In 2020, U.S. oil production would supply less than 30 percent of U.S. oil needs.

Sources: *Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.*

Figure 3

U.S. Natural Gas Consumption Is Outpacing Production

(Trillion Cubic Feet)



Over the next 20 years, U.S. natural gas consumption will grow by over 50 percent. At the same time, U.S. natural gas production will grow by only 14 percent, if it grows at the rate of the last 10 years.

Sources: *Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.*

We have a similar opportunity to increase our supplies of electricity. To meet projected demand over the next two decades, America must have in place between 1,300 and 1,900 new electric plants. Much of this new generation will be fueled by natural gas. However, existing and new technologies offer us the opportunity to expand nuclear generation as well. Nuclear power today accounts for 20 percent of our country's electricity. This power source, which causes no greenhouse gas emissions, can play an expanding part in our energy future.

The recommendations of this report address the energy challenges facing America. Taken together, they offer the thorough and responsible energy plan our nation has long needed.

Components of the National Energy Policy

The National Energy Policy we propose follows three basic principles:

- The Policy is a long-term, comprehensive strategy. Our energy crisis has been years in the making, and will take years to put fully behind us.
- The Policy will advance new, environmentally friendly technologies to increase energy supplies and encourage cleaner, more efficient energy use.
- The Policy seeks to raise the living standards of the American people, recognizing that to do so our country must fully integrate its energy, environmental, and economic policies.

Applying these principles, we urge action to meet five specific national goals. America must modernize conservation, modernize our energy infrastructure, increase energy supplies, accelerate the protection and improvement of the environment, and increase our nation's energy security.

Modernize Conservation

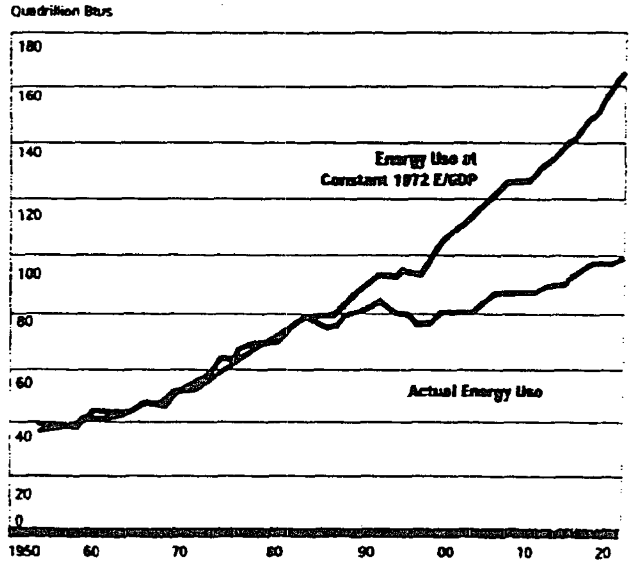
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology – raising productivity, reducing waste, and trimming costs. In addition, it holds out great hope for improving the quality of the environment. American families, communities, and businesses all depend upon reliable and affordable energy services for their well being and safety. From transportation to communication, from air conditioning to lighting, energy is critical to nearly everything we do in life and work. Public policy can and should encourage energy conservation.

Over the past three decades, America has made impressive gains in energy efficiency. Today's automobiles, for example, use about 60 percent of the gasoline they

"Here we aim to continue a path of uninterrupted progress in many fields... New technologies are proving that we can save energy without sacrificing our standard of living. And we're going to encourage it in every way possible."

— Vice President Richard B. Cheney

Figure 4
U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

did in 1972, while new refrigerators require just one-third the electricity they did 30 years ago. As a result, since 1973, the U.S. economy has grown by 126 percent, while energy use has increased by only 30 percent. In the 1990s alone, manufacturing output expanded by 41 percent, while industrial electricity consumption grew by only 11 percent. We must build on this progress and strengthen America's commitment to energy efficiency and conservation.

The National Energy Policy builds on our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Direct federal agencies to take appropriate actions to responsibly conserve energy use at their facilities, especially during periods of peak demand in regions where electricity shortages are possible, and to report to the President on actions taken.
- Increase funding for renewable energy and energy efficiency research and development programs that are performance-based and cost-shared.
- Create an income tax credit for the purchase of hybrid and fuel cell vehicles to promote fuel-efficient vehicles.
- Extend the Department of Energy's "Energy Star" efficiency program to include schools, retail buildings, health care facilities, and homes and extend the "Energy Star" labeling program to additional products and appliances.
- Fund the federal government's Intelligent Transportation Systems program, the fuel cell powered transit bus program, and the Clean Buses program.
- Provide a tax incentive and streamline permitting to accelerate the development of clean Combined Heat and Power technology.
- Direct the Secretary of Transportation to review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration to the National Academy of Sciences study of CAFE standards to be released in July, 2001.

"For the electricity we need, we must be ambitious. Transmission grids stand in need of repair, upgrading, and expansion. . . . If we put these connections in place, we'll go a long way toward avoiding future blackouts."

— Vice President Richard B. Cheney

Modernize Our Energy Infrastructure

The energy we use passes through a vast nationwide network of generating facilities, transmission lines, pipelines, and refineries that converts raw resources into usable fuel and power. That system is deteriorating, and is now strained to capacity.

One reason for this is government regulation, often excessive and redundant. Regulation is needed in such a complex field, but it has become overly burdensome. Regulatory hurdles, delays in issuing permits, and economic uncertainty are limiting investment in new facilities, making our energy markets more vulnerable to transmission bottlenecks, price spikes and supply disruptions. America needs more environmentally-sound energy projects to connect supply sources to growing markets and to deliver energy to homes and business.

To reduce the incidence of electricity blackouts, we must greatly enhance our ability to transmit electric power between geographic regions, that is, sending power to where it is needed from where it is produced. Most of America's transmission lines, substations, and transformers were built when utilities were tightly regulated and provided service only within their assigned regions. The system is simply unequipped for large-scale swapping of power in the highly competitive market of the 21st century.

The National Energy Policy will modernize and expand our energy infrastructure in order to ensure that energy supplies can be safely, reliably, and affordably transported to homes and businesses. This report includes recommendations to:

- Direct agencies to improve pipeline safety and expedite pipeline permitting.
- Issue an Executive Order directing federal agencies to expedite permits and coordinate federal, state, and local actions necessary for energy-related project approvals on a national basis

in an environmentally sound manner, and establish an interagency task force chaired by the Council on Environmental Quality. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state and local permitting activity in particular regions where increased activity is expected.

- Grant authority to obtain rights-of-way for electricity transmission lines with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines and highways.
- Enact comprehensive electricity legislation that promotes competition, encourages new generation, protects consumers, enhances reliability, and promotes renewable energy.
- Implement administrative and regulatory changes to improve the reliability of the interstate transmission system and enact legislation to provide for enforcement of electricity reliability standards.
- Expand the Energy Department's research and development on transmission reliability and superconductivity.

Increase Energy Supplies

A primary goal of the National Energy Policy is to add supply from diverse sources. This means domestic oil, gas, and coal. It also means hydropower and nuclear power. And it means making greater use of non-hydro renewable sources now available.

One aspect of the present crisis is an increased dependence, not only on foreign oil, but on a narrow range of energy options. For example, about 90 percent of all new electricity plants currently under construction will be fueled by natural gas. While natural gas has many advantages, an over-reliance on any one fuel source leaves consumers vulnerable to price spikes and supply disruptions. There are several other fuel sources available that can help meet our needs.

Currently, the U.S. has enough coal to last for another 250 years. Yet very few coal-powered electric plants are now under construction. Research into clean coal technologies may increase the attractiveness of coal as a source for new generation plants.

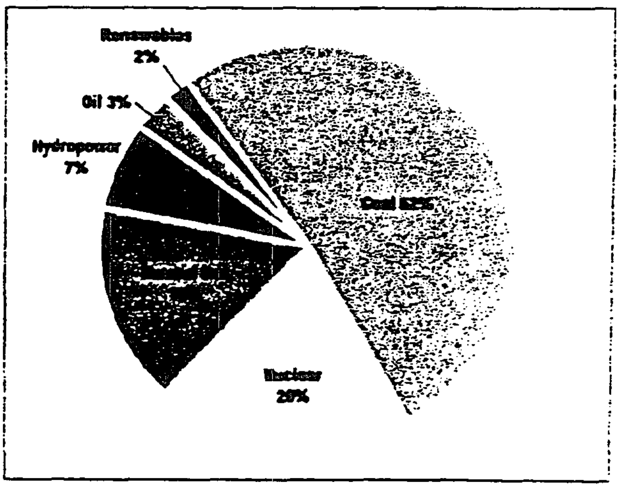
Nuclear power plants serve millions of American homes and businesses, have a dependable record for safety and efficiency, and discharge no greenhouse gases into the atmosphere. As noted earlier, these facilities currently generate 20 percent of all electricity in America, and more than 40 percent of electricity generated in 10 states in the Northeast, South, and Midwest. Other nations, such as Japan and France, generate a much higher percentage of their electricity from nuclear power. Yet the number of nuclear plants in America is actually projected to decline in coming years, as old plants close and none are built to replace them.

Enormous advances in technology have made oil and natural gas exploration and production both more efficient and more environmentally sound. Better technology means fewer rigs, more accurate drilling, greater resource recovery and envi-

"As a country, we have demanded more and more energy. But we have not brought on line the supplies needed to meet that demand.... We can explore for energy, we can produce energy and use it, and we can do so with a decent regard for the natural environment."

—Vice President
Richard B. Cheney

Figure 5
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for nearly 75 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration ronmentally friendly exploration. Drilling pads are 80 percent smaller than a generation ago. High-tech drilling allows us to access supplies five to six miles away from a single compact drilling site, leaving sensitive wetlands and wildlife habitats undisturbed. Yet the current regulatory structure fails to take sufficient account of these extraordinary advances, excessively restricting the environmentally safe production of energy from many known sources.

Our policy will increase and diversify our nation's sources of traditional and alternative fuels in order to furnish families and businesses with reliable and affordable energy, to enhance national security, and to improve the environment. This report includes recommendations to:

- Issue an Executive Order directing all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies a detailed statement on the energy impact of the proposed action.
- Open a small fraction of the Arctic National Wildlife Refuge to environmentally regulated exploration and production using leading-edge technology. Examine the potential for the regulated increase in oil and natural gas development on other federal lands.
- Earmark $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR to fund research into alternative and renewable energy resources – including wind, solar, biomass, and geothermal.
- Enact legislation to expand existing alternative fuels tax incentives to include landfills that capture methane gas emissions for electricity generation and to electricity produced from wind and biomass. Extend the number of eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources.
- Provide $2 billion over 10 years to fund clean coal technology research and a new credit for electricity produced from biomass co-fired with coal.
- Direct federal agencies to streamline the hydropower relicensing process with proper regard given to environmental factors.
- Provide for the safe expansion of nuclear energy by establishing a national repository for nuclear waste, and by streamlining the licensing of nuclear power plants.

"We will insist on protecting and enhancing the environment, showing consideration for the air and natural lands and watersheds of our country."

— Vice President Richard B. Cheney

Accelerate Protection and Improvement of the Environment

America's commitment to environmental protection runs deep. We are all aware of past excesses in our use of the natural world and its resources. No one wishes to see them repeated. In the 21st century, the ethic of good stewardship is well established in American life and law.

We do not accept the false choice between environmental protection and energy production. An integrated approach to policy can yield a cleaner environment, a stronger economy, and a sufficient supply of energy for our future. The primary reason for that has been steady advances in the technology of locating, producing, and using energy. Since 1970, emissions of key air emissions are down 31 percent. Cars today emit 85 percent less carbon monoxide than 30 years ago. Lead emissions are down 90 percent. Lead levels in ambient air today are 98 percent lower than they were in 1970. America is using more, and polluting less.

One of the factors harming the environment today is the very lack of a comprehensive, long-term national energy policy. States confronting blackouts must take desperate measures, often at the expense of environmental standards, requesting waivers of environmental rules, and delaying the implementation of anti-pollution efforts. Shortfalls in electricity generating capacity and short-sighted policies have blocked construction of new, cleaner plants, leaving no choice but to rely on older, inefficient plants to meet demand. The increased use of emergency power sources, such as diesel generators, results in greater air pollution.

New anti-pollution technologies hold great promise for the environment. The same can be said of 21st century power generators that must soon replace older models: significant new resources for land conservation efforts; and continued research into renewable energy sources. All have a place in the National Energy Policy.

The National Energy Policy will build upon our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Enact "multi-pollutant" legislation to establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators.
- Increase exports of environmentally friendly, market-ready U.S. technologies that generate a clean environment and increase energy efficiency.
- Establish a new "Royalties Conservation Fund" and earmark royalties from new, clean oil and gas exploration in ANWR to fund land conservation efforts.
- Implement new guidelines to reduce truck idling emissions at truck stops.

Increase Energy Security.

The National Energy Policy seeks to lessen the impact on Americans of energy price volatility and supply uncertainty. Such uncertainty increases as we reduce America's dependence on foreign sources of energy. At the same time, however, we recognize that a significant percentage of our resources will come from overseas. Energy security must be a priority of U.S. trade and foreign policy.

We must look beyond our borders and restore America's credibility with overseas suppliers. In addition, we must build strong relationships with energy-producing nations in our own hemisphere, improving the outlook for trade, investment, and reliable supplies.

Energy security also requires preparing our nation for supply emergencies, and assisting low-income Americans who are most vulnerable in times of supply disruption, price spikes, and extreme weather.

To ensure energy security for our nation and its families, our report includes these recommendations:

- Dedicate new funds to the Low Income Home Energy Assistance Program by funneling a portion of oil and gas royalty payments to LIHEAP when oil and natural gas prices exceed a certain amount.
- Double funding for the Department of Energy's Weatherization Assistance Program, increasing funding by $1.4 billion over 10 years.
- Direct the Federal Emergency Management Administration to prepare for potential energy-related emergencies.
- Support a North American Energy Framework to expand and accelerate cross-border energy investment, oil and gas pipelines, and electricity grid connections by streamlining and expediting permitting procedures with Mexico and Canada. Direct federal agencies to expedite necessary permits for a gas pipeline route from Alaska to the lower 48 states.

Looking Toward the Future

The President's goal of reliable, affordable, and environmentally sound energy supplies will not be reached overnight. It will call forth innovations in science, research, and engineering. It will require time and the best efforts of leaders in both political parties. It will require also that we deal with the facts as they are, meeting serious problems in a serious way. The complacency of the past decade must now give way to swift but well-considered action.

Present trends are not encouraging, but they are not immutable. They are among today's most urgent challenges, and well within our power to overcome. Our country has met many great tests. Some have imposed extreme hardship and sacrifice. Others have demanded only resolve, ingenuity, and clarity of purpose. Such is the case with energy today.

We submit these recommendations with optimism. We believe that the tasks ahead, while great, are achievable. The energy crisis is a call to put to good use the resources around us, and the talents within us. It summons the best of America, and offers the best of rewards – in new jobs, a healthier environment, a stronger economy, and a brighter future for our people.

"The goals of this strategy are clear: to ensure a steady supply of affordable energy for America's homes and businesses and industries."

— President George W. Bush

Transmission via Facsimile

OFFICE OF THE VICE PRESIDENT

Phone: ~~(202) 456-9000~~ Fax: ~~(202) 456-6212~~

Date: 4/2/01 **Time:** 6:00pm

To: Joseph T. Kelliher

Fax Number: 202-586-7210

From: Chris Covert - Energy Policy Taskforce Intern

Number of Pages, Including Cover Sheet: 9

Message: Mr. Kelliher

Chris C.

ASSOCIATION OF AMERICAN RAILROADS
50 F STREET, N.W.
WASHINGTON, D.C. 20001

Edward R. Hamberger
President and Chief Executive Officer

Telephone: (202) 639-2400
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March 23, 2001

The Honorable Dick Cheney
The White House
Washington, DC 20500

Dear Mr. Vice President:

I am writing to you in your capacity as chairman of the White House Energy Policy Development Task Force. The Association of American Railroads (AAR) appreciates this opportunity to offer its observations on the impact of higher energy prices on the nation's rail sector.

I would note that AAR's comments are intended to supplement the briefing papers submitted to you earlier by the Coal-Based Generation Stakeholders group of which the railroads are leading members. Some 52 percent of our nation's electricity is generated by coal (with more than two-thirds of that coal transported by rail) and coal is one of the nation's least expensive sources of electrical energy.

In developing an effective energy strategy, it is important to remember that America -- at least until recently -- has enjoyed some of the lowest energy prices in the world. These low energy costs have enhanced our competitive position in all sectors of trade from agriculture to manufacturing.

Railroads applaud the Bush administration's efforts to develop a national energy strategy, and we commend you for personally taking on the responsibility for this effort. Energy improvements will contribute to the industry's bottom line due to both lower diesel fuel costs as well as their impact on railroad customers. These customers range from automobile manufacturers whose products can be affected by higher fuel prices to electric utility customers for whom railroads ship millions of tons of coal each year.

23603

Despite the fact that railroads are three times more fuel efficient than trucks, the price of diesel fuel continues to be a major challenge for the rail industry. In providing cost and energy efficient freight service, U.S. freight railroads consume huge volumes of diesel fuel – over four billion gallons annually. Because the cost of fuel is a major cost component of railroad operations – comprising 7.1 percent of industry costs – the alarming jump in fuel prices over recent periods has been a substantial hardship for railroads and their customers.

The price of railroad fuel toward the end of 2000 was the highest during the past 20 years, and likely the highest ever. As of the end of 2000, the average price paid by railroads for diesel fuel had rocketed to a level 239 percent of the price at the beginning of 1999. Long term contracts and customer agreements often limit the ability of railroads to recover major cost increases in a timely fashion. Thus, railroads are being forced to expend an additional $2.4 billion annually or $6.6 million more each and every day. Moreover, because this huge increase in costs is required to perform exactly the same level of service, these increased costs have a direct impact on the industry's financial bottom line. In fact, they represent an amount equal to three-quarters of industry net income.

Looking ahead, future pricing policies will have to include major price increases to recover lost profitability as a result of fuel cost increases. Some shippers have indicated that they will be unable to absorb these transportation rate increases and will be forced to pass the expense on to their customers.

Because railroads have huge fixed costs to cover, it makes economic sense to move traffic that is marginally profitable (i.e., railroads handle traffic that is slightly above variable cost because it contributes to fixed cost). However, the fuel cost increases have raised our variable costs to such a degree that, in some segments, variable costs are becoming higher than the revenue, and traffic that has been historically profitable may have to be eliminated.

Moreover, higher energy prices are having a negative effect on some freight shippers, a development that affects freight railroads indirectly. For instance, eight of the ten major aluminum producers served by one leading railroad are currently shut down, and the remaining two are operating at 50 percent capacity. Instead of producing product, these companies are selling their allotted power.

Other railroads report that dramatically higher natural gas prices have led to significant traffic losses due to reductions in production and plant closures in areas such as plastics, cement, fertilizer, and intermediate gases such as propane and butane.

For these reasons, AAR encourages you to take strong and immediate action to formulate an effective national energy strategy. In addition to urging support for actions

23604

to reduce energy prices and for the positions of the Coal-Based Generation Stakeholders group, I am pleased to enclose AAR briefing papers on the following three railroad priorities: repeal of the 4.3 cent per gallon "deficit reduction" diesel fuel tax, an acceptable resolution of the coal mine valley fill issue, and establishment of a locomotive fuel efficiency program within the Department of Energy.

AAR looks forward to working with you and the other members of the Energy Policy Development Task Force to craft a balanced and effective energy policy for our nation.

Sincerely,

Ed

Edward R. Hamberger

cc: The Honorable Norman Mineta
The Honorable Spencer Abraham
Mr. Lawrence Lindsey
Mr. Andrew Lundquist
Ms. Karen Knutson
Mr. John Frenzel

Repeal Deficit Reduction Fuel Taxes

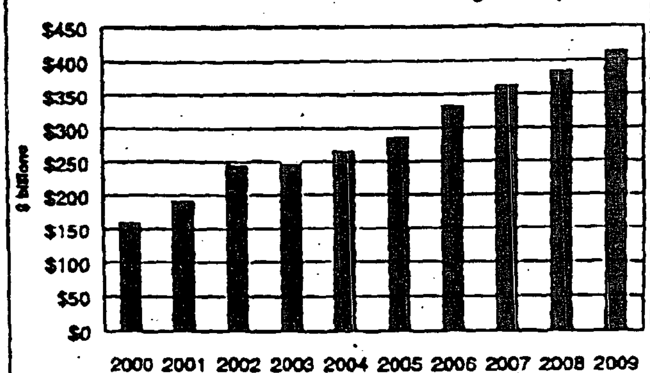
AAR supports S. 820 and H.R. 1001 that would repeal deficit reduction fuel taxes paid by railroads and barges. AAR opposes H.R. 2060 that would create a railroad trust fund from deficit reduction fuel taxes.

Inequitable Taxation in a Surplus Environment

The railroad and inland barge industries pay a 4.3 cents per gallon deficit reduction fuel tax even though there is no longer a federal deficit. Furthermore, the railroad and inland barge industries are required to pay deficit reduction fuel taxes while their competitors, the truckers, do not.

Among all U.S. industries, only transportation industries have been obligated to pay special deficit reduction fuel taxes, and today, among the different transportation modes, only railroad and barge companies continue to pay such a tax. The deficit reduction fuel tax rate has varied over time, and currently stands at 4.3 cents per gallon on diesel fuel consumed. Since inception of the tax in 1990, freight railroads have paid over $1.4 billion in deficit reduction fuel taxes. Railroads continue to pay these taxes even though there is no longer a federal deficit.

CBO Estimated Baseline Annual Budget Surplus



Source: CBO, *The Economic and Budget Outlook: An Update* (July 1999)

Trucking companies, direct competitors of railroads and barge companies, do not pay a deficit reduction fuel tax. The entire revenue from the taxes paid by the truckers is paid into the Highway Trust Fund, and is used to pay for improvements and maintenance of highway infrastructure. Therefore, while railroads continue to contribute to a non-existent deficit, the truckers contribute to their own infrastructure improvement.

By contrast, the railroad industry does not have a trust fund but privately funds its own maintained rights-of-way. In 1998, freight railroads spent $7.7 billion maintaining and improving their own infrastructure. This is equivalent to a tax of $2.13 per gallon of fuel consumed by railway locomotives — an amount, which is four to ten times the equivalent of tax paid by the competing modes of transportation.

Both the House and Senate 1999 tax cut bills, acknowledged the tax inequity and included a repeal of the 4.3 cent deficit reduction fuel tax for the railroad and barge industries, but the final 1999 tax cut bill was vetoed by President Clinton for reasons other than the railroad tax repeal.

Support for an Equitable Solution

The railroads are not alone in calling for a fair and equitable solution to the current deficit reduction fuel tax problem. The U.S. Chamber of Commerce and the American Road and Transportation Builders Association (ARTBA) have adopted policies in support of repealing the 4.3-cent deficit reduction fuel tax. Numerous agriculture groups including the American Farm Bureau Federation, American Soybean Association, National Association of Wheat Growers, and the National Corn Growers Association are also on record supporting the repeal of this tax.

Railroad Trust Fund Proposals

AAR opposes H.R. 2060, the Railway Safety and Funding Equity Act of 1999 (RSAFE), a bill that would transfer the 4.3-cent deficit reduction fuel tax into a new Railroad Trust Fund for highway-rail grade crossing safety programs. H.R. 2060 would divert significant railroad resources to help solve what is fundamentally a highway safety problem. Not only is this proposed cross subsidy of highway needs by the railroads bad public policy, but these railroad fuel tax revenues are needed to meet significant railroad infrastructure needs.

AAR also opposes any effort to use the 4.3 cents per gallon deficit reduction fuel tax paid by the railroads to create a Railroad Trust Fund to finance short-line/regional railroad improvements, intercity or commuter passenger rail needs, or other purposes. In these scenarios, the beneficiaries of the funds, while having contributed little or nothing, would profit from a cross-subsidy from the large freight railroads. It is not appropriate to expect the large railroads to provide additional funding support for passenger rail, short-lines, or highway-rail traffic control devices. Neither do large railroads care to finance their own infrastructure needs through a Railroad Trust Fund by inefficiently sending funds to Washington, DC, simply to be returned to private sector railroads, minus bureaucratic administrative and overhead costs, and subject to political manipulation and government regulatory red tape.

Summary

The railroads' true advantage in cost, environmental impact, reduced highway damage and congestion, safety, and fuel efficiency rightfully have become important criteria in a modal choice. Artificial cost barriers to the use of freight transportation, in terms of inequitable deficit reduction taxes, can only disadvantage rail in the competitive marketplace and distort consumer choice.

23607

AAR supports S. 820 and H.R. 1001 that would repeal the 4.3 cents per gallon deficit reduction fuel tax for the railroads and barges. This tax should be repealed because it is:

1. Discriminatory against railroads, since the trucking industry pays no deficit reduction fuel tax;

2. Economically unsound, because it artificially diverts traffic that other wise would travel by rail; and

3. Inconsistent with national policy, because it violates the goals of economy, impartiality, energy efficiency, and environmental friendliness.

Additionally, large freight railroads oppose the transfer of these revenues to a federal Railroad Trust Fund or any other form of a transportation trust fund.

THE COAL MINE VALLEY FILL ISSUE

DESCRIPTION: In October 1999, a federal district court in West Virginia stunned the Nation's coal industry with a decision barring the longstanding practice of building valley and hollow fills to store the dirt and rock generated during coal mining. *Bragg v. Robertson*, 72 F. Supp. 2d 642 (S.D. W.Va. 1999), *appeal pending*, No. 99-2443 (4th Cir). Notwithstanding the fact that these engineered fill structures are both a necessary part of coal mining operations and expressly authorized by federal laws regulating coal mining, the court interpreted regulations issued under those laws as prohibiting their construction in hollows and valleys that inevitably contain stream courses. While the decision remains pending on appeal, the past Administration abandoned the working men and women of America's coal industry and announced that it now agreed with the court's view. The past Administration's action in this regard is not only contrary to the laws it administers, it will have economic consequences in West Virginia alone that a Marshall University study concluded will be "as great or greater than those of the Great Depression." Earlier in the same litigation, the federal agencies (EPA, OSM & COE) settled the claims related to the use of section 404 permits to authorize these fills under the Clean Water Act. The agencies agreed to conduct a programmatic Environmental Impact Statement which addresses environmental and economic consequences of different actions, as well as evaluate the better coordination of overlapping regulatory programs.

STATUS: The appeal in the 4th Circuit has been briefed and was argued on December 7, 2000. In the meantime, the EPA, OSM and COE are preparing a Draft EIS. EPA and COE also have pending a proposed rule published on April 20, 2000 clarifying that excess spoil is fill material subject to section 404 and not section 402 of the CWA. This rule would remove the ambiguity in the agencies' programs that the district court relied on to reach its erroneous conclusion that these fills as well as other activities that have the effect of replacing waters of the United States are not authorized by section 404.

KEY DECISIONS: Should any part or form of a Draft EIS be publicly released before the completion of the underlying technical, economic and other studies?
OPTIONS: * Delay public release of Draft EIS in any form until all the underlying studies are complete and have been subject to some form of peer review. This option is completely defensible and will assure that the EIS process on this matter will not be subject to criticisms related to its credibility and integrity.

*Allow the agencies to release an executive summary or other form of a draft EIS that purports to provide an overview of the current analysis of complex technical questions. This option will appease few and invite strong criticism from industry and, perhaps, the West Virginia state legislature that has funded part of the studies.

KEY DECISIONS: Whether EPA and COE should adopt as a final rule the proposal clarifying the scope of the section 404 program with respect to excess spoil and other activities that have the effect of replacing waters of the United States.
OPTIONS: * Proceed to adopt as final the proposed rule published on April 20, 2000. The rule is an important part of maintaining the integrity of the 404 program by clarifying a longstanding ambiguity that has caused grave uncertainty for the regulated community and the agencies. It not only addresses the excess spoil issue but other activities as well, e.g. landfills.

* Await the decision of the 4th Circuit to determine whether it would require any modification of the proposal to address the central features of the rule. At some point, the EIS on mountaintop mining will have to analyze how excess spoil fills are to be addressed within the prevailing regulatory schemes under the CWA and SMCRA and whether any conflicts exist.

Public-Private Fuel Efficiency and Emissions Partnerships

WHAT SHOULD BE DONE?	**Establish a public-private partnership involving the federal government, railroads, and railroad suppliers designed to increase the fuel efficiency of, and reduce emissions from, diesel locomotives. The partnership should be similar to the "21st Century Truck Initiative" now underway.**
WHY?	**The partnership would encourage conservation of natural resources and reduced emissions by the nation's largest freight transportation provider. Moreover, the "21st Century Truck Initiative" will use hundreds of millions of dollars of federal funds to sharply increase fuel efficiency and lower emissions for motor carriers that compete against railroads. Equity demands that railroads receive the same support.**

ISSUE OVERVIEW

In April 2000, the Clinton Administration announced the creation of the "21st Century Truck Initiative," a public-private research partnership involving many of the nation's largest heavy-duty engine and truck companies; the U.S. Departments of Defense, Energy, and Transportation; and the Environmental Protection Agency.

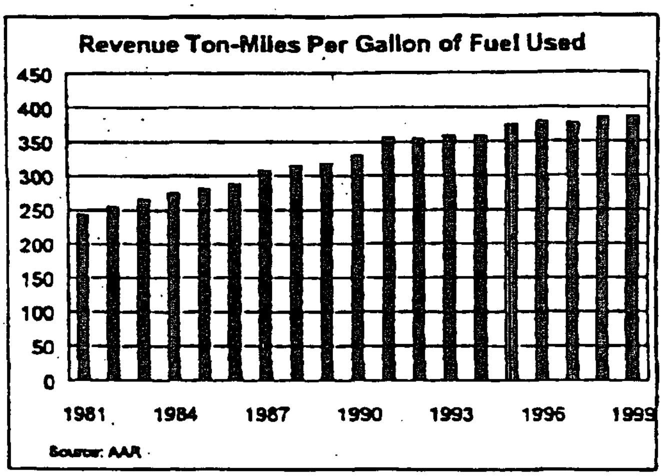
The goals of the Truck Initiative include developing truck and bus technologies that increase fuel economy, improve safety, reduce emissions, and lower costs. The partnership is designed to lead, within 10 years, to prototypes that double existing fuel economy for long-haul trucks and significantly reduce truck emissions of nitrous oxide, particulates, and other air pollutants.

Because of the Truck Initiative, the fiscal year 2001 budget saw an increase of $31 million in truck research spending to a total of $137 million.

Railroads account for more than 40 percent of the nation's freight ton-miles, considerably more than trucks' 29 percent share. Therefore, increases in rail fuel efficiency would significantly benefit our economy and environment. However, there is no public-private program involving railroad locomotives similar to the Truck Initiative. Instead, railroads and their suppliers must fund research and development efforts aimed at increasing fuel efficiency and reducing emissions on their own. For example, the Burlington Northern and Santa Fe Railway and the Union Pacific Railroad are spending more than $1 million apiece on these issues, while the Association of American Railroads is funding an industry-wide emissions research program.

JUSTIFICATION FOR DESIRED POLICY

- A federal program to increase fuel efficiency and reduce emissions from diesel locomotives will provide public benefits to the environment similar to those of the 21st Century Truck Initiative.
- By providing motor carriers a major federal subsidy through the Truck Initiative, the federal government will artificially reduce motor carrier costs. This imbalance between trucks and railroads will encourage shippers to use trucks, even where railroads provide more efficient services.
- The U.S. Department of Transportation's *Moving America: New Directions, New Opportunities — A Statement of National Transportation Policy* notes that "Federal programs and policies must treat modes and carriers fairly." This condition is clearly violated if motor carriers receive federal benefits not made available to their competitors.
- A federal program will magnify the substantial strides in both fuel efficiency and emissions control already accomplished by the railroads. Railroad fuel efficiency is up 16 percent since 1990 and 58 percent since 1980. Railroads are also committed to substantial reductions in atmospheric emissions, having endorsed an EPA proposal that calls for a 60 percent reduction in nitrogen oxide emissions from locomotives manufactured beginning in 2005. With federal support, the railroad industry can build on its own voluntary achievements and foster improved conservation and emissions control.



From: Ball, Crystal A - KN-DC [mailto:caball@bpa.gov]
Sent: Friday, March 23, 2001 12:35 PM
To: Anderson, Margot; Carrier, Paul
Cc: Stier, Jeffrey K - KN-DC; Seifert, Roger - KN-DC
Subject: RE: BPA DSI information
Importance: High

Please use the revised one-page summary.

Thanks!

> <<DSI paul info.doc>> <<McCook pr final.doc>>

National Environmental Strategies

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Washington DC 20037
(202) 333-2524
Fax: (202) 338-5950

FAX TRANSMISSION COVER SHEET

Date:	*April 18, 2001*
To:	*Joe Kelliher*
Fax:	*586-7210*
Re :	*Mercury Document for Meeting w/Steve Griles, Marc Himmelstein, et. al.*
Sender:	*Holly Hopkins*

YOU SHOULD RECEIVE 2 PAGES, INCLUDING THIS COVER SHEET. IF YOU DO NOT RECEIVE ALL THE PAGES, PLEASE CALL (202) 333-2524.

Please note attached.

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Resolution of EPA Mercury Regulatory Determination

Problem: On December 14, 2000, EPA issued a "regulatory determination" under the Clean Air Act (CAA) that regulation of mercury and possibly other hazardous air pollutants (HAPs) is "appropriate and necessary" for coal- and oil-based power plants. This decision automatically triggers a formal rulemaking. EPA is scheduled to issue a proposed rule in late 2003, a final rule in late 2004, and to require compliance by late 2007. Because of the specific language EPA used in the regulatory determination, the pending rulemaking *must* result in the imposition of "maximum achievable control technology" (MACT) standards for mercury and possibly other HAPs. Effective immediately, before EPA has determined through rulemaking what level of control should be required on a national basis, new and reconstructed plants *must* undergo case-by-case MACT review for mercury and other HAPs.

Status: The utility industry has filed a Petition for Review in the D.C. Circuit. The industry is *not* challenging the basic decision to regulate mercury emissions, but just the two MACT-related issues. On April 9, EPA filed a motion arguing the court has no jurisdiction to review these issues because the agency's decision has "no regulatory impact." The utility industry also has filed an administrative petition with EPA, requesting the reconsideration of that portion of the regulatory determination that prescribes a MACT program and immediately impacts new and reconstructed plants. EPA has not yet responded to this petition.

Implications: EPA's announcement is inconsistent with national energy policy objectives because it will limit fuel choices, impede the construction of new power plants during the next four years, and increase the cost of electricity. Several studies have estimated mercury control costs of $5 - $15 billion annually. In addition, recent analysis shows that the MACT program contemplated by the regulatory determination would impact utilities in the same manner as a Kyoto-type CO_2 program, in that it would cause significant fuel switching from coal to natural gas (50 percent decline in coal use in 2020).

Possible Resolution: EPA's regulatory determination should be modified to remove the legal bias in favor of a MACT requirement and to clarify that the agency intends to consider all available regulatory and policy options during the pending mercury rulemaking. This could be accomplished through a brief *Federal Register* notice issued within the next two months to ensure that (1) no new planned electricity generation is impeded by the case-by-case MACT review process; (2) this issue is addressed administratively rather than in court, and (3) the clarification can be explained in the context of the Administration's energy policy.

www.eia.doe.gov
Energy Information Administration

Short-Term Energy Outlook

April 2001

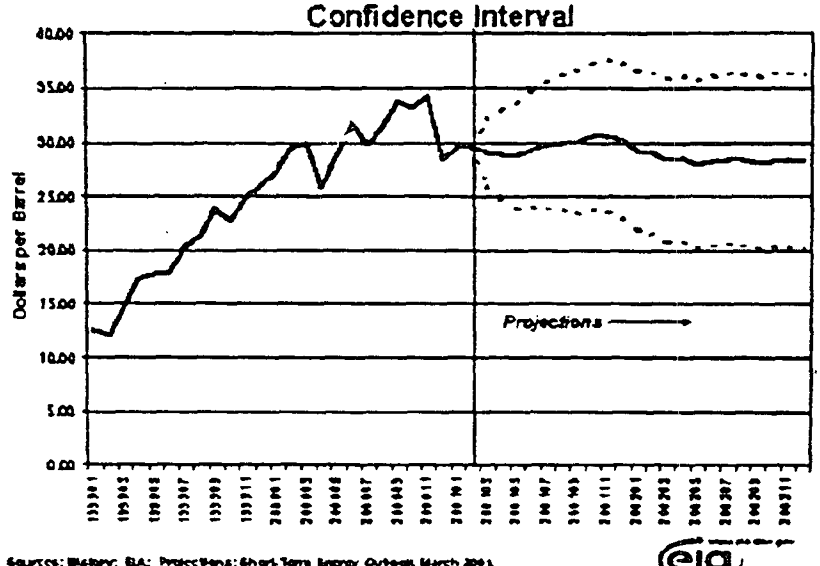


Figure 1. WTI Crude Oil Price: Base Case and 95% Confidence Interval

Overview

U.S. economic growth assumptions have been lowered for this edition of the Outlook from last month's report, resulting in somewhat weaker expected growth in U.S. energy consumption. We now expect U.S. real GDP to advance at about 2.2 percent in 2001 instead of the 2.6 percent projected in February. A result of the downward revision in projected growth this year is a slightly more rapid rebound in 2002 but overall levels of economic activity are lower throughout the projection period. Oil demand in the United States and other consuming regions is now seen as to increase less rapidly in 2001 than projected previously. We have adjusted global oil demand growth for this year downward to 1.5 million barrels per day from the 1.6 million barrels per day indicated last month. This results in projected world demand levels of 77.2 million barrels per day in 2001 and 78.9 million barrels per day in 2002. Cumulatively, we have lowered the world demand total expected for 2001 by 700,000 barrels per day from the level projected three months ago.

Despite the lower demand outlook, industrialized country oil stocks continue to fall below expectations, effectively offsetting most if not all of any resulting downward pressure on prices relative to the levels indicated in our previous Outlook. Thus, we see the U.S. refiner cost of crude oil likely to average around $26.60 per barrel this year compared to $27.70 per barrel in 2000. Our view of the world oil balance suggests that significant improvement in the inventory situation (on a seasonally adjusted basis) over the next 21 months is rather unlikely, so prices are likely to remain relatively high through 2002 (Figure 1). A more severe slowdown in economic growth in consuming countries than we are allowing for in our base case could alter the price outlook significantly. We have evaluated in some detail the sort of overall demand impacts in the United States that could be expected under a very low short-term growth scenario. In such a case, U.S. oil demand growth could be reduced by as much as 150,000 - 200,000 barrels per day relative to the base case. Reverberations worldwide from such a development would be expected to generate additional reductions in demand elsewhere in 2001 or 2002.

The U.S. natural gas supply picture seemed to brighten a little last month as average storage withdrawals during the month were below normal and below previous expectations. However, even if only modest withdrawals are required this month, we are still likely to end the heating season with the total level of gas in storage below the previous low recorded by EIA. In our view, only a spectacular performance from the U.S. and Canadian gas industry in terms of increased production or an extremely mild summer this year would generate much in the way of additional reductions in natural gas prices beyond what has already happened since mid winter. As we currently expect working gas to reach 689 billion cubic feet at end-March, seasonal injections of 2,310 billion cubic feet would be required from April through October to reach 3 trillion cubic feet (the approximate average end-October level between 1995 and 1999) before the next heating season. That kind of build would be about 500 billion cubic feet (25 percent) above average (1995-1999). Consequently we expect the industry to fall well short. Average monthly gas spot prices below $4 per thousand cubic feet between now and next winter are possible but do not seem very likely under these circumstances.

More good news for Northeast heating oil customers arrived since last month. Average residential heating oil prices fell to an estimated $1.32 per gallon in February from the $1.37 per gallon seen in January. This was 9 cents below the December average. The winter average is now expected to be $1.36 per gallon, 8 percent below the $1.48 price we projected as recently as January. Household heating oil expenditures for the winter will still be about 27 percent above last year's estimated level, but this is certainly less dramatic than the 40 percent projected in January (Figure 2). Because of strong production and imports and a respite from the kind of abnormally cold weather seen at the beginning of winter, inventories of heating oil are now within the normal range. For natural gas consumers, the expected level of winter expenditures has not changed much. We still expect that the increase in household gas bills over last winter will amount to 70-75 percent (Figure 3).

International

Crude Oil Prices. The monthly average U.S. imported crude oil price in February was about $26 per barrel (almost $30 per barrel for West Texas Intermediate crude oil), about $1 per barrel higher than January's average U.S. imported crude oil price (Figure 1).

Price declines during the past few weeks had indicated weakness in the near-term market. However, EIA believes that the OPEC 10's (OPEC excluding Iraq) decision to cut oil production quotas effective February 1 will provide enough support to maintain world oil prices near current levels. EIA does not believe that further quota cuts are necessary to maintain the OPEC basket oil price (roughly equivalent to the average U.S. imported crude oil price) within OPEC's target range of $22 - $28 per barrel in 2001 and 2002.

International Oil Supply. Although OPEC cut production quotas by 1.5 million barrels per day effective February 1, OPEC has suggested that further cuts could be needed to maintain the OPEC basket price within its desired range. In addition, some OPEC delegates have suggested that further quota cuts may be adopted even if the OPEC basket prices remain within this range, in part because of concerns that a seasonal second quarter decline in demand and a world economic slowdown could weaken the demand for OPEC oil. OPEC Secretary-General Ali Rodriguez was earlier quoted as saying that there was "almost a conviction" among producers for a production cut ahead of a forecasted drop in demand in the second quarter, with the cuts totaling up to 1 million barrels per day.

EIA's assessment does not factor in any further cuts in 2001 because EIA's analysis indicates that the February 1 quotas are sufficient to support OPEC's desired price range. The seasonal decline in demand during the second quarter is seen as a necessary accompaniment to the seasonal stock build normally associated with this time of year. EIA expects that oil stocks in the OECD countries will continue to be tight compared to normal levels and will provide enough support to prevent prices from falling significantly.

Iraqi efforts to end U.N. sanctions have continued to result in lowered exports and production since December. The U.N. reported that reduced Iraqi exports have resulted in a revenue loss of over $2.2 billion or $2.4 billion (euros) to the program since December 2000. Despite these revenue losses, EIA's projections assume that Iraqi efforts to end sanctions will continue in 2001 with negative consequences on Iraqi exports and production (Figure 4). Iraqi production in 2001 is not assumed to exceed the 3 million barrels per day level reached as recently as October 2000.

Non-OPEC production is expected to increase by another 0.7 million barrels per day in 2001, and another 0.9 million barrels per day in 2002. This represents an increase of 100,00 barrels per day from the previous Outlook, with the gain expected primarily from the former Soviet Union.

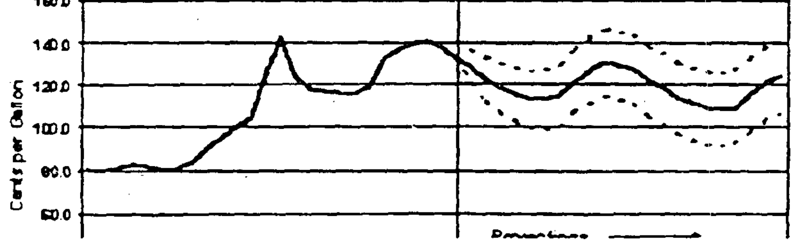
International Oil Demand. World oil demand is expected to continue to grow despite concerns over a gradual economic slowdown in the industrialized countries (Figure 5). However, EIA has lowered its projected world oil demand in 2001 by 100,000 barrels per day from the previous Outlook, reducing world oil demand growth to 1.5 million barrels per day in 2001. Non-OECD Asia is still expected to be the leading region for oil demand growth over the next two years.

World Oil Inventories. EIA does not attempt to estimate oil inventory levels on a global basis, however, the direction global oil inventories are headed is discerned from EIA's world oil supply and demand estimates. These estimates provide only a rough guide because of what has come to be known as the "missing barrels problem". The available limited data for tracking inventories suggest that inventories have not been building as fast as any of the global supply/demand estimates (including EIA's) would indicate, and that the inventory estimates are being overstated.

The most reliable inventory data are from the OECD countries. The data indicates that there was very little stockbuild in 2000 for these countries, which account for a little more than half of total world oil demand (Figure 6). However, EIA's global supply/demand estimates suggest that OECD inventories should have been building by almost 400,000 barrels per day in 2000. EIA's projections for OECD inventories are adjusted to reflect the assumption that the "missing barrels problem" will continue in 2001, but will be diminished by 2002. With this adjustment, OECD inventories are projected to grow relatively slowly in 2001 and 2002. EIA believes that this stock growth will be small enough to provide continued price support because inventories will continue to be low compared to levels required to provide normal coverage for forward demand.

EIA's evaluation of normal OECD stock levels accounts for both historical averages and increasing inventory requirements, reflecting world demand increases. For this reason, EIA's assessments of OECD stocks are more bullish for prices than those using just historical averages.

Figure 7. Residential Heating Oil Prices: Base Case and 95% Confidence Interval



U. S. Energy Prices

Heating Oil. Retail heating oil prices have been sliding down from their winter peak of $1.41 per gallon last December. Our winter heating oil prices are expected to average around $1.36 compared to $1.39 in our previous Outlook.

Nevertheless, retail heating oil prices have been quite high in historical terms. The national average price for the 4th quarter (October-December) of last year was almost 40 cents per gallon above the 1999 4th quarter price (Figure 7). Now that the heating season (October-March) is nearly over, we can be confident that retail heating oil prices have peaked for the winter, provided that no sustained crude oil price shocks occur over the next month. Warmer than normal weather for the first two months of the year accompanied by falling crude oil prices in December (dropping about $5.00 dollars per barrel from November) and January, have helped ease heating oil prices. Because of the relatively mild weather in the Northeast during the last half of January and portions of February, heating oil stock levels have stayed fairly steady over the past two months. For the first time since November 1999, U.S. distillate stocks are currently within bounds of the normal range (Figure 8). Also, heating oil production had been quite vigorous, running several hundred thousand barrels per day over last year's pace.

Motor Gasoline. Pump prices have dropped about 10 cents per gallon since last September, but will soon be heading back up as we enter the driving season in April. With crude oil prices gaining about $1.00 per barrel from their December lows, combined with lower than normal stock levels, we project that prices at the pump will rise to about $1.49 per gallon (for regular unleaded self-service) during the peak months of the driving season (Figure 9). For the summer of 2001, we are projecting an average price of $1.47 per gallon, compared to $1.53 seen during the previous driving season. Even though motor gasoline stocks during the driving season are projected to be slightly lower than they were a year ago (Figure 10), crude oil prices are also projected to be lower. Moreover, last year the high national average prices were skewed by exceedingly high pump prices in the Midwest (over $2.00 per gallon at times), which, in turn, were the result of critical regional supply problems. Although in our base we do not project a repeat of last year, the current situation of relatively low inventories for gasoline could once again set the stage for some regional imbalances in supply that could bring about significant price volatility in the U.S. gasoline market.

Natural Gas. Natural gas prices (Figure 11) began an ascent that originated last summer primarily in response to low levels of underground gas storage. Spot prices have increased well over $4.00 per thousand cubic feet since late June, even topping $10.00 per thousand cubic feet on several occasions this winter. The wellhead price this heating season is likely to end up more than double the price of last heating season. The length of time that gas prices have remained so high is unprecedented. Moreover, the current dynamics of the natural gas market leads us to believe that prices at the wellhead will not soon be returning to the low $2.00 per thousand cubic feet experienced just one year ago. The chief basis for our view is our outlook for robust levels of gas demand growth over the next two years, particularly in the electric power sector. By the year 2002, more than half of the increases in electricity generation are expected to come from natural gas. Furthermore, gas demand in the industrial sector (the single largest gas consuming sector) is also expected to make strong gains over the same time period. Although gas production and imports are expected to increase in the forecast period, we believe that the gains in supply will not be enough to bring the wellhead price down to the $2.00-3.00 range in the short-term.

We expect that winter (October 2000-March 2001) natural gas prices at the wellhead will end up averaging about $5.64 per thousand cubic feet. In our base case, residential prices for natural gas this winter would be about 46 percent higher than last year during that period. When the heating season ends next month, average wellhead prices are projected to decline, averaging about $4.05 per thousand cubic feet for the spring and summer. However, if the summer weather is exceedingly hot in regions that consume large quantities of gas-fired electricity, (California and Texas for example), then injections into underground storage for the next winter would be strained and prices could start rising more sharply and sooner than expected. In 2001, the annual average wellhead price is projected to be about $4.73 per thousand cubic feet. Next year, we expect the storage situation to improve modestly and with that, a decrease in the average annual wellhead price. Increases in production and imports of natural gas needed

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to keep pace with the rapidly growing demand for natural gas will be accompanied, for the time being, by relatively expensive supplies for gas due to rising production costs and capacity constraints on the pipelines.

Electric Utility Fuels. The rapid rise in gas prices last summer and fall has pulled delivered gas prices above heavy fuel oil prices on a cost per Btu basis (Figure 12). As this situation is likely to persist, we anticipate some recovery in the amount of oil used for power generation over the very low levels seen since late 1999. In 2001, the cost of coal to electric utilities is projected to increase slightly, after years of slow but continual decline, as coal, like oil, is being used more intensively for electricity generation lieu of expensive or unavailable natural gas. On an inflation-adjusted basis, however, coal prices should still show a deadline this year.

U.S. Oil Demand

The recent release of December 2000 monthly data confirms the overall shrinkage in last year's petroleum demand that had become increasingly apparent for the past several months. The data for last year show that shipments of petroleum products declined by 30,000 barrels per day despite substantial growth in major economic indicators for much of the year (Figure 13). Despite robust economic growth and the presence of colder-than-normal weather of the fourth quarter, petroleum markets were unable to overcome the effects of a record mild first quarter--the peak heating season--and the substantial increase in energy prices that eroded demand during the second half of the year.

Motor gasoline demand in 2000 fell by almost 50,000 barrels per day, reflecting a fractional decline in highway travel activity brought about by a 30-percent year-to-year increase in retail motor gasoline prices. Although highway travel declined during the third quarter—the peak driving season--from that of the previous year, the lagged effects of the earlier price increases and the moderation in economic growth resulted in an even larger year-over-year contraction in the fourth quarter. Despite a 10-percent hike in ticket prices in 2000, commercial jet fuel demand, buoyed by 6.5- and 4.5-percent increases in utilization and capacity, respectively, rose 3.5 percent. (The resultant 2-percent increase in load factor boosted consumption by constraining fuel-efficiency increases to only one percent, half the long-term average). Total jet fuel deliveries, which include corporate, military, and weather-related components, rose just 2.0 percent, down from 3.1 percent in the previous year. The record mild warm weather of the first quarter depressed shipments of jet fuel used as a blending component during the winter months. Distillate fuel oil demand grew by 3.2 percent in 2000 led mostly by strength in transportation diesel demand. Residual fuel shipments, highly sensitive to changes in relative prices, fluctuated wildly but managed to increase by 1.8 percent for the year as a whole. Following a year of double-digit increases, the combination of slowdowns in petrochemical activity, and mild weather resulted in a slight decline in the total demand for liquefied petroleum gas and oil-based petrochemical products.

During the forecast interval, total petroleum demand is projected to increase once again. Despite the current economic slowdown, growth in real disposable income is projected to be 3.1 percent in 2001, and a robust 4.6 percent in 2002. Petroleum prices, which are expected to decline slowly throughout the forecast interval, will not have the same kind of negative impact on demand this year that was brought about last year by large average price increases. Weather patterns are assumed to exhibit normal seasonality. In this environment, total petroleum demand is projected to increase by 260,000 barrels per day in 2001, accelerating to 443,000 barrels per day next year, a 1.8-percent average increase. Reversing last year's declines, motor gasoline demand and highway travel activity are both expected to increase, but at an average of only 2.2 percent despite the steady downward trend in retail gasoline prices and robust growth in disposable income. Total jet fuel demand is expected to increase by an average 1.6-percent rate, with commercial demand rising by 3 percent. Distillate fuel demand is projected to rise by an average of 2.1 percent, down from the 3-percent average of the previous 2 years, due to a moderation

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in transportation demand. Demand for residual fuel oil is projected to continue to decline throughout the forecast interval, as declines in non-power generation demand offset a modest recovery in shipments to power generators.

U.S. Oil Supply

Average domestic oil production is expected to be flat in 2001, at a level of 5.83 million barrels of oil per day (Figure 14). For 2002, a 0.20 percent rise is expected to result in a production rate of 5.84 million barrels of oil per day average for the year.

In the Lower-48 States, oil production is expected to decline by 53,000 barrels per day to a rate of 4.80 million barrels per day in 2001,and followed by an decrease of 13,000 barrels per day in 2002. Oil production from the Mars, Troika, Ursa, and Brutus Federal Offshore fields is expected to account for about 8.2 percent of the lower-48 oil production by the 4th quarter of 2002.

Alaska is expected to account for about 18 percent of the total U.S. oil production in 2002. Its oil production is expected to increase by 5.6 percent in 2001 and by 2.4 percent in 2002. The gain in 2001 is the result of adding two new satellite fields, Colville River (Alpine) and Prudhoe Bay (Aurora) which contributed to the Alaska North Slope production. Initial rates from Alpine averaged 67,000 barrels per day during January and it is expected to peak at 80,000 barrels per day in mid-2001, while Aurora peak production should occur later in the year. Another satellite field, North Star, is expected to come on in early to mid-2002 and will peak at a rate of 65,000 barrels per day by year's end. A substantial portion of the oil production from Alaska comes from the giant Prudhoe Bay Field. As a result of maintenance, better well work, more development drilling, and better coordination of occasional down time, this field's decline rate last year has changed from the usual 10 percent to only 3 percent per year. However, the field is expected to follow a steeper decline during this forecast period. Oil production from recent discoveries is expected to substantially offset the decline in oil production from the Prudhoe Bay field in the North Slope in 2001. Production from the Kuparuk River field plus like production from West Sak, Tabasco and Tarn fields is expected to stay at an average of 236,000 barrels per day in the 2001-2002 forecast period.

Natural Gas Demand and Supply

U.S. natural gas demand is expected to grow at about a 2.3-percent rate this year, following the strong 4.4-percent performance in 2000 (Figure 15). A slowing economy and less rapid demand growth in the industrial and commercial sectors is the reason. Growth in 2002 is expected to heat up again to about 4.1 percent as the economy picks up again and as new gas-fired power generation requirements continue to mount.

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling experienced over the past year. Production is estimated to have risen by 3.1 percent in 2000 and it is forecast to continue to increase by 3.3 percent rate in 2001 and 2.5 percent in 2002.

According to the American Gas Association (AGA), during the week ending February 23, a total of 101 billion cubic feet (bcf) was withdrawn from storage, bringing the total of working gas to 26 percent full (Figure 16). Based on this information, we estimate that, on an EIA survey basis, working gas in storage at end-February will reach 901 billion cubic feet. From this we project that end-season (March 31) working gas will fall to 689 bcf. This level is more than 100 bcf above last month's projections. While this represents an improvement over previous estimates (and expectations for March spot prices have softened some over the last 2 months) such an end-season level would still represent the lowest recorded by EIA and is 38 percent below the previous 5-year average. We estimate that net injection, between April 1 and October 31, would have to be about 500 bcf (25 percent) above average to bring working gas to average pre-season levels for next winter. We think that only about 60 percent of the extra 500 bcf is likely during the injection season, so that a 200 bcf deficit relative to the 5-year average is likely at end-October.

Net imports of natural gas are projected to rise by about 15 percent in 2001 and by another 4 percent in 2002. For this winter, we expect net imports to be 6.6 percent higher than last winter's imports. The Alliance Pipeline began carrying gas from western Canada to the Midwest on December 1, having been delayed from its original October 2 opening. A new report by Canada's National Energy Board predicts that gas deliverability from Western Canada will rise by 1.1 bcf/d by 2002, due to the ongoing drilling boom. Western Canada supplies 15 percent of the gas consumed in the United States.

Electricity Demand and Supply

Total annual electricity demand growth (retail sales plus industrial generation for own use) is projected at about 2.2 percent in 2001 and 2.3 percent in 2002. This is compared with estimated demand in 2000 that was 3.6 percent higher than the previous year's level. Electricity demand growth is expected to be slower in the forecast years than it was in 2000 partly because economic growth is also slowing from its higher 2000 level.

This winter's overall heating degree-days (HDD) are assumed to be about 17 percent above last winter's HDD, which were well below normal. This is based on the very cold temperatures seen in November and December, the somewhat more moderate rise in HDD in January and February, as well as on the assumption that the less than one month remaining of winter will be normal. This winter, total electricity demand is expected to be up by 4.6 percent over last winter's level, driven by increased demand in the residential and commercial sectors, which are expected to be up by 8 and 4 percent, respectively (Figure 17 and Table 10).

In the fourth quarter of 2000, previously falling demand for oil-fired generation began to turn around as the price differential between natural gas and oil in the electricity generating sector shifted to favor oil, prompting those plants which can switch to oil to do so. This trend is projected to continue through first quarter 2001. Although the favorable price differential for oil relative to gas is expected to continue through the forecast period, by the second half of 2001, expected increases in gas-fired capacity are expected to keep gas demand for power generation growing.

Natural gas supply and deliverability problems in California for gas-fired electricity generation have helped to boost gas price to electric producers and other consumers. The situation in California is characterized by low gas storage, gas pipeline bottlenecks, high demand and low hydropower availability. These supply problems are following on last summer's supply problems with no obvious end visible over the next two years. Average California gas prices dramatically outstripped prices elsewhere in the country through December but have since been coming down as weather-related demand has eased up somewhat (Figure 18).

Table HL1. U. S. Energy Supply and Demand

(Energy Information Administration/Short-Term Energy Outlook – March 2001)

	Year				Annual Percentage Change		
	1999	2000	2001	2002	1999-2000	2000-2001	2001-2002
Real Gross Domestic Product (GDP) (billion chained 1996 dollars)	8876	9321	9526	9928	5.0	2.2	4.2

Imported Crude Oil Price [a] **(nominal dollars per barrel)**	**17.22**	*27.72*	*26.57*	*25.43*	*61.0*	*-4.1*	*-4.3*
Petroleum Supply (million barrels per day)							
Crude Oil Production [b]	**5.88**	*5.84*	*5.84*	*5.84*	*-0.7*	*0.0*	*0.0*
Total Petroleum Net Imports (including SPR)	**9.91**	*10.11*	*10.71*	*11.00*	*2.0*	*5.9*	*2.7*
Energy Demand							
World Petroleum (million barrels per day)	**74.9**	*75.7*	*77.2*	*78.9*	*1.1*	*2.0*	*2.2*
Petroleum (million barrels per day)	**19.52**	*19.49*	*19.76*	*20.21*	*-0.2*	*1.4*	*2.3*
Natural Gas (trillion cubic feet)	**21.70**	*22.65*	*23.18*	*24.14*	*4.4*	*2.3*	*4.1*
Coal [c] **(million short tons)**	**1044**	*1078*	*1085*	*1095*	*3.3*	*0.6*	*0.9*
Electricity (billion kilowatthours)							
Retail Sales [d]	**3312**	*3414*	*3468*	*3543*	*3.1*	*1.6*	*2.2*
Nonutility Use/Sales [e]	**185**	*210*	*236*	*247*	*13.5*	*12.4*	*4.7*
Total	**3497**	*3624*	*3704*	*3790*	*3.6*	*2.2*	*2.3*
Total Energy Demand [f] **(quadrillion Btu)**	**97.1**	*98.4*	*99.2*	*101.3*	*1.3*	*0.8*	*2.1*
Total Energy Demand per Dollar of GDP (thousand Btu per 1996 Dollar)	**10.94**	*10.56*	*10.42*	*10.20*	*-3.5*	*-1.3*	*-2.1*
Renewable Energy as Percent of Total [g]	7.2	*7.0*	*7.0*	*7.0*			

[a]Refers to the refiner acquisition cost (RAC) of imported crude oil.

[b]Includes lease condensate.

[c]Total Demand includes estimated Independent Power Producer (IPP) coal consumption.

[d]Total of retail electricity sales by electric utilities and power marketers. Utility sales for historical periods are reported in EIA's *Electric Power Monthly* and *Electric Power Annual*. Power marketers' sales for historical periods are reported in EIA's Electric Sales and Revenue, Appendix C. Data for 2000 are estimates.

[e]Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 2000 are estimates.

[f]The conversion from physical units to Btu is calculated by using a subset of conversion factors used in the calculations performed for gross energy consumption in Energy Information Administration, *Monthly Energy Review* (*MER*). Consequently, the historical data may not precisely match those published in the *MER* or the *Annual Energy Review (AER)*.

[g]Renewable energy includes minor components of non-marketed renewable energy, which is renewable energy that is neither bought nor sold, either directly or indirectly, as inputs to marketed energy. The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

SPR: Strategic Petroleum Reserve.

Notes: Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Latest data available from Bureau of Economic Analysis and Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual*, DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; and *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-0520; *Weekly Petroleum Status Report*, DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0101.

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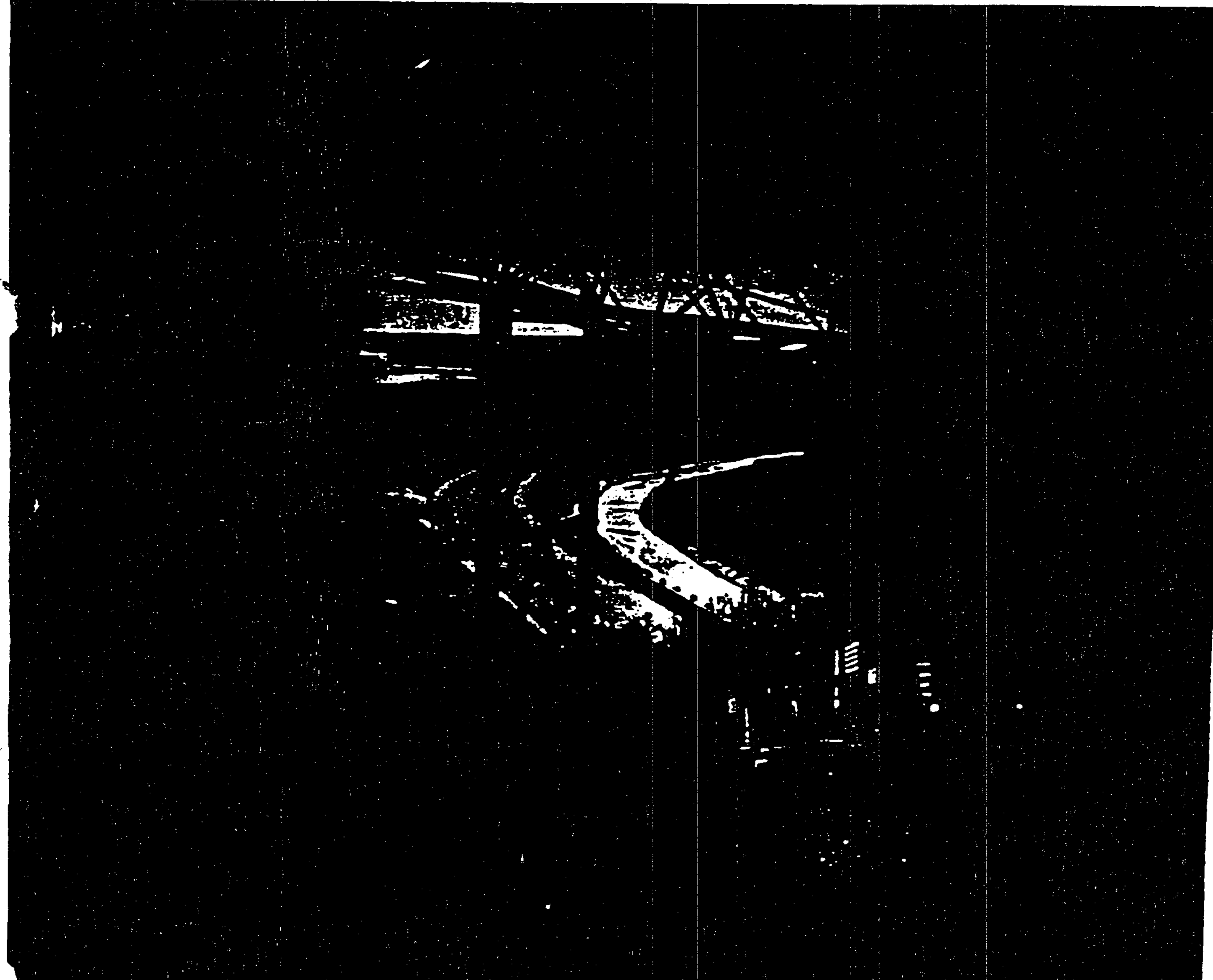
October 2000

Energy Policy Act Transportation Rate Study:
Final Report on Coal Transportation



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We thank Mr. Dan Kojecki of Houston Lighting and Power (HL&P) for the use of the cover background photograph of a unit train of coal at HL&P's W. A. Parish power plant. We also would like to express appreciation to Matt Lawler of Staunton, Va., for the use of his photograph of the Norfolk Southern #8646 at the point of six locomotives on the Shenandoah Valley line bound for the Shenandoah yard.

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Preface

This is the final in a series of reports prepared for the U.S. Congress by the Secretary of Energy on coal distribution and transportation rates as mandated by Title XIII, Section 1340, "Establishment of Data Base and Study of Transportation Rates," of the Energy Policy Act of 1992 (P.L. 102-486).

Section 1340 of the Energy Policy Act of 1992 states:

> (a) **Data Base** - The Secretary [of Energy] shall review the information currently collected by the Federal Government and shall determine whether information on transportation rates for rail and pipeline transport of domestic coal, oil, and gas during the period of January 1, 1988, through December 31, 1997, is reasonably available. If he determines that such information is not reasonably available, the Secretary shall establish a data base containing, to the maximum extent practicable, information on all such rates. The confidentiality of contract rates shall be preserved. To obtain data pertaining to rail contract rates, the Secretary shall acquire such data in aggregate form only from the Interstate Commerce Commission, under terms and conditions that maintain the confidentiality of such rates.
>
> (b) **Study** - The Energy Information Administration shall determine the extent to which any agency of the Federal Government is studying the rates and distribution patterns of domestic coal, oil, and gas to determine the impact of the Clean Air Act as amended by the Act entitled "An Act to amend the Clean Air Act to provide for attainment and maintenance of health protective national ambient air quality standards, and for other purposes," enacted November 15, 1990 (Public Law 101-549), and other Federal policies on such rates and distribution patterns. If the Energy Information Administration finds that no such study is underway, or that reports of the results of such study will not be available to the Congress providing the information specified in this subsection and subsection (a) by the dates established in subsection (c), the Energy Information Administration shall initiate such a study.
>
> (c) **Reports to Congress** - Within one year after the date of enactment of this Act, the Secretary shall report to the Congress on the determination the Energy Information Administration is required to make under subsection (b). Within three years after the date of enactment of this Act, the Secretary shall submit reports on any data base or study developed under this section. Any such reports shall be updated and resubmitted to the Congress within eight years after such date of enactment. If the Energy Information Administration has determined pursuant to subsection (b) that another study or studies will provide all or part of the information called for in this section, the Secretary shall transmit the results of that study by the dates established in this subsection, together with his comments.
>
> (d) **Consultation with Other Agencies** - The Secretary and the Energy Information Administration shall consult with the Chairmen of the Federal Energy Regulatory Commission and the Interstate Commerce Commission in implementing this section.

The data for this report were collected and processed through the considerable effort and cooperation of a number of people: Doug Matyas and Patricia Morris of the Federal Energy Regulatory Commission (FERC); Jim Nash and Bill Washburn of the Surface Transportation Board; Dan Walzer of SAIC, who pored over thousands of pages of FERC Form 580 reports over the years; Abbas Malekghassemi, who developed programs and systems to process and analyze the Coal Transportation Rate Database; Dan Hurley of Washington Consulting Group, who contributed tirelessly in data validation and analysis; Terry Varley, Terri Thigpen, and Sarah Loats of Walcoff Technologies who put text and statistics into clear formats and a readable report, and Kenny McClevey of EIA, who lent his expertise with FERC Form 423 to resolve differences with FERC Form 580 data.

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Executive Summary

This is the third and final report to Congress by the Secretary of Energy, required by Title XIII of the Energy Policy Act of 1992. It examines changes in domestic coal transportation rates and coal distribution patterns since the enactment of the Clean Air Act Amendments of 1990 (CAAA90).

The Congress anticipated that the sulfur dioxide (SO_2) emission limitations imposed by Title IV of CAAA90, Acid Deposition Control, would induce many operators of coal-fired power plants to shift to low-sulfur coal for generating electricity. Moreover, it was further anticipated that this shift would in turn lead to significant changes in regional patterns of coal production and distribution and to increases in shipping distances for coal.

Concerned about the potential for escalation in the rates charged by railroads to transport coal, Congress directed the Energy Information Administration (EIA) to compile a database on transportation rates for domestic coal covering the period January 1, 1988 through December 31, 1997, and to prepare this report.

Impacts of the Clear Air Act Amendments of 1990 on Coal Demand

The provisions of CAAA90 aimed at reducing acid rain imposed new standards limiting the emission of SO_2 from fossil-fueled electric generating plants in two phases. This report focuses on the impacts of Phase I, which extended from January 1, 1995 through December 31, 1999 and applied to existing power plants specifically identified in the legislation and to generating units used to substitute or compensate for those plants. Almost all of the affected plants are located in the eastern half of the United States.

A range of compliance options were available to the owners of the affected power plants through an innovative program of market trading of emission allowances. These options included switching to lower-sulfur coal, investing in flue gas desulfurization equipment to allow the continued use of high-sulfur coal, or purchasing additional emission allowances.

A study of power plant compliance plans prepared by the EIA in 1997 found that approximately one half of the affected plants chose to comply with the Phase I requirements by switching to a lower-sulfur coal or by blending a lower-sulfur coal with the coal they were currently using. Now, this current analysis also finds that:

- Nationally, the average sulfur content of the coal delivered to electric utilities during the study period declined by 13 percent, from 1.26 pounds of sulfur per million British thermal units (Btu) in 1988 to 1.09 pounds of sulfur per million Btu in 1997.
- The largest reductions in average sulfur content of coal receipts occurred in the four Census Divisions where the coal-fired power plants affected by Phase I began using more lower-sulfur coal: 47 percent in the West North Central Division, 22 percent in the East North Central Division, 13 percent in the South Atlantic Division, and 9 percent in the East South Central Division.
- The average sulfur content of the coal delivered to electric utilities in the remaining Census Divisions did not decline, either because the power plants in those regions were unaffected by Phase I, or because plant owners chose to comply with Phase I by installing flue gas desulfurization systems or by purchasing additional sulfur emission allowances.

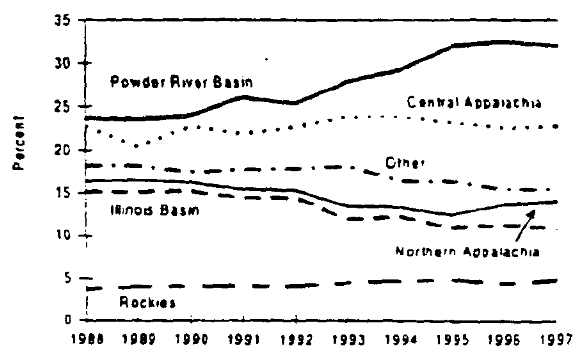
Apart from changes in the sulfur characteristics of the coal delivered to electric utilities, the amount of coal delivered to them increased by 20 percent between 1988 and 1997. Demand for coal by the electric utilities increased with the growth in electricity sales, averaging 2.2 percent per year. To meet this higher demand for electricity, the utilization rates for existing coal-fired plants rose from 60 percent in 1988 to 67 percent in 1997. By 1997, the coal shipped to electric utilities accounted for 88 percent of total domestic coal shipments.

Coal Distribution Patterns

Largely as a result of this growth in demand for coal by electric utilities, total shipments of domestic coal to all consumers rose from 854 million short tons in 1988 to 995 million short tons in 1997. This growth in total shipments was accompanied by a significant shift in the origin of the domestic coal distributed.

The share of coal from the characteristically higher-sulfur coal regions of Northern Appalachia and the Illinois Basin declined, while shipments of low-sulfur subbituminous coal from the Powder River Basin increased (Figure ES1). The combined effects of larger quantities of Powder River Basin coal moving a greater distance to markets in the East led to a 24 percent increase in the average distance of all contract coal shipments, from 640 miles in 1988 to 793 miles in 1997.

Figure ES1. Supply Region Shares of Domestic Coal Distribution



Source: Energy Information Administration, EIA-6, "Coal Distribution Report."

The share of coal shipments from the Powder River Basin to regions east of the Mississippi River increased from 19 percent to 35 percent in the East North Central Division, from 0 to 4 percent in the South Atlantic Division, and from 0 to 10 percent in the East South Central Division. Powder River Basin coal also displaced North Dakota lignite in the West North Central Division.

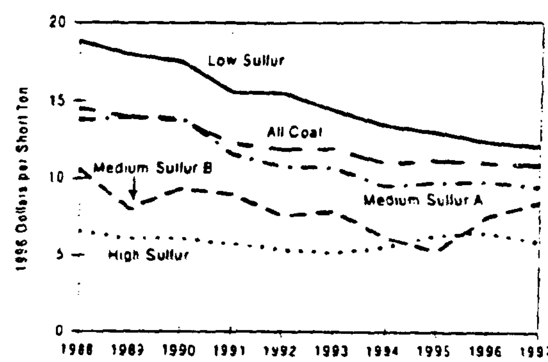
Powder River Basin coal captured more of the domestic market because of a 57 percent drop in the average minemouth price and a 35 percent decline in the transportation rate (measured in dollars per ton) for contract coal shipments from that region to investor-owned utilities. The two other supply regions producing low sulfur coal, Central Appalachia and the Rockies, also experienced declining minemouth prices and transportation rates. However, the share of coal from the Rockies increased only minimally to 5 percent of the total and the share of coal receipts from Central Appalachia, the Nation's primary source of bituminous low sulfur coal, remained fairly stable at 23 percent. By 1997, the average delivered price for coal from the Powder River Basin was $1.49 per million Btu versus $1.88 for Central Appalachian coal and $1.65 for coal from the Rockies.

Coal Transportation Trends

Since over 85 percent of the coal distributed from the Powder River Basin is transported by rail, the overall rail share of total domestic coal shipments increased from 57.5 percent in 1988 to 61.8 percent in 1997 as the Powder River Basin accounted for an increasing share of total coal distributed. Shipments of coal by river barge and by truck generally retained their shares, while the aggregate of shipments by other modes (including shipments via the Great Lakes, tidewater ports, conveyor, tramway, and slurry pipelines) lost market share to rail.

Although the share of coal transported by the railroads increased, the average rate per ton to ship contract coal by rail fell steadily (a 25.8 percent decline) during the study period. The rates for coal in all sulfur categories were lower in 1997 than in 1988 (Figure ES2). Notably, the greatest decline in dollar-per-ton coal rail rates

Figure ES2. Average Rate per Ton for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997



Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu.

Source: Energy Information Administration, Coal Transportation Rate Database.

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(35 percent) was for low-sulfur coal. The general finding of declining rates was also substantiated when the rates were calculated as a rate per ton mile, a rate per million Btu, or rates between specific supply and demand regions.

Once the electric utilities determined that they could switch and burn the subbituminous Powder River Basin coal in their existing plant boilers without major capital expenditures, competition between the eastern and western producers contributed to efficiency improvements and declining transportation rates. Accordingly, this study found no evidence of widespread inflation of shipping rates by the major coal-hauling railroads following enactment of the Clean Air Act Amendments of 1990.

The Coal Transportation Rate Data Base (CTRDB) used to prepare this report is available on the EIA website at: www.eia.doe.gov/cneaf/coal/page/database.html. Detailed information on individual coal supply contracts in effect in 1997 can also be found in Appendix B.

1. Introduction

This is the third and final report on coal distribution patterns and transportation rates presented to the Congress by the Secretary of Energy, as required by Title XIII of the Energy Policy Act of 1992. Congress recognized that new air emission standards, legislated in the Clean Air Act Amendments of 1990 (CAAA90) (P.L. 101-549), would likely have a substantial and far-reaching effect on power plant fuel choices, and on the producers and transporters of fuels. Accordingly, the Energy Information Administration was directed to prepare this series of reports on the availability of coal transportation rate information covering the time period January 1, 1988, through December 31, 1997, and the impact of the CAAA90 on rail coal transportation rates and distribution patterns.

Prior to the CAAA90, changes in rail rates had already begun. The Railroad Revitalization and Regulatory Reform Act of 1976 and, especially, the Staggers Rail Act of 1980 had substantially deregulated U.S. railroads and had given them wide latitude to set their own rates. The Staggers Act also legalized confidential rail contracts and facilitated railroad mergers. In 1981 rail rates started to reverse the upward trend, declining by 24 percent between that year and 1987.[1] The primary purpose of this present report is to show whether lower contract transportation rates for coal continued after CAAA90.

The CAAA90 was the latest in a succession of legislative efforts to improve and maintain air quality in the United States. Title IV of the Act, Acid Deposition Control, set rigid standards limiting the emission of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from existing and new fossil-fueled electric power generating plants and, to a lesser extent, from other industrial and transportation sources. NO_x, which results from oxidation of nitrogen in the air itself during combustion of fossil fuels, is controlled by improvements in combustion techniques and is not a subject of this report. SO_2 comes from sulfur and sulfur compounds contained in the fossil fuels. The new SO_2 standards are administered by the Environmental Protection Agency (EPA) and were implemented in two phases. Phase I, which applied to existing power plants emitting the largest amounts of SO_2, was in effect from 1995 until 2000. The plants affected by Phase I were either listed in the CAAA90 or were chosen by the plant owners to substitute or compensate for plants listed. Almost all are located in the eastern half of the United States. Phase II, which commenced on January 1, 2000, tightened the standards for Phase I plants and applied to virtually all other power plants with a capacity greater than 25 megawatts. Phase II did include the grandfathered plants that were exempt from the new and revised new source performance standards of earlier versions of the Clean Air Act Amendments.

The Act provides power plant owners and operators with a range of SO_2 compliance options through an innovative program of marketable emission allowances. Each allowance represents an entitlement to emit 1 ton of SO_2. The power plant owners are allocated yearly allowances by the EPA based on a formula that takes into account the historical fuel consumption by the plant from 1985 through 1987. The number of available allowances is capped at a level calculated to achieve the overall goals of the Act, with provisions that allowances may be sold or exchanged on the open market. The mandated reductions in emissions to the level of allowances held by the plant owner or operator may be achieved by switching to a lower sulfur fuel, by outfitting some generating units with pollution control devices, by altering the equipment at some generating units, e.g., converting the boiler to an integrated gasification combined-cycle unit, or by retiring some generating units.

Over half of the coal-fired generating units affected by Phase I, came into compliance by switching to a lower-sulfur coal or blending a lower-sulfur coal with the coal they had been using. This resulted in significant changes in coal sources with increased shipments coming from regions with low-sulfur coal resources. Given the location of low-sulfur coal reserves in relation to the demand regions affected by Phase I of the CAAA90, another implication was that the coal would have to be shipped increased distances from the mine to the utility plant.

[1] Energy Information Administration, *Trends in Contract Coal Transportation, 1979-1987*, DOE/EIA-0549 (Washington, DC, September 1991), p. 16-18

With data through 1997, only the effects of Phase I of the CAAA90 are captured in this report. However, some utilities planned ahead for Phase II and over-complied with the annual emission reduction requirements of Phase I to create a surplus of emission allowances. Since the allowances have no fixed expiration date, they can be saved and either used in a later year or sold in the allowance market. The banking of allowances will delay the full impact of Phase II on coal markets until after 2000.

This report provides an analysis of the domestic coal distribution patterns and railroad coal transportation rates over the period 1988 through 1997. It is based on data from two surveys—the EIA-6, "Coal Distribution Report" and the Federal Energy Regulatory Commission (FERC) Form-423, "Monthly Report on the Cost and Quality of Fuels for Electric Utility Plants"—as well as the Coal Transportation Rate Database (CTRDB) maintained by the Energy Information Administration. The data contained in the CTRDB are primarily from a survey of investor-owned electric utilities conducted by the FERC called Form 580, "Interrogatory on Fuel and Energy Purchase Practices." This database has been expanded from the Interim coal transportation rate study, which was sent to Congress in October 1995.[2] Not only were the years of coverage updated from 1993 through 1997, but additional data from the Surface Transportation Board's "Annual Way Bill Sample" and from the FERC Form-423 were analyzed and added to the database to broaden the scope and include some information about coal shipments to publicly owned utilities. A detailed description of the database can be found in Appendix A.

The database and this report focus on contract coal shipments by railroads to electric utilities. Through 1997, ownership of electric generating units was dominated by utilities. It should be noted, however, that since 1997 the electric power industry has changed due to electricity competition and restructuring.[3] Retail electricity competition, which began in 1998 in California, and subsequently in a few additional States, is resulting in utilities divesting their generating assets to nonutility companies. In addition, more than half of new plants being built are owned by nonutility companies. In the future, data on coal receipts and transportation rates for utility and nonutility power plants would be required for an accurate assessment of industry trends.

[2] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995).

[3] Energy Information Administration, *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*, DOE/EIA-0562(99) (Washington, DC, December 1999).

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2. Coal Distribution and Sulfur Content

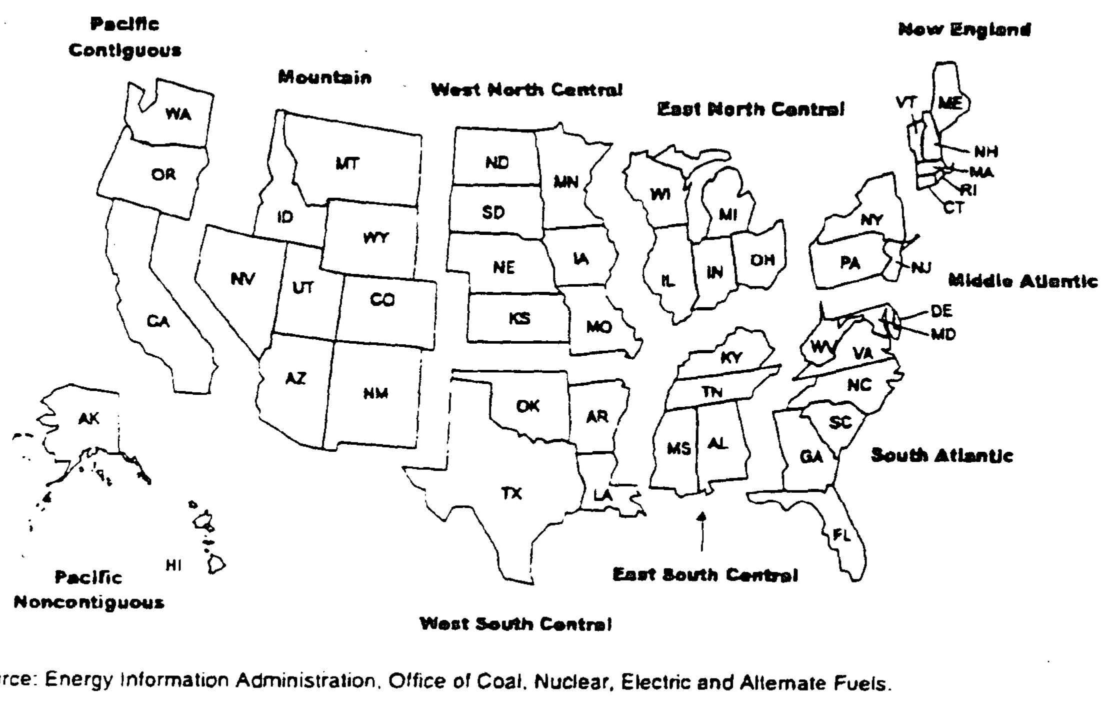
In 1997, total shipments of domestic coal to coke plants, manufacturers, electricity generators, and residential/commercial consumers increased to 995 million short tons from 854 million short tons in 1988. This increase was driven by the demand for coal by the electric generators (utilities and independent power producers[4]). By 1997, electric utility generators were receiving 88 percent of the total domestic coal shipments.

Coal Demand by Region

The coal receipts by electric utility generators and all consumers vary widely across the U.S. Census Divisions (Figure 1). The share of coal received in each region, as a percent of the U.S. total, is directly related to the share of electric utility owned coal-fired generating capacity in the region (Table 1). For example, seven of the nine Census Divisions contain 98 percent of the coal-fired generating capacity and received almost 99 percent of the coal shipped to electric utility generators in 1997. New England and the Pacific Division are the two regions with less than 1 percent of the coal-fired capacity and coal receipts. The focus of this chapter is on the seven regions that account for most of the coal receipts.

The growth in coal receipts by electric utility generators in 1988, 1993, and 1997 is primarily due to the increased utilization of the existing electric utility owned coal-fired generating units rather than construction of new

Figure 1. Coal Demand Regions (Census Divisions)



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

[4] Independent power producers are defined in this report as nonutility wholesale producers of electricity that are not included in the industrial or commercial sectors. They have an industrial classification code of NAICS 22 and account for approximately 2 percent of the coal consumed by electric generators in 1997.

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Table 1. Coal Demand Regions and Relevant Characteristics, 1988, 1993, and 1997

Demand Region	Total Domestic Coal Receipts						Domestic Coal Received by Electric Utility Generators						Electric Utility Coal-Fired Generating Net Summer Capability					
	Thousand Short Tons			Percent of U.S. Total			Thousand Short Tons			Percent of U.S. Total			Capability (Gigawatts)			Percent of U.S. Total		
	1988	1993	1997	1988	1993	1997	1988	1993	1997	1988	1993	1997	1988	1993	1997	1988	1993	1997
New England	6,696	4,141	6,414	0.8	0.5	0.6	6,325	4,555	5,324	0.9	0.6	0.6	2.7	2.6	2.7	0.9	0.9	0.9
Middle Atlantic	70,253	64,421	76,487	8.2	7.3	7.7	51,532	46,511	53,687	7.1	6.1	6.1	23.0	23.0	22.9	7.8	7.6	7.6
East North Central	193,389	196,343	237,757	22.6	22.2	23.9	155,300	165,684	202,401	21.4	21.7	23.1	74.5	77.0	75.4	25.3	25.6	24.9
West North Central	112,365	116,337	131,862	13.2	13.2	13.3	99,540	101,896	120,150	13.7	13.3	13.7	34.5	34.9	35.3	11.7	11.6	11.7
South Atlantic	141,606	141,701	166,234	16.6	16.0	16.7	120,058	118,366	146,847	16.5	15.5	16.8	62.9	64.6	67.4	21.4	21.5	22.2
East South Central	85,737	97,057	108,478	10.0	11.0	10.9	73,868	86,610	102,352	10.2	11.3	11.7	35.9	36.6	36.2	12.2	12.2	11.9
West South Central	126,542	139,664	143,816	14.8	15.8	14.5	117,144	130,848	135,759	16.1	17.1	15.5	30.4	31.4	31.8	10.3	10.4	10.5
Mountain	104,271	109,200	113,046	12.2	12.4	11.4	97,184	103,137	103,539	13.4	13.5	11.8	28.4	28.8	29.3	9.7	9.6	9.7
Pacific	8,661	10,791	9,596	1.0	1.2	1.0	5,856	6,917	5,657	0.8	0.9	0.6	1.8	2.0	2.0	0.6	0.7	0.7
U.S. Total	**853,930**	**883,934**	**995,181**	**100.0**	**100.0**	**100.0**	**726,806**	**764,524**	**875,717**	**100.0**	**100.0**	**100.0**	**294.2**	**300.9**	**302.9**	**100.0**	**100.0**	**100.0**

Notes: U.S. total coal receipts include those for which destination is unknown. • U.S. total coal-fired generating capacity in Pacific Region includes non-contiguous States. • Totals may not equal sum of components because of independent rounding. • Domestic coal accounted for 92.3 percent of total distribution in 1997.

Sources: Total Domestic Coal Receipts - 1988: *Coal Distribution Report 1988*, Table 8. • Total Domestic Coal Receipts - 1993: *Coal Industry Annual 1993*, pp. 101-102. • Total Domestic Coal Receipts - 1997: *Coal Industry Annual 1997*, Table 61, pp. 104-105. • Coal Received By Electric Generators - 1988: *Coal Distribution Report 1988*, Table 8. • Coal Received By Electric Generators - 1993: *Coal Distribution Report 1993*, (Internal), Table 8. • Coal Received By Electric Generators - 1997: *Coal Distribution Report 1997*, (Internal), Table 8. •Capacity 1997 - *Inventory of Power Plants in the United States, as of January 1, 1998*, Table 16.

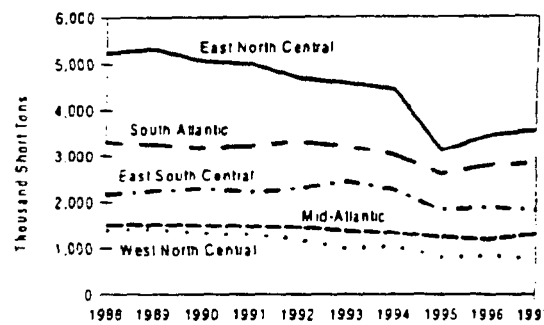
coal-fired power plants. The national average utilization rate for electric utility coal-fired power plants increased from 59.8 percent in 1988, to 62.2 percent in 1993, and 67.4 percent in 1997.[5] This increased utilization is in response to growth in the demand for electricity, as well as changes in electricity generation from other sources. The South Atlantic Division, however, did have four new electric utility owned coal-fired units come online in 1996.

Electric utilities experienced an average annual growth in retail sales of 2.2 percent between 1988 and 1997.[6] Coal-fired generation increased with this demand for electricity and maintained a national average share of total electric utility generation of 57 percent over this time period. The coal share of total electricity generation, including nonutility generation, was also constant at approximately 53 percent.[7] However, regional differences in the share of electricity produced by coal did occur between 1993 and 1997 due to changes in use of petroleum, nuclear power, and hydroelectric generation. Nuclear-powered generation declined significantly in 1997 from the previous year, because several nuclear units were shut down for all or part of 1997. In the East North Central Division, the nuclear generation was even lower in 1997 than it was in 1993, 36 billion kilowatthours less.[8] As a result, the coal share of total electric utility generation increased from 73 to 80 percent in that region and coal receipts by electric generators increased commensurately. In the East South Central Division, the opposite occurred. Nuclear generation increased by 36 billion kilowatthours between 1993 and 1997. Coal receipts by electric generators continued to increase, however, due to increases in demand for electricity, even as the coal share of total electric utility generation declined from 79 percent to 70 percent. In the Middle Atlantic Division, decreased oil-fired generation created more demand for coal in 1997.

This increased utilization of existing coal-fired power plants occurred at the same time that utilities were required to comply with Phase I of the CAAA90. The emission allowances allocated to each plant for Phase I are based on an emission rate of 2.5 pounds of SO_2 per million British thermal units[9] consumed and the historical average fuel consumption by the plant in 1985 through 1987. During 1985, utilization rates were much lower, approximately 56 percent[10] as compared to 67 percent in 1997. Since more coal was being consumed by the coal-fired power plants in 1997 than in 1985 through 1987, additional actions had to be taken to reduce emissions to the allowance levels. Most of the coal-fired power plants affected by Phase I are located in the following five regions Middle Atlantic, East North Central, West North Central, South Atlantic, and East South Central. A few additional coal-fired units, that were substituted for the original units named in the legislation, are located in Massachusetts and Wyoming.[11]

In the five key Census Divisions mentioned above, the SO_2 emissions from all coal-fired plants, not just those affected by Phase I, were lower in 1995 than they were in 1988 (Figure 2). Reductions in emissions were observed even before Phase I began in 1995, as some utilities started testing lower sulfur coals in their power plants.

Figure 2. SO_2 Emissions from Electric Utility Coal-Fired Steam Units, 1988-1997



Source: Energy Information Administration.

[5] Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Tables 8.3 and 8.6.
[6] *Ibid.*, Table 8.9.
[7] *Ibid.*, Tables 8.2 and 8.3.
[8] Energy Information Administration, *Electric Power Annual 1993*, DOE/EIA-0348(93) (Washington, DC, December 1994), Table 13. Energy Information Administration, *Electric Power Annual 1997 Volume I*, DOE/EIA-0348(97/1) (Washington, DC, July 1998), Table 10.
[9] British thermal unit is a measure of the heat content of a quantity of coal or other fuel. It is the quantity of heat needed to raise the temperature of 1 pound of water by 1 F at or near 39.2 F Also, 2.5 pounds of SO_2 emissions are equivalent to 1.25 pounds of sulfur in the coal (assuming complete combustion).
[10] Energy Information Administration, *Inventory of Power Plants in the United States 1985*, DOE/EIA-0095(85) (Washington, DC, August 1986), Table 1. Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Table 8.3.
[11] Energy Information Administration, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, DOE/EIA-0582(97) (Washington, DC, March 1997), Table B1

After 1995 the emissions from coal-fired power plants in the East North Central and the South Atlantic Divisions began to rise, however, as coal-fired generation increased to satisfy greater demand for electricity and to replace the reduced generation from nuclear plants. Although the SO_2 emissions were higher, all utilities had the necessary emission allowances and were in compliance with the Phase 1 requirements.

The reduction in SO_2 emissions has occurred, in part, through a change in the type of coal contracted for and received by electric utilities. Nationwide, the sulfur content of the coal receipts, expressed as pounds of sulfur per million Btu, declined by 13 percent between 1988 and 1997 (Table 2). Most of that decline occurred by 1993 as utilities were beginning to test new or blended coals in their plant boilers. The decline was

Table 2. Average BTU and Sulfur Content of Domestic Coal Received by Electric Utilities, 1988, 1993, and 1997

Demand Region	Receipts (Thousand Short Tons)	Average BTU Per Pound	Avg Sulfur Content (Pounds Per MM BTU)
Middle Atlantic			
1988	51,532	12,403	1.63
1993	46,511	12,556	R1.56
1997	53,687	12,430	1.66
East North Central			
1988	155,300	11,127	R1.64
1993	R165,684	R10,886	R1.48
1997	202,401	10,588	1.28
West North Central			
1988	99,540	8,710	1.16
1993	101,896	8,366	R0.75
1997	120,150	8,394	0.61
South Atlantic			
1988	R120,058	R12,480	1.21
1993	R118,366	R12,482	R1.13
1997	146,847	12,329	1.05
East South Central			
1988	73,868	11,912	R1.73
1993	R86,610	11,988	R1.60
1997	102,352	11,584	1.58
West South Central			
1988	117,144	7,717	0.78
1993	R130,848	R7,642	R0.84
1997	135,759	7,763	0.82
Mountain			
1988	97,184	9,737	0.56
1993	103,137	9,751	R0.55
1997	103,539	9,723	0.58
United States			
1988	R726,806	R10,449	R1.26
1993	R764,524	R10,305	R1.15
1997	875,717	10,266	1.09

R = Data revised since 1995 Interim Report. Revisions exclude receipts of imported coal and use an updated weighted averaging calculation.

Notes: • United States total includes the New England, Pacific Contiguous, and Pacific Noncontiguous Demand regions and coal for which the destination is unknown. • Domestic coal accounted for 92.3 percent of total distribution in 1997.

Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1997*, DOE/EIA-0191(97) (Washington, DC, May 1998) and *Cost and Quality of Fuels for Electric Utility Plants 1993*, DOE/EIA-0191(93) (Washington, DC, July 1994), Tables 1, 15, and 22; *Cost and Quality of Fuels for Electric Utility Plants 1988*, DOE/EIA-0191(88) (Washington, DC, August 1989), Table 48.

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greatest in the East North Central and West North Central Divisions, where the average sulfur content fell by 22 and 47 percent, respectively, from 1988 to 1997. The sulfur content of coal received by electric utilities in the South Atlantic and East South Central Divisions also went down over those years. The sulfur content of coal receipts in the West South Central and Mountain regions did not decline, but it was already lower than the national average. In general, those regions were not affected by the Phase I requirements, except through a few substitution units located in Wyoming. Coal-fired power plants in the Middle Atlantic region met the requirements of Phase I by installing flue gas desulfurization equipment on some of the coal-fired power plants and by obtaining additional allowances for most of the others. Although a few plants did shift to a lower sulfur coal, the average sulfur content of all coal receipts in the region did not decline from the 1988 levels.

The national average Btu per pound of coal received, i.e. the heat content of the coal, declined slightly over these years, less than 2 percent. However, this decline in the heat content of coal receipts accounts for approximately 10 percent of the increase in the tonnage of reported coal receipts. The largest decreases in heat content, of 4.8, 3.6, and 2.8 percent, occurred in three regions, East North Central, West North Central, and East South Central, respectively, between 1988 and 1997. Since coal characteristics vary across the supply regions, these changes indicate that the sources of coal supplied to the electric generators have changed. The supply and distribution patterns are described in the following sections.

Coal Supply By Region

Regions Defined

The Nation's coal supply regions are illustrated in Figure 3 and their respective contributions to 1997 total supply are contained in Table 3. Compared with coal demand regions, which are based upon State boundaries and Census Divisions, definitions of the Nation's coal supply regions are somewhat more complex. They evolved from producing district boundaries defined in the Bituminous Coal Act of 1937 and, especially in the East, were based upon the location of mining districts and their associated river and rail transportation infrastructure.

Regional Coal Characteristics

Despite its apparent simplicity, coal is a complex substance with myriad chemical characteristics that determine its suitability for use as a fuel and as a key ingredient in the manufacture of steel and other products. Among the most important distinguishing characteristics of coal are heat content, sulfur content, and ash content.

While a detailed examination of the Nation's coal characteristics by supply region is beyond the scope of this report, general observations about the characteristics of the Nation's coal supplies provide a useful framework for this analysis.

The Powder River Basin of Wyoming is the Nation's leading source of low-sulfur, low-Btu subbituminous coal. Coal from this region typically has a heating value in the range of 8,500 to 8,900 Btu per pound with a sulfur content of 0.3 to 0.5 pounds of sulfur per million Btu.

The Central Appalachian region, comprising roughly Virginia, the eastern portion of Kentucky, and the southern portion of West Virginia, is the Nation's primary source of bituminous coal that is relatively low in sulfur. Heat content is significantly higher than Wyoming coal. Heating values for Central Appalachian coal average approximately 12,500 Btu per pound, with a sulfur content averaging 0.85 pounds of sulfur per million Btu.

Similarly, coal from the Southern Appalachian Region, which includes Alabama and Tennessee, features an average heat content of about 12,500 Btu per pound, but a moderately higher sulfur content in the range of 0.8 to 1.2 pounds of sulfur per million Btu.

By comparison, coal from Northern Appalachia (Maryland, Ohio, northern West Virginia, and the bituminous coal regions of Pennsylvania) and from the Illinois Basin (western Kentucky, Illinois and Indiana) has a relatively high sulfur content, ranging from 1.4 to 3.5 pounds sulfur per million Btu, with heating values in the range of 11,000 to 13,000 Btu per pound.

Coals being produced from the Rockies (including primarily Colorado and Utah) and from the Southwest region are similar in sulfur content to Wyoming coal but have a substantially higher range of heating values. Southwest region subbituminous and bituminous coals

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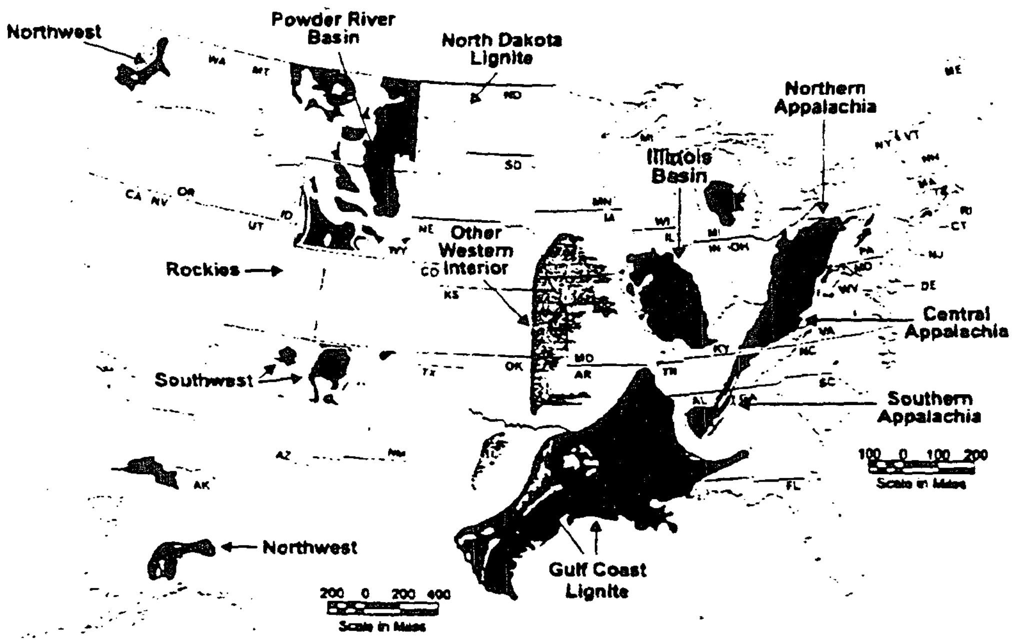
Figure 3. Coal Supply Regions



Region	States
Northern Appalachia	MD, OH, PA, Northern WV
Central Appalachia	Eastern KY, VA, Southern WV
Southern Appalachia	AL, TN
Illinois Basin	Western KY, IL, IN
Gulf Coast Lignite	TX, LA, MS
Other Western Interior	AR, IA, KS, MO, OK
Powder River Basin	WY, MT
North Dakota Lignite	ND
Southwest	AZ, NM
Rockies	CO, UT
Northwest	AK, WA

Notes: Labels indicate active areas in major coal supply regions. Peripheral areas are areas of little or no current coal production. States cited in each region are States currently producing coal. If inactive coalfields in other States begin producing, those States would be listed at that time.

Source: Energy Information Administration. Adapted from EIA's Map of Coal-Bearing Areas.

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Table 3. Coal Supply Regions and Their Domestic Coal Distribution Shares, 1997

Region	Coal Distribution (Thousand Short Tons)	Percent of U.S. Total
Northern Appalachia	139,425	14.0
Central Appalachia	227,346	22.8
Southern Appalachia	20,875	2.1
Illinois Basin	108,282	10.9
Texas & Louisiana Lignite	57,008	5.7
Other Western Interior	2,532	0.2
Powder River Basin	318,618	32.0
North Dakota Lignite	29,172	2.9
Southwest	38,396	3.9
Rockies	48,302	4.9
Northwest	5,224	0.5
U.S. Total	**995,181**	**100.0**

Notes: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 61.

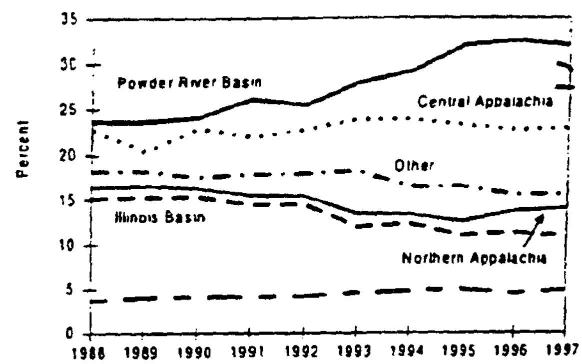
range from 9,000 to 12,000 Btu per pound. Colorado and Utah bituminous coals are typically in excess of 11,000 Btu per pound. The coal-producing regions of Texas, Louisiana, and North Dakota are characterized by lignite, a brownish-black coal of low rank with a high moisture content. Heating values for currently mined lignites average about 6,500 Btu per pound.[12]

Coal Distribution Shares By Supply Region

Unlike shares of total coal demand by region, the domestic coal distribution shares attributable to the various coal supply regions changed significantly between 1988 and 1997. As shown in Figure 4, the supply regions most affected by these changes have been Northern Appalachia, the Illinois Basin, and Powder River Basin.

Nationwide, the share of coal from Northern Appalachia declined from 16.5 in 1988 to 13.5 percent in 1993, before rising to 14.0 percent in 1997. Similarly, the share attributable to coal fields in the Illinois Basin declined from 15.2 percent in 1988 to 10.9 percent in 1997. Concurrently, the share of distributed coal originating in

Figure 4. Supply Region Shares of Domestic Coal Distribution



Source: Energy Information Administration, Coal Transportation Rate Database.

the Powder River Basin increased from 24.3 percent in 1988 to 32.0 percent in 1997.

Overall, the following trends emerge from the information presented in Table 4.

- Nationwide, the origin of domestic coal receipts by all consumers (electric utilities, independent power producers, industrial and residential/commercial users) clearly shifted from the characteristically higher sulfur Northern Appalachian and Illinois Basin regions to the lower sulfur Powder River Basin and the Rockies regions as coal consumers implemented CAAA90 compliance strategies based upon fuel switching and blending. This trend occurred in four of the five demand regions that had power plants affected by Phase I of the CAAA90.

- In the East North Central demand region, which accounted in 1997 for nearly one-quarter of U.S. coal receipts, coal consumers shifted from Central Appalachian and Illinois Basin coal, and to a lesser extent from Northern Appalachian coal, to coal supplied from the Powder River Basin and the Rockies. The share of coal receipts supplied by Northern Appalachia declined from 20.4 percent in 1988 to 17.2 percent in 1997, while the shares supplied by Central Appalachia and the Illinois Basin declined from 28.9 percent to 22.9 percent and from 31.9 percent to 23.6 percent, respectively.

[12] Sulfur and Btu values based on coal delivered to electric utilities. Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1998 Tables*, DOE/EIA-0191 (Washington, DC, June 1999), Table 23.

Table 4. Percentage of Demand Region Coal Receipts Coming from Each Supply Region, 1988, 1993, and 1997

Demand Region	Supply Region						
	Northern Appalachia	Central Appalachia	Illinois Basin	Powder River Basin	Rockies	Other[a]	Total Coal Received[b] (Thousand Short Tons)
Middle Atlantic							
1988	87.7	12.3	0.0	0.0	0.0	0.0	70,253
1993	79.5	19.7	0.0	0.0	0.0	0.8	64,421
1997	80.0	19.5	0.0	0.0	0.0	0.5	76,487
East North Central							
1988	20.4	28.9	31.9	18.7	0.1	0.0	193,389
1993	18.3	26.3	26.0	27.2	1.5	0.7	196,343
1997	17.2	22.9	23.6	34.6	1.4	0.3	237,757
West North Central							
1988	0.1	1.2	16.9	50.0	0.2	31.6	112,365
1993	0.3	0.6	8.1	61.1	1.1	28.8	116,337
1997	0.2	0.6	3.5	70.5	2.3	22.9	131,862
South Atlantic							
1988	22.9	65.7	11.0	0.0	0.0	0.4	141,606
1993	18.4	72.4	8.1	0.7	0.1	0.3	141,701
1997	17.9	71.7	6.3	4.0	0.0	0.1	166,234
East South Central							
1988	3.7	34.2	38.3	0.0	0.0	23.8	85,737
1993	1.9	40.3	34.9	0.5	0.7	21.7	97,057
1997	3.5	30.1	33.1	10.2	4.5	18.6	108,478
West South Central							
1988	0.1	0.2	0.1	52.3	1.8	45.5	126,542
1993	0.1	0.1	0.1	54.9	1.9	42.9	139,664
1997	0.2	0.1	0.8	56.1	1.6	41.2	143,816
Mountain							
1988	0.0	0.3	0.0	41.1	26.9	31.7	104,271
1993	0.2	0.2	0.0	37.9	26.5	35.2	109,200
1997	0.2	0.5	0.0	38.4	27.9	33.0	113,046
United States							
1988	**16.5**	**22.8**	**15.2**	**24.3**	**3.9**	**17.3**	**853,930**
1993	**13.5**	**23.9**	**12.0**	**27.9**	**4.5**	**18.2**	**883,934**
1997	**14.0**	**22.8**	**10.9**	**32.0**	**4.9**	**15.3**	**995,181**

[a]The principal "other" coal supply sources are: North Dakota, for the West North Central Region; Alabama, for the East South Central Region; Texas, for the West South Central Region; and Arizona and New Mexico, for the Mountain Region.

[b]Total coal includes domestic coal receipts only. Imported coal accounted for 7.7 percent of total distribution in 1997.

Notes: • United States total includes the New England and Pacific Coal Demand regions and coal for which the destination is unknown. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1994), Table 61; and *Coal Distribution* January-December 1988, DOE/EIA-0125(88/4Q) (Washington, DC, March 1989), pp. 43-49.

Concurrently, the combined portion of coal supplied by the Powder River Basin and the Rockies soared from 18.8 percent in 1988 to 36 percent in 1997.

- In the West North Central demand region, the combined share of coal demand satisfied by coal from the Illinois Basin and from indigenous sources (mostly North Dakota lignite) declined sharply (from 42.6 percent in 1988 to 26.4 percent in 1997) as the region's coal consumers turned increasingly to the Powder River Basin and the Rockies to satisfy increased coal demand and comply with the CAAA90.

- In the East South Central region, shares of coal from Central Appalachia, the Illinois Basin, and other indigenous sources (mostly Southern Appalachia) declined in favor of sharply increased shares from the Powder River Basin and the Rockies (0 percent in 1988 to 14.7 percent in 1997).

- In the South Atlantic demand region, the shares of coal coming from Northern Appalachia and the Illinois Basin declined while the share from the Central Appalachia increased from 65.7 percent in 1988 to 71.7 percent in 1997 and the Powder River Basin share increased from 0 to 4 percent.

- Coal receipts in the Middle Atlantic region show a decline in the share coming from Northern Appalachia and an increase in the share coming from Central Appalachia. This shift was not caused by electric utilities complying with CAAA90, but was related more to growth in coal demand by independent power producers. In 1988, 12.3 percent of the coal shipped to Mid-Atlantic consumers came from Central Appalachia and by 1997 this share had increased to 19.5 percent. Over the same period, the share from Northern Appalachia declined from 87.7 percent to 80.0 percent.

- In the West South Central region, increased coal demand (primarily in Texas) was satisfied with Powder River Basin coal, reducing the share attributable to indigenous sources. This region did not have any plants affected by Phase I of the CAAA90.

Transportation Mode

Table 5 presents information on the shares of coal shipments by transportation mode. As shown, railroads are the leading transporters of coal in all demand regions, accounting in 1997 for nearly 62 percent of all coal shipments. Barge and truck shipments collectively accounted for slightly more than one-quarter of coal shipments in 1997, with the balance attributable to other transportation modes, including tramways and conveyors, as well as water-borne shipments on the Great Lakes and by tidewater.

Between 1988 and 1997, the most pronounced shifts in mode occurred in the East South Central, Mountain, and East North Central demand regions. In the East South Central region, the rail share of total shipments increased from 40.2 percent in 1988 to 47.2 percent in 1997. This shift occurred mostly at the expense of truck shipments, which declined in share from 21.5 percent to 15.7 percent, reflecting the shift in coal sources from Central and Southern Appalachia and the Illinois Basin to the Powder River Basin and the Rockies.

Similarly, the share of coal moving by rail to the East North Central region increased from 58 percent in 1988 to 63.4 percent in 1997, clearly reflecting the region's increased reliance upon coal from the Powder River Basin and the Rockies.

In the Middle Atlantic Region, the shares of coal moved by rail and by truck gained sharply between 1988 and 1993, largely as a result of decreased shipments by conveyor in the region. By 1997, however, the share of coal moving to the region by rail returned to roughly the level observed in 1988 as shipments by barge, and to a lesser extent by truck, gained market share.

In the Mountain region, the share of coal supplied by rail increased from 48.2 percent in 1988 to 56.6 percent in 1997 while the share supplied by other modes (primarily tramway) declined from 34.1 percent in 1988 to 25.5 percent in 1997. Most of this shift occurred between 1992 and 1993 and was attributable to a shift from tramway to rail for New Mexico coal supplied to power generators in New Mexico.

Table 5. Domestic Coal Distribution by Demand Region and Transportation Mode, 1988, 1993, and 1997

Region/Year	Total (Thousand Short Tons)	Percent of Total			
		Rail	Barge[a]	Truck	Other[a]
Middle Atlantic					
1988	70,253	37.7	25.8	21.6	14.9
1993	64,421	43.3	23.9	25.9	6.9
1997	76,486	37.9	27.8	27.0	7.3
East North Central					
1988	193,389	58.0	18.1	12.5	11.4
1993	196,343	58.3	18.2	13.9	9.6
1997	237,756	63.4	14.5	13.1	9.0
West North Central					
1988	112,365	65.0	6.3	6.6	22.0
1993	116,337	67.0	4.8	5.8	22.4
1997	131,682	67.3	8.2	5.2	19.3
South Atlantic					
1988	141,606	71.2	15.3	5.4	8.1
1993	141,701	71.4	16.8	5.5	6.3
1997	166,235	73.8	15.8	4.9	5.5
East South Central					
1988	85,737	40.2	32.9	21.5	5.3
1993	97,057	39.9	36.2	22.1	1.8
1997	108,477	47.2	33.6	15.7	3.5
West South Central					
1988	126,542	69.4	4.2	10.5	15.9
1993	139,664	68.8	4.8	12.0	14.4
1997	143,816	70.2	5.1	12.3	12.4
Mountain					
1988	104,271	48.2	0.0	17.7	34.1
1993	109,200	58.8	0.0	17.1	24.1
1997	113,045	56.6	0.0	17.9	25.5
U.S. Total					
1988	**853,930**	**57.5**	**13.5**	**12.3**	**16.1**
1993	**883,934**	**59.8**	**13.9**	**13.1**	**13.2**
1997	**995,181**	**61.8**	**13.7**	**12.3**	**12.2**

[a]"Barge" includes river and inland waterway shipments. "Other" includes Great Lakes and tidewater barges and colliers, tramways, conveyors, and slurry pipelines.

Notes: • U.S. total includes the New England and Pacific Census Divisions and coal for which the destination is unknown. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 65, pp. 126-127.

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3. Rail Coal Transportation Rates and Patterns

This chapter examines changes in transportation rates for contract coal shipped by rail from U.S. producers to investor-owned public electric utilities in the United States between 1988 and 1997. The statistics herein update those presented in EIA's earlier Interim Report[13] by (1) incorporating new data for the years 1994 through 1997, (2) supplementing the basic source data with information and data from other sources, and (3) researching and adding missing data elements in the pre-1994 database to enhance its usefulness. The focus of this chapter—the rail transport of coal—is the primary concern specified under Section 1340 of the Energy Policy Act of 1992.

Railroads constitute the mainstay of U.S. domestic coal distribution, delivering 61.8 percent of total coal distribution in 1997. Eighty-eight percent, or 875.7 million short tons (mst) of total domestic coal distributed, went to electricity generators at utilities (Table 1). This chapter focuses on those public electric utilities that are "investor-owned" because of the availability of representative data for those utilities on coal quality, tonnages, origins and destinations, and shipping rates collected in the Federal Energy Regulatory Commission (FERC) biennial interrogatory known as Form FERC-580.[14] (See Appendix A for specifics on Form FERC-580 and EIA's Coal Transportation Rate Database (CTRDB).)

Investor-owned utilities account for almost 80 percent of the coal-fired generation by public electric utilities. By the term "investor-owned utilities," EIA means to distinguish that class from public utilities that are Federal, State, or municipal entities—one of the major criteria used to specify utilities that are not required to submit fuels information or Form 580. Still, not all investor-owned public utilities are subject to Form 580 disclosure. The Form must be submitted only by "jurisdictional" utilities, that is, facilities subject to FERC jurisdiction on the basis of their sale or transmission of electricity across State lines. Further, only data related to coal purchased and delivered under supply contracts of more than 1 year's duration need be reported. Coal contracts of 12 months or less are considered spot market purchases, not subject to Form 580 reporting requirements. For that reason, Form 580 data on coal receipts are identified as "contract coal" data in this report.

Transportation analysts have shown that contract coal prices and rates are a valid indicator of changes in market conditions because contracts since the late 1980's include formulas to account for changes in economic conditions and supply and demand variables.[15, 16, 17] Nonetheless, the absence of spot market data, combined with a growing number of utilities not required to file fuel-related data on Form 580, resulted in full coverage of coal transportation data for only 35 percent of total domestic coal distributed to electric utilities as of 1997 (Appendix A).

In order to raise the level of data coverage, EIA supplemented the Form 580 database. Supplementary data and information for the CTRDB came primarily from the Surface Transportation Board (STB) "Annual Waybill Sample" (coverage is limited to rail shipments) and from the FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." Secondary information was derived from published industry reports and newsletters. The Waybill data and the FERC-423 data together may yield information on coal quality, delivered cost, tonnages, contract coal versus spot, origin and destination, waybill shipping rates,

[13] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597, (Washington, DC, October 1995), 136 pp.

[14] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Availability of Data and Studies*, DOE/EIA-0571, (Washington, DC, October 1993), pp. 3-12 and Appendix A.

[15] S.M. Dennis, "Using Spatial Equilibrium Models to Analyze Transportation Rates: An Application to Steam Coal in the United States," *Transportation Research Forum*, Vol. 35 (E) (1997), p. 147.

[16] P.L. Joskow, "The Performance of Long-Term Contracts: Further Evidence from Coal Markets," *Rand Journal of Economics*, Vol. 21(2) (1990), pp. 251-274.

[17] J.M. MacDonald, "Transactions Costs and the Governance of Coal Supply and Transportation Agreements," *Transportation Research Forum*, Vol. 34 (1) (1994), pp. 63-74.

shipping distances, carrier, and coal car ownership. Neither source includes f.o.b. minemouth coal prices or contract details. The Waybill data do not specify the customer. In some cases waybills include coal going to other nearby customers, so the data must be evaluated and edited carefully.

The waybill data apply only to commodities shipped by rail. Also, because it is a sample, waybill data were not available to characterize some "origin-destination pairs." In addition, some itineraries must travel via multiple railroads' trackage systems, so that locomotives from one railroad take over a train of loaded cars from locomotives of another railroad, making it infeasible to trace completely some recurring coal shipments. In all cases in this report, FERC-580 and STB Waybill Sample information designated as confidential is either presented in aggregated form to protect the confidentiality of individual respondents or is withheld.

Overall transportation trends for U.S. coal are presented in the next section, followed by examination of trends in coal supplied to defined demand regions, coal supplied to electric utilities affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90), and coal originated in defined supply regions.

Overall Trends in U.S. Rail Coal Transportation, Sulfur Levels, and Rates

Three major trends define the changes in contract coal transportation by rail during the1988-1997 study period: total tonnage shipped, low-sulfur coal distribution, and high-sulfur coal distribution.[18] The quantity of contract coal shipped by rail to electric utilities rose from 269.6 to 366.2 million short tons (mst). That is an increase of 36 percent, or a 3.1 percent annual average over the 10-year period (Table 6). As noted in Chapter 2, that rise correlates with increased capacity utilization at the Nation's coal-fired power plants during the period.

Table 6. Tons of Contract Coal Shipped by Rail, by Sulfur Category, 1988-1997

Year	Tonnage (million short tons)	Percentage Distribution			
		Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	269.6	48.4	26.6	7.2	17.7
1989	272.8	50.1	23.5	9.5	16.9
1990	315.6	43.1	32.1	8.6	16.2
1991	305.7	47.7	28.6	8.2	15.6
1992	282.0	50.2	24.3	9.4	16.0
1993	282.8	57.8	23.7	7.3	11.3
1994	368.9	56.3	25.3	7.2	11.3
1995	370.7	61.2	24.7	4.6	9.5
1996	334.1	62.9	23.3	5.4	8.4
1997	366.2	64.9	23.8	3.7	7.5

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium-Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Percentages may not sum to 100 because of independent rounding. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

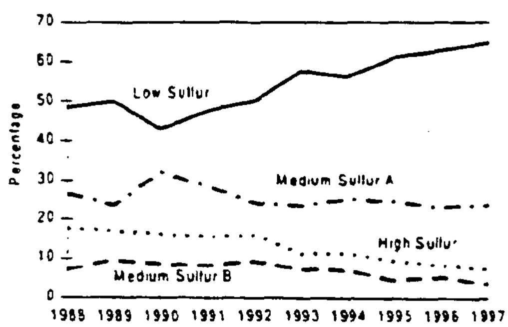
[18] High-sulfur coal contains more than 1.67 pounds of sulfur per million Btu of heat input. Low-sulfur coal is defined as containing 0.6 or less pounds of sulfur per million Btu, which meets the Phase II emission limit of 1.2 pounds of sulfur dioxide per million Btu. This category was identified as "compliance coal" in the Interim Report. The term "compliance coal" is widely used because 0.6 pounds of sulfur per million Btu is the upper limit sulfur content that complied with emission limits defined for New Source power plants under the Clean Air Act of 1971. Since publishing the Interim Report, ELA unified its coal classifications, such that the criteria for low-sulfur and compliance coal coincide.

Coal Sulfur Levels

As contract coal shipments by rail increased, the portion represented by low-sulfur coal grew most rapidly, from 48 percent in 1988 to 65 percent in 1997. During that time, the share for high-sulfur coal shrank from 18 percent to 8 percent of all contract coal shipped by rail (Table 6). The increases in market share for low-sulfur coal did not begin with the CAAA90, but the rate of increase did double in the 1988-1997 period. Prior to any effects of that legislation, the 48 percent share of rail distribution claimed by low-sulfur coal in 1988 had risen from a 27 percent share in 1979, based principally on requirements of earlier clean air legislation (CTRDB 2000).[19]

Although not as pronounced as the trend for high-sulfur coal shipments, the amounts of relatively sulfurous "medium-sulfur B" coal shipped decreased also (Figure 5). Distribution remained level for "medium-sulfur A" coals.[20] These were the highest-sulfur coals that could be burned after January 1, 1995, without treatment or penalties, at power plants affected by Phase I of CAAA90. Figure 5 clearly illustrates the divergence between the distribution levels of low-sulfur coal and those of the other coal categories.

Figure 5. Percentage Distribution of Contract Coal Shipped by Rail, by Sulfur Category, 1988-1997



Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Percentages may not total 100 because of rounding.

Source: Energy Information Administration, Coal Transportation Rate Database.

Coal Transportation Distances

The average distance contract coal is shipped by rail rose from 640 miles in 1988 to 793 miles in 1997 (Table 7). Most of this increase of 23.9 percent was driven by the rising share of coal distribution comprised by low-sulfur coal. During the study period, low-sulfur coal originated primarily in the Powder River Basin of Wyoming and Montana, followed distantly by Central Appalachia and the Rockies Region (Utah and Colorado). By 1997, 86 percent of all low-sulfur coal delivered originated in the Powder River Basin and Rockies supply regions, far from most of the large coal-burning utilities. Thus, the average distances compiled in Table 7 for low-sulfur coal are largely averages of the various routes from Wyoming, Montana, Utah, and Colorado to customers to the east and south.

Despite the inroads made by Western low-sulfur coals into the Midwest, the Southwest, and some Southeastern States during the 1980's and early 1990's, the actual distances low-sulfur coal is transported have increased very little, if at all. As a result of the greater proportion of total coal receipts that originate in distant low-sulfur supply areas (Figure 5), however, the average distance for U.S. coal distribution overall did increase (Figure 6).

When graphed for individual coal types, distribution distances remain relatively flat from 1988 through 1997. Only high-sulfur coal shows a general upward trend, however slight, which reversed after 1995 (Figure 6). This reversal results from a reduction after Phase I, among power plants located in or near high-sulfur coalfields, in coal purchases from nearby, often in-State, high-sulfur mines. For example, in the generally high-sulfur coal States of Ohio, Illinois, and Indiana, 52.2 mst of in-State contract coal was shipped to power plants in 1994, the final year preceding Phase I. That figure declined to 46.4 mst in 1995 and to 37.5 mst in 1996

[19] "CTRDB 2000" is an acronym/abbreviation used to indicate that the statistics cited were drawn from the primary source data for this report, the Coal Transportation Rate Database, update version of August 10, 2000. The full citation is: Coal Transportation Rate Database, August 10, 2000 (Electronic database, 2000). Energy Information Administration (EIA), Washington, DC. (Distributor: EIA, http://www.eia.doe.gov/cneaf/coal/page/database.html).

[20] Medium-sulfur A coal was termed "low-sulfur coal" and medium-sulfur B coal was simply "medium-sulfur coal" in the Interim Report, prior to EIA's unified classification. Medium-sulfur coal statistics were split into two categories to distinguish medium-sulfur A coal which could be burned without further adjustments, after January 1, 1995, from coal that cannot (i.e., medium-sulfur B and, of course, high-sulfur coal).

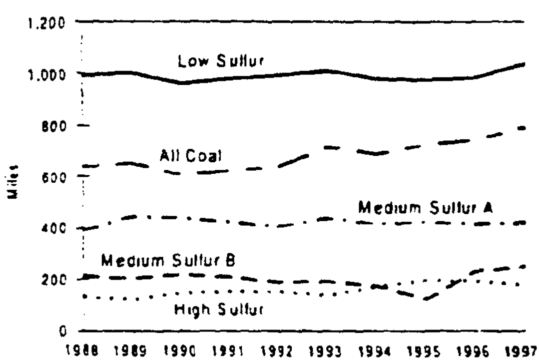
Table 7. Average Distance of Contract Coal Rail Shipments by Rail, by Sulfur Category, 1988-1997
(Miles)

Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	640.2	993.5	439.7	224.8	133.7
1989	653.4	1,004.7	444.2	203.4	121.1
1990	606.7	963.2	438.1	220.0	148.4
1991	623.1	982.1	422.5	208.8	154.4
1992	638.8	994.6	403.8	187.3	151.3
1993	715.5	1,012.0	438.2	191.2	138.7
1994	687.8	980.6	414.1	174.9	172.8
1995	725.9	977.3	422.7	124.6	195.8
1996	743.1	986.2	414.0	233.5	194.3
1997	793.5	1,037.7	419.0	251.0	180.2

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

Figure 6. Average Distance of Contract Coal Shipments by Rail, 1988-1997



Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu.

Source: Energy Information Administration, Coal Transportation Rate Database.

before recovering at 42.0 mst in 1997. At the same time, turning to sources for lower-sulfur coal inevitably meant increased shipping distances (CTRDB 2000).

Coal Transportation Rates

Contract coal transportation rates for rail deliveries vary among different pairs of origins and destinations and with factors such as distance, coal tonnage, and length of contract. In this section, averaged data and general trends are described. Variations among U.S. coal demand and supply regions are discussed in the next section, Regional Trends in U.S. Rail Coal Transportation, Sulfur Levels, and Rates.[21]

Dollars per Ton

The average inflation-adjusted rate per ton to ship contract coal by rail fell steadily during the study period—a decline of 25.8 percent from 1988 through 1997 (Table 8). The rates for coal in all sulfur categories trended downward, despite a significant reversal in the rates for medium-sulfur B coal in 1996 and 1997 (Figure 7).

[21] Because the rate data in this report represent regional data aggregations, they do not address alleged inequities in rates to and from isolated locations, or for "captive" shippers (with only one practical coal transportation option), or for small shippers who may not have access to technologically efficient loading equipment or may not qualify for high volume discounts.

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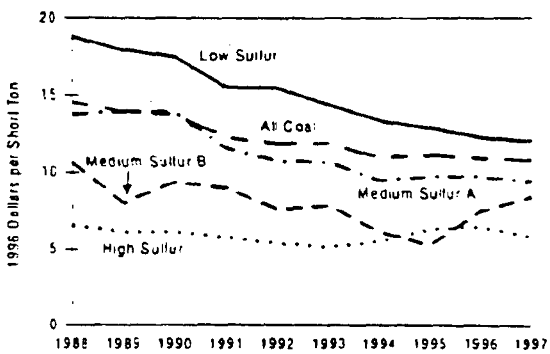
Table 8. Average Rate per Ton for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997
(1996 Dollars per Short Ton)

Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	14.56	18.82	13.77	10.64	6.57
1989	13.95	17.97	13.94	8.03	6.13
1990	13.74	17.51	13.89	9.38	6.14
1991	12.26	15.53	11.58	8.99	5.77
1992	11.88	15.49	10.75	7.59	5.36
1993	11.92	14.36	10.67	7.87	5.16
1994	10.97	13.40	9.49	6.15	5.52
1995	11.13	12.92	9.74	5.27	6.31
1996	10.96	12.32	9.76	7.50	6.47
1997	10.81	12.05	9.41	8.43	5.83

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

Figure 7. Average Rate per Ton for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997



Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds of sulfur per million Btu; High Sulfur = greater than 1.67 pounds per million Btu.

Source: Energy Information Administration, Coal Transportation Rate Database.

Clearly, the majority of the contract coal shipped by rail during this period traveled via lower real-dollar rates than in earlier years, and there is no evidence of widespread inflation of shipping rates by the major coal-hauling railroads following enactment of the CAAA90.

In fact, the greatest decline in coal rail rates per ton—a 36.0 percent decline in constant dollar terms—was for low-sulfur coal, the very category over which concern may have been greatest.

The circumstances contributing to each rise in rates for medium-sulfur coal are not known, but an underlying issue is the smaller coal volumes shipped. Referring back to Table 6, medium-sulfur B contract coal shipments fell by 49 percent from 1994 to 1997. This means that the average number and/or size of new contracts were diminishing for coal that would require use of emission allowances or post-combustion scrubbing after January 1995, no matter where it was burnt. Expiring contracts were not being replaced and many existing contracts had been bought out. The average annual tonnage of medium-sulfur B contract coal transported by rail diminished from 26.5 to 13.7 mst between 1994 and 1997,and the average rate per ton rose from $6.15 in 1994 to $8.43 in 1997 (Table 8).

The rates for high-sulfur coal under contract declined only slightly during the CAAA90 study period. On the other hand, their rail tonnages fell by 57.5 percent from 1988 to 1997, but did not exhibit a decline in 1994, just before the Phase I requirements went into effect. No downturn occurred in 1994 because some power plant operators had committed to the use of high-sulfur coal prior to the beginning of Phase I. These included operators at high-polluting Phase I-affected plants[22] and at plants already in compliance under earlier, tighter emission standards. Whether compliance with the CAAA90 would be through construction of flue gas scrubbers or through buying or trading of emission allowances, those decisions had been implemented gradually, starting prior to 1995. Power plants not affected by Phase I had until January 2000 to plan and initiate any further sulfur dioxide mitigation measures.

Mills per Ton-Mile

The transportation rate per ton-mile is the rate per ton of coal per mile shipped. To obtain significant whole numbers, rail rates per ton-mile are scaled in mills (tenths of a cent) per mile.

Like the average rate per ton, the average rate per ton-mile to ship contract coal by rail declined steadily during the study period. The real-dollar rates for coal in all sulfur categories trended downward (Table 9). The ordering of the rates for coal by sulfur categories shown in Figure 8 is essentially the reverse of those in Figure 7. For example, low-sulfur coal had the highest shipping rate per ton but its rate per ton-mile was the lowest of all. This reversal reflects the fact that low-sulfur coals were located far from most major consumers. Low average rates per ton-mile are found where shipping distances are greater because the fixed costs and loading and unloading costs of carriers are spread over more miles in the net rate calculation. The average rates per ton-mile for high-sulfur coal, on the other hand, were relatively high during the period, while its rates per ton were the lowest on average. These relationships reflect a coal which, while losing market share (Table 6), is concurrently losing customers, especially among traditional customers in the areas where it is mined.

The rail rates per ton-mile were erratic for medium-sulfur B coal—even more than the rates in dollars per ton, and especially from 1993 through 1996 (Figure 8). Rapid changes took place in the rate per ton-mile for medium-sulfur B coal as many customers changed suppliers during the CAAA90 study period. In some cases, as rates per ton were falling, rates per ton-mile rose, as in 1995 and 1996 and less dramatically from 1990 through 1992. In a stable supplier-consumer environment, rising rates may signify higher rail tariffs due to lack of competition. However, the steep rise in the average rate per ton-mile in 1995, which took place when utilities were changing coal suppliers, occurred because average shipping distances had declined at that

Table 9. Average Rate per Ton-Mile for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997
(Mills per Ton-Mile in 1996 Dollars)

Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	23.2	19.1	30.9	45.7	51.0
1989	21.6	18.0	30.5	39.6	48.3
1990	21.9	18.3	27.9	36.5	40.7
1991	20.3	16.5	27.6	36.6	40.0
1992	19.0	15.7	27.4	38.9	36.0
1993	16.9	14.2	25.5	40.3	37.0
1994	16.0	13.6	23.2	34.7	31.8
1995	15.4	13.2	23.4	42.3	31.7
1996	14.8	12.5	23.6	32.1	33.4
1997	13.6	11.6	22.5	33.6	32.4

Notes: • One mill equals 0.1 cent. • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

[22] The CAAA90 listed by name 263 boilers at 261 previously exempted generators that would be required to meet Phase I emission requirements. These were referred to in subsequent Environmental Protection Agency regulations as "Table 1" units, along with 174 additional generating units the utilities brought into Phase I as substitution and compensating units.

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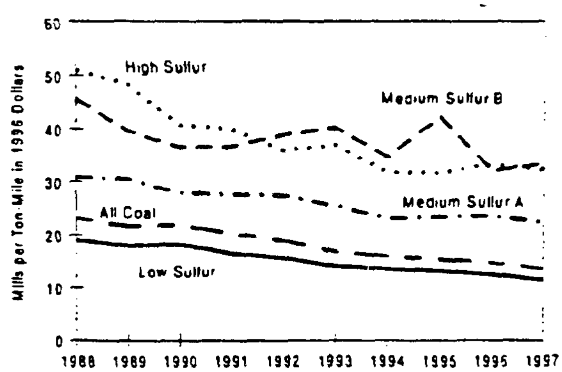
Figure 8. Average Rate per Ton-Mile for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997



Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu.

Source: Energy Information Administration, Coal Transportation Rate Database.

time. Rail contracts for medium-sulfur B, which had supplied 26.5 mst of coal in 1994, accounted for only 17.1 mst in 1995, while the average shipping distance shrank from 174.9 to 124.6 miles (Tables 6 and 7). Further, contract tonnage for this coal rose from 17.1 mst in 1995 to 18.2 mst in 1996, then declined to 13.7 mst in 1997, indicating that the increase in average distance shipped was coupled with a modest increase in new contracts in 1996, followed by more loss in market share in 1997 (Table 7).

Transportation Cost as a Percentage of Delivered Price

Between 1988 and 1997 a consistent 49 to 52 percent of the rail-delivered price of low-sulfur contract coal was spent to transport it. By comparison, transportation costs of the other coal types trended higher, reaching 29 percent in 1997 for the delivered price of medium-sulfur A coals, 26 percent for medium-sulfur B coals, and only 22 percent for high-sulfur coals (Table 10). The stable ratios of transportation costs to delivered price for low-sulfur coal reflect a balance between declining minemouth coal prices and declining western rail transportation rates throughout most of the 1990's (Figure 9). The ratios for the medium- and high-sulfur coals rose because the average minemouth prices of these coals declined. The rail rates per ton declined also, but not as rapidly as coal prices in the unsparingly competitive coal industry.

In general, the higher the sulfur content of the coal, the smaller is the portion of delivered price made up by

Table 10. Transportation Cost as a Percentage of Delivered Price for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997

Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	33.9	50.3	26.9	23.5	15.0
1989	34.6	51.8	28.2	18.5	14.7
1990	35.5	51.0	20.8	20.8	15.6
1991	32.5	48.8	25.6	20.1	15.6
1992	33.6	50.0	25.6	18.5	15.3
1993	36.7	50.8	27.3	20.6	15.4
1994	35.4	50.2	24.5	18.1	16.7
1995	38.2	50.8	26.1	16.8	20.4
1996	40.1	51.7	28.2	22.5	21.6
1997	41.0	51.3	28.5	26.1	21.5

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

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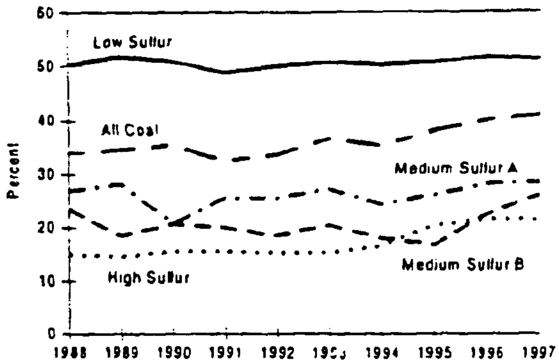
Figure 9. Transportation Cost as a Percentage of Delivered Price for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997



Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu.

Source: Energy Information Administration, Coal Transportation Rate Database.

transportation costs. Thus, among all coal shipments, the lowest average distances over the years are for high-sulfur coal and the average rates per ton are therefore relatively low. This accounts both for high-sulfur coal having the lowest transportation cost as a percentage of delivered price and for it having the highest rate per ton-mile.

Transportation rates, however, are not the only variables affecting the ratio of transportation cost to delivered price. The other variable—the other factor that makes up delivered cost—is the minemouth price of the coal. In the case of low-sulfur coal, the average minemouth price in 1997 was only $10.52 per short ton (CTRDB 2000), owing to the predominance of low-Btu subbituminous Powder River Basin (PRB) coal with extremely low mining costs and an average selling price of $5.67 per short ton. By contrast, low-sulfur coal from Central Appalachia, which is thinner bedded and more expensive to mine, sold for an average of $27.87 per short ton at the mine in 1997, with an average transportation rate of $9.96 per ton (Table 11).

The 1997 average delivered costs of the Central Appalachia coal are nearly double those of PRB coal, but are only 26 percent higher than PRB costs when the much higher heat content of Central Appalachia coals is factored in (Table 11). Rockies region coal, which is also largely bituminous coal similar in heat content to Central Appalachia's, was delivered at only 10 percent more than PRB coal in 1997, on a cost per million Btu basis. Considering individual boiler efficiencies and lower ash production, therefore, Central Appalachia and Rockies region coals are competitive with PRB coals for many utilities when heat content is accounted for in bottom-line costs.

The decline in average contract coal rail rates during the study period was a response to competitive markets but it was not a spontaneous process. Both western railroads and western mine operators had taken the initiative during the late 1980's and early 1990's to develop markets to the east and south. It had been widely acknowledged that huge reserves of low-sulfur, low-Btu coal were in the ground in the PRB, but potential customers had little evidence that producers would offer competitive prices. Also, considering the lower heat value of the coal compared with eastern bituminous, could the delivery rates be reduced enough to make the coal worth shipping, and would the infrastructure be adequate to meet demand?

Western railroads answered by expanding capacity and investing in equipment and infrastructure—moves clearly meant to persuade midwestern and Sunbelt electricity generators that the low-sulfur coal reserves in the PRB, and in the Rockies, would be reliable sources. Coal rail rates were kept low. Because of the increased distances, even with competitive transportation rates, railroads stood to increase revenues by persuading utilities to switch to low-sulfur western coals in order to meet Phase I requirements and, eventually, Phase II pollution limits. Concurrently, PRB and Rockies coal producers offered very competitive coal prices and worked with customers to innovate mutually beneficial three-point hauls and ash haulback arrangements for power plants with on-site disposal limitations.

In a system in which sulfur dioxide emissions are constrained, it could be expected following the enactment of CAAA90 that reliable supplies of low-sulfur coal would command premium prices—as indeed they had in the previous decade. Instead, western coal producers capitalized on economies of scale available in the West and continued to offer their product at ever more competitive prices. With thick coalbeds, thin overburden, and space for support facilities, mines in the PRB could use huge equipment and the most efficient mining technologies to produce great tonnages of coal cheaply. In some other western coalfields, mountainside or canyon floor access permitted use of "drift" mines, which are less costly to develop than vertical shaft mines. In some, large mining blocks of thick coalbeds

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Table 11. Low-Sulfur Coal Cost Variables for Contract Coal Shipments by Rail 1988, 1993, and 1997

Major Supply Region	Cost Variables (1996 dollars)	1988	1993	1997	Percent Change 1988 to 1997
Powder River Basin	Average Minemouth Price per ton	13.08	9.09	5.67	-56.7
	Average Transportation Rate per ton	19.65	14.40	12.70	-35.4
	Average Delivered Cost per ton	33.87	23.92	20.52	-39.4
	Average Transportation Rate in cents per MBtu	96.5	85.7	72.3	-25.1
	Average Delivered Cost in cents per MBtu	193.4	171.0	149.1	-22.9
Central Appalachia	Average Minemouth Price per ton	39.30	32.46	27.87	-29.1
	Average Transportation Rate per ton	16.63	12.05	9.96	-40.1
	Average Delivered Cost per ton	55.43	44.83	39.10	-29.5
	Average Transportation Rate in cents per MBtu	65.1	46.5	39.8	-47.7
	Average Delivered Cost in cents per MBtu	217.8	208.9	188.3	-27.4
Rockies	Average Minemouth Price per ton	31.41	22.87	18.50	-41.1
	Average Transportation Rate per ton	18.45	14.30	10.15	-45.0
	Average Delivered Cost per ton	48.82	37.52	29.34	-39.9
	Average Transportation Rate in cents per MBtu	82.2	34.0	51.9	-36.9
	Average Delivered Cost in cents per MBtu	217.1	158.1	164.7	-24.2

MBtu = Million Btu.

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu. • Average delivered cost may not equal the sum of average minemouth price and average transportation rate because one or more of the values may be missing from some records, making different record counts for each variable.

Source: Energy Information Administration, Coal Transportation Rate Database.

were available for highly productive "longwall" underground mines, and sparsely populated surface lands meant fewer concerns over ground subsidence than in the East. Further, in the late 1970's and into the 1980's, some utilities had signed long-term contracts with PRB mines for low-sulfur coal at what later became greatly above-market prices. Older PRB mines with such contracts, some of which have yet to expire, were able to operate with the profits from those contracts while securing new customers with ever lower mine prices and/or delivered prices.

Railroads serving the PRB also took advantage of inherent economies of scale. Rail rates from the PRB could be held down, on a cost per ton-mile basis, because the flat terrain and space for loading facilities allow efficiencies throughout the haul. The unit trains from the PRB are some of the longest and comprise some of the highest-capacity bulk railcars in the United States, and they can be efficiently loaded and unloaded at uncrowded, modern facilities.[23]

It was western coal producers and railroads, each competing aggressively to win new markets, who forced coal prices and rail rates downward throughout the country by offering ever lower delivered prices for reliable supplies of low-sulfur coal. In Appalachia, where mining conditions are more challenging, coal producers could not possibly match minemouth prices at PRB and many Rockies mines. Many smaller, less efficient mines closed and the industry offered lower prices by consolidating around fewer, larger, more productive mines with modernized technologies. Eastern railroads lowered their rates also as, even with lowered minemouth prices, the delivered costs were higher than for western coals. It was either lower rail rates or the eastern railroads would have been party to closings of the larger mines and loss of some of their major clients and revenue sources. Table 10 illustrates that both components of competitive coal pricing declined in the three low-sulfur regions—average minemouth price and average transportation rate, with consequent declines in the average delivered price of coal. Similar reductions in cost

[23] STB Waybill data indicates averages ranging from 106 to 117 cars in unit trains originating in the Powder River Basin. Union Pacific Railroad reports PRB trains in 1999 routinely hauling 110 to 115 cars, or 135 cars with distributed power (one locomotive positioned within the train of cars). The average carload has increased over recent years as more large-capacity aluminum gondolas are used. The average PRB carload was 112.5 tons in 1997 and 113.5 tons in 1999. (Duane Anderson, Union Pacific Railroad Company, Accounting Group, via letter and personal communication, October 7, 1998 through August 22, 2000.)

components and delivered prices followed suit for coal with higher sulfur levels, again, in order to compete and to retain at least a smaller share of coal sales.

Transportation Rates per Million Btu

Coal transportation costs on the basis of the heat content and the sulfur content of the fuel delivered are indicative for many, but not all, electric power producers of the net value of the coal for their purposes. From the customer's perspective, the two most important attributes of any steam coal are: the delivered price of the coal and its value to the customer for use as a fuel. This report is not about delivered prices of coal, even though those data were useful to calculate apparent net transportation rates if rates were otherwise not reported.

The value of a coal to electric power producers currently and in recent years depends primarily on the two coal characteristics that govern its performance and its sulfur dioxide emissions—heat content and sulfur content. Those two coal characteristics are basic. Along with minemouth price, rate per ton, and rate per ton-mile, they affect the bottom-line costs the utility incurs in generating kilowatts. The decisions on heat and sulfur content and other coal specifications have to be made early on, however, so that combustion and emissions technologies can be installed and tested. For that reason, utility fuels buyers negotiate at both the mine level and the transportation level to secure the best buy available for their fuel specifications, including alternate suppliers, alternate fuels in some cases, and alternate modes of delivery.

In most cases, low-sulfur coals offer a better value to power producers. That is, compared with purchasing allowances or investing in flue gas scrubber, the lowest cost option for the greatest number of utilities was found to be switching from high-sulfur to low-sulfur coal.[24] In some cases, however, a power producer's strategy may include medium- or high-sulfur coal: for example, if scrubbers are already capitalized and being used; if emissions are being offset at other, newer plants; or if because of a plant's age, it is cheaper to purchase the needed emission allowances. In those circumstances, coal purchasers may reckon the value of coals for their operation based more on Btu content, ash content and implied ash disposal options, and factors that affect boiler performance or slagging such as coal volatility, ash fusion temperature, or sodium content.

Changes in the transportation rates per million Btu and by sulfur content of contract coal delivered to electric utilities are the cost variables in this report that best describe the factors critical to the majority of electricity-generating customers (Table 12). Low-sulfur coal

Table 12. Average Rate per Million Btu for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1998
(Cents per Million Btu in 1996 Dollars)

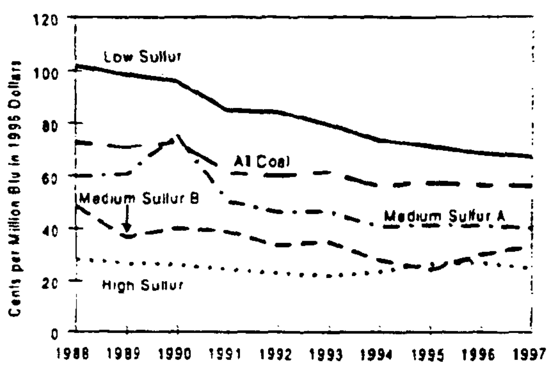
Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	72.9	101.9	59.8	48.7	28.3
1989	70.8	98.6	60.6	36.5	26.6
1990	72.9	96.1	75.2	40.3	26.0
1991	61.0	84.8	50.1	38.6	24.3
1992	59.7	84.2	46.0	33.3	22.7
1993	61.1	79.1	46.1	34.6	21.7
1994	55.8	73.3	40.4	27.6	23.1
1995	57.1	71.1	41.2	24.0	26.3
1996	56.3	68.3	40.9	29.8	26.8
1997	56.0	67.0	39.9	33.1	24.4

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.
Source: Energy Information Administration, Coal Transportation Rate Database.

[24] Energy Information Administration, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities* (DOE/EIA-0582 (97)) (Washington, DC, March 1997), pp. 12-13.

consistently had the highest average transportation rates per million Btu during the study period. As noted earlier, the low-sulfur coals being shipped during the 1980's and 1990's were overwhelmingly low-Btu subbituminous coals from the Powder River Basin. Their low Btu levels, coupled with greater shipping distances than eastern coals, kept transportation rates high on a cents-per-million-Btu basis (Figure 10).

Figure 10. Average Rate per Million Btu for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997



Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu.

Source: Energy Information Administration, Coal Transportation Rate Database.

Further, there is no evidence that rail rates for low-sulfur coal became less competitive in terms of delivered Btu content during the CAAA90 study period. All rail transportation rates by Btu for coal declined between 1988 and 1997. The low-sulfur rates actually declined slightly more: by 34.2 percent, compared with 33.3 percent for medium-sulfur A and 32.0 percent for medium-sulfur B coal. The rate per million Btu for high-sulfur coal declined the least, by only 13.8 percent. However, the high-sulfur coals delivered were typically high-Btu coals and the shorter shipping distances for high-sulfur coals during the study period (Table 7), combined with the high-Btu levels, resulted in initially low cents per million Btu shipping rates and relatively less change in the net rate (Table 12).

Regional Patterns and Changes in U.S. Rail Coal Transportation

In Chapter 2, nine coal demand regions were established based on U.S. Census Divisions (see Table 1 and Figure 1). Of those nine, seven coal demand regions in 1997 received 98.4 percent of total coal distribution (Table 1). In this section, therefore, the 1.6 percent of U.S. coal distributed to the New England and the Pacific (combined contiguous and non-contiguous States) demand regions is considered irrelevant to major coal transportation trends and are excluded from regional tables and figures.

Likewise, eleven coal supply regions were defined that account for domestic coal production and its distribution (Figure 2 and Table 3). Of those eleven, five regions were the source of 84.6 percent of total coal distribution in 1997—Northern Appalachia, Central Appalachia, Illinois Basin, Powder River Basin, and Rockies. These five major coal supply regions are included in the regional tables and figures in this section. The other six regions—Southern Appalachia, Gulf Coast Lignite, North Dakota Lignite, Southwest, Northwest, and Other Western Interior—are excluded from the tables and figures for two reasons. First, most of the coal in regions such as Gulf Coast Lignite, North Dakota Lignite, and Northwest is consumed at minemouth powerplants; any delivery costs are included in the price of the coal. Second, the number of companies operating mines in these six regions that do ship coal is so few that confidential rate data would have to be withheld in virtually every case, even within regional aggregations.

Demand Regions - Contract Coal Transportation by Rail

This section includes analyses of coal transportation infrastructure, rates, and distribution patterns for each of the seven major demand regions and the five major supply regions. The focus of the analysis is rail distribution of coal. Established coal transportation patterns in each region represent the framework within which changes related to the EPACT would take effect. Summaries of changes in the rail transportation rates for coal appear in matrix form in Table 13, for rates per ton, and in Table 14, for rates per ton-mile. The reasons behind these changes are discussed in regional summaries in the following sections. In order that statistics on rail-delivered contract coal be viewed in functional context, each summary includes background information and statistics on the region's overall coal transportation system.

As noted earlier (Table 8), the overall trend in rail rates per ton of coal delivered was down by 25.8 percent from 1988 to 1997. No demand region broke with that trend. Indeed, what is discovered in comparing the regional and rate data in Tables 13 and 14 is that two

Table 13. Average Rate per Ton for Contract Coal Shipments by Rail Between Selected Supply and Demand Regions, 1988, 1993, and 1997
(1996 Dollars per Ton)

Demand Region	Supply Region				
	Northern Appalachia	Central Appalachia	Illinois Basin	Powder River Basin	Rockies
Middle Atlantic					
1988	15.48	W	--	--	--
1993	9.76	W	--	--	--
1997	11.54	W	--	--	--
Percent Change 1988-1997	-25.45	-38.29	--	--	--
East North Central					
1988	8.75	16.50	4.76	23.53	W
1993	W	13.67	3.30	15.39	W
1997	8.25	11.59	3.58	11.75	W
Percent Change 1988-1997	-5.71	-29.76	-24.79	-50.06	-59.46
West North Central					
1988	--	--	W	14.16	--
1993	--	--	6.83	11.58	W
1997	--	W	W	9.84	W
Percent Change 1988-1997	--	--	-36.18	-30.51	--
South Atlantic					
1988	11.08	14.99	--	--	--
1993	10.63	12.56	--	--	--
1997	10.85	10.34	W	W	--
Percent Change 1988-1997	-2.08	-31.02	--	--	--
East South Central					
1988	--	10.21	3.90	--	--
1993	--	6.84	4.45	--	--
1997	--	6.41	4.08	W	W
Percent Change 1988-1997	--	-37.22	4.62	--	--
West South Central					
1988	--	--	--	23.89	W
1993	--	--	--	17.97	W
1997	--	--	--	15.40	--
Percent Change 1988-1997	--	--	--	-35.54	--
Mountain					
1988	--	--	--	W	14.87
1993	--	--	--	6.86	9.86
1997	--	--	--	W	8.02
Percent Change 1988-1997	--	--	--	-39.59	-46.07

Note: Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.
W = Withheld to avoid disclosure of confidential data.
-- = Not applicable.
Sources: Energy Information Administration, Coal Transportation Rate Database.

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Table 14. Average Rate per Ton-Mile for Contract Coal Rail Shipments Between Selected Supply and Demand Regions, 1988, 1993, and 1997
(Mills per Ton-Mile in 1996 Dollars)

Demand Region	Supply Region				
	Northern Appalachia	Central Appalachia	Illinois Basin	Powder River Basin	Rockies
Middle Atlantic					
1988	41.3	W	--	--	--
1993	40.1	W	--	--	--
1997	34.6	W	--	--	--
Percent Change 1988-1997	-16.22	-54.11			
East North Central					
1988	32.2	39.6	45.5	19.6	W
1993	W	28.8	42.4	11.9	W
1997	24.5	27.7	34.4	9.4	W
Percent Change 1988-1997	-23.91	-30.05	-24.40	-52.04	-60.24
West North Central					
1988	--	--	W	18.4	--
1993	--	--	42.7	13.5	W
1997	--	W	W	11.9	W
Percent Change 1988-1997	--	--	6.11	-35.33	--
South Atlantic					
1988	69.8	33.0	--	--	--
1993	42.4	27.9	--	--	--
1997	36.4	23.0	24.1	W	--
Percent Change 1988-1997	-47.85	-30.30	--	--	--
East South Central					
1988	--	27.8	48.9	--	--
1993	--	23.3	38.9	--	--
1997	--	31.4	32.0	W	W
Percent Change 1988-1997	--	12.95	-34.56	--	--
West South Central					
1988	--	--	--	16.9	W
1993	--	--	--	13.6	W
1997	--	--	--	11.7	--
Percent Change 1988-1997	--	--	--	-30.77	--
Mountain					
1988	--	--	--	W	36.2
1993	--	--	--	23.8	29.3
1997	--	--	--	W	19.7
Percent Change 1988-1997	--	--	--	-22.31	-45.58

Note: Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enahanced with new and supplementary data, including data for years prior to 1995.
W = Withheld to avoid disclosure of confidential data.
-- = Not applicable.
Sources: Energy Information Administration, Coal Transportation Rate Database.

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underlying factors largely control rail rates: distance and volume.

Those demand regions that received coal from the Powder River Basin (PRB) or the Rockies supply region registered the greatest reductions in dollar-per-ton rates. Certainly, the rates from those two regions on a per-ton basis were high to begin with, so they had greater potential for reductions. The average declines in rail rates to the East South Central region were relatively modest largely because it did *not* include shipments from the PRB and Rockies (Table 4), with their above-average rate declines, throughout the study period. Coal from these two regions travel the greatest average distances and are supplied under relatively large-volume contracts (CTRDB 2000), and greater tonnages in the contracts won shippers incremental rate reductions. Contracts often include tiered rate provisions that reward the shipper with lower rates for tonnage shipped above the contracted minimum.[25] Greater distances reduce the rate per ton-mile (Table 14) as fixed costs are applied over a greater mileage.

Contract coal transportation rates trended downward in nearly every demand and supply region. Most coal rates declined primarily as part of the general lowering of rail shipping rates during the study period. Secondarily, variations in coal rates in a demand region were affected by its supply region options. For example, coal transported to the South Atlantic and the East South Central demand regions included average rates that declined very little or actually increased. In both cases, the higher average rates (Table 13) were associated with supply regions—Northern Appalachia and the Illinois Basin—with declining volumes of coal shipments (Table 4). Further, the average distance of the reduced coal shipments became longer, as indicated by the decreased rates per ton-mile (Table 14). Those circumstances indicate a loss in total coal shipments from those regions, especially from short-haul customers located in or near the supply regions.

Middle Atlantic Demand Region
(Pennsylvania, New York, and New Jersey)

Traditionally, Appalachian coal is burned in the Middle Atlantic demand region, primarily from Pennsylvania, Ohio, and northern West Virginia, with lesser amounts from Central Appalachia. Extensive infrastructure for both rail and barge connect this demand region with nearby Northern Appalachian and more distant Central Appalachian coalfields. Rail transportation is the leading mode.

Barge-only transportation, originating mostly in western Pennsylvania and northern West Virginia, is limited to customers along the Ohio River and its tributaries in western Pennsylvania (corridors of the so-called "rust belt" of the 1970's). Nonetheless, at times in the late 1970's and early 1980's, barge tonnages exceeded rail for contract coal. Multimode shipping, originated by rail mostly in western Pennsylvania and northern West Virginia and transferred to barge for the final legs, figures intermittently in coal shipments to coastal New Jersey and to Great Lakes docks in New York. Occasionally, for contracts in the western part of the Middle Atlantic region, conveyor systems play a significant role in coal transportation from nearby mines.

Coal-fired power plants in the Middle Atlantic region were not typical of average conditions nationally. As noted in Chapter 2 (Table 2), total domestic coal receipts at electric utilities in the region fluctuated between 1988 and 1997, but increased by a slight 2.2 mst for the period. During those years, rail shipments of coal to investor-owned electric utilities in the CTRDB likewise fluctuated, rising by 2.3 mst in the end (Table 15).[26] Rail shipments represented about 40 percent of coal distribution to this region (Table 5).

CTRDB electric utilities received less, rather than more rail-shipped low-sulfur coal from 1988 to 1997 (Table 15) because affected boilers had installed flue-gas scrubbers or arranged for emission allowances to comply with Phase I of CAAA90. Based on CTRDB file data for all transport modes, investor-owned utilities received 35.8 million short tons (mst) of Northern Appalachian coal (medium- to high-sulfur) in 1988 and 30.7 mst in 1997. Central Appalachian (mostly low-sulfur) coal deliveries declined from 2.3 to 0.8 mst during the same interval. During this period, coal receipts were also affected by fluctuations in nuclear and gas- and petroleum-fired electricity generation in the region.[27]

[25] M.F. McBride, "The Nuts and Bolts of Railroad Transportation Contracts," Proceedings of the Eighteenth Annual Eastern Mineral Law Institute, Columbus, OH, May 1997, Energy and Mineral Law Foundation, University of Kentucky, Mineral Law Center. (Lexington, 1997), p. 4 of 9

[26] In this case, the CTRDB data do not tell the whole story. For total domestic coal shipments to the region, those to CTRDB investor-owned utilities declined by 6.6 mst between 1988 and 1997 while those on the broader-based Form FERC-423 database increased by 2.2 mst (Table 2; see Appendix A for comparison of FERC-423 and FERC-580/CTRDB)

[27] Energy Information Administration, *Electric Power Annual 1996 and 1998, Volume I* (Washington, DC, August 1997 and 1999), Table 1C.

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Table 15. Middle Atlantic Demand Region – Selected Statistics for Contract Coal Shipments by Rail to Electric Utilities, 1988, 1993, and 1997*

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (Million Short Tons)				
Low-Sulfur Coal	1.5	1.3	0.5	-64.5
Medium-Sulfur A Coal	2.7	0.2	4.3	60.1
Medium-Sulfur B Coal	6.5	7.4	6.2	-3.7
High-Sulfur Coal	2.9	4.5	4.9	65.6
All Coal	13.6	13.4	15.9	17.2
Average Distance Shipped (Miles)	306.7	257.6	337.1	9.9
Average Transportation Rate per Million Btu (1996 Cents)	66.5	42.2	44.6	-32.9
Average Transportation Cost as a Percentage of Delivered Price	32.3	28.5	32.0	-0.9
Average Transportation Rate per Ton-Mile (Mills in 1996 Dollars)	40.3	38.9	34.3	-14.9

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

The near absence of change in average distances for coal shipments to the Middle Atlantic means that Northern Appalachia remained the major source of coal in this region. Even with this continuation of the status quo in coal origin/destination pairings, electric utilities in the region received a 14.9 percent reduction in real-dollar coal transportation rail rates per ton-mile (CTRDB 2000).[28] Since neither distances nor Btu content of the coal supplied changed appreciably (because it still originated primarily in Northern Appalachia), the decline in the transportation rate per million Btu confirms therefore that real dollar average rail rates did go down. The fact that the cost of coal rail transportation, as a percentage of delivered price, barely changed at all—a 0.9 percent decline—is consistent with minemouth coal prices decreasing at essentially the same rate as the contract rail transportation per ton of coal (Table 15).

East North Central Demand Region
(Ohio, Indiana, Illinois, Wisconsin, and Michigan)

The East North Central demand region is ideally situated for access to coal, which it receives from each of the five major supply regions. Traditionally it takes coal from both Northern and Central Appalachia, to the east and south, and from the Illinois Basin, more than 4/5 of which lies within the East North Central demand region. By 1979, the earliest year in the CTRDB, the Powder River Basin (PRB) already ranked third among regions supplying coal to the East North Central, surpassing nearby Central Appalachia. Also as early as 1979, coal from the Rockies supply region (Colorado and Utah) had made inroads into the East North Central, offering low- and medium-sulfur A bituminous coals for boilers that need a higher Btu coal (often to blend with medium- or high-sulfur coals) or that require bituminous coal combustion characteristics. By 1997, the PRB had become the leading supply region for the East North Central, accounting for 50.9 percent of coal delivered (CTRDB 2000).

This region lies at the crossroads of the major eastern and western U.S. railroad systems and of an important north-south rail system linking Canada and the Gulf of Mexico. The East North Central includes Mississippi and Ohio River crossings and transfer yards, as well as major rail hubs in Chicago and Cincinnati, and Great Lakes rail transfer facilities in Chicago-Gary, Toledo, Detroit, and Cleveland. Rail transport has long been the principal mode for coal shipments in this region, rising from 52.7 percent of total contract coal tonnage in 1979, to 55.4

[28] 14.9 percent is the reduction in weighted average rates for coal shipped by rail from Northern Appalachia and Central Appalachia, for which rates are withheld in Table 14.

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percent in 1988, and 63.0 percent in 1997. Multimode transport—mostly combinations of rail and barge—ranks second in coal shipments, followed by barge-only—18.2 and 10.4 percent of coal shipments, respectively, in 1997 (CTRDB 2000).

Multimode arrangements traditionally have worked well for those East North Central power plants located on waterways, receiving coal from rail-served Northern Appalachia, Central Appalachia, and Illinois Basin coal producers. Conversely, certain coal producers in those three regions have coal preparation and loadout facilities at river docks along the Monongahela, Ohio, Kanawha, and Green Rivers that are used to barge coal to efficient transloading facilities for East North Central rail deliveries. More recently, several state-of-the-art rail and rail-water transfer and blending facilities have been developed in the region. They act as both transfer and staging locations for incoming PRB coal (by rail) for blending and/or reclassifying to appropriate train sets for power plant requirements. Ultimate delivery may be by rail, river barge, or Great Lakes colliers.

While the East North Central region is situated well for coal deliveries from any of the major supply regions, coal distribution from only the PRB and the Rockies regions increased during the CAAA90 study period (Table 4). Deliveries from other, closer-by regions either declined or remained roughly unchanged, thereby becoming a smaller percentage of total deliveries, which grew by 44.4 mst. The net increase in shipments of all coal was more than explained by PRB coal, whose receipts grew by 46.1 mst, or 127 percent. The largest reduction was in the region's own Illinois Basin coal, whose receipts fell of by 5.6 mst, or 9.0 percent. As a result, the receipts of low-sulfur coal increased by 235 percent and the average shipping distance grew from 452 to 829 miles (Table 16).

Changes in coal sources and the attendant increases in average shipping distances were to be expected considering that this demand region produces 44.2 percent of the sulfur dioxide emissions mandated for reduction in Phase I.[29] Nonetheless, transportation rates were not increased in mills per ton-mile nor in terms of cents per

Table 16. East North Central Demand Region - Selected Statistics for Contract Coal Shipments by Rail to Electric Utilities, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (Million Short Tons)				
Low-Sulfur Coal	18.0	23.9	60.4	235.4
Medium-Sulfur A Coal	14.7	9.4	14.3	-2.9
Medium-Sulfur B Coal	2.0	5.9	3.6	81.1
High-Sulfur Coal	28.1	17.4	14.2	-49.5
All Coal	62.9	56.5	92.5	47.2
Average Distance Shipped (Miles)	452.4	638.8	829.4	83.3
Average Transportation Rate per Million Btu (1996 Cents)	57.6	50.9	50.3	-12.6
Average Transportation Cost as a Percentage of Delivered Price	25.4	30.6	37.0	45.7
Average Transportation Rate per Ton-Mile (Mills in 1996 Dollars)	26.5	15.6	11.3	-57.4

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

[29] Energy Information Administration, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities* (DOE/EIA-0582(97)) (Washington, DC, March 1997), Figure 1, p. 2

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million Btu (Table 16). The cost per million Btu is important considering the lower Btu value[30] of PRB coal. Even with a significant decline in Btu per ton of coal, average rail rates declined apace and resulted in a net decrease of 12.6 percent in the average rate per million Btu. The average cost of transportation as a percentage of coal delivered price went up as expected—after all, typical reported mine prices of PRB coal fell from more than $20 per ton to less than $5 per ton during this period.

For example, in 1988, the CTRDB indicates that East North Central utilities agreed to hefty mine prices for PRB coal: prices ranged broadly, from less than $6 per ton to more than $30 per ton. The average price was $14.55 per ton. By 1997, East North Central utilities paid prices ranging from less than $4 per ton to more than $15. The average price had fallen to only $5.89 per ton. The higher prices in the range were holdovers from the few old contracts which had not yet expired. During the same period, the average rail rates from the PRB to the East North Central fell from $21.69 per ton to $12.38 (CTRDB 2000). All rates and prices quoted are in nominal dollars.

West North Central Demand Region
(Missouri, Iowa, Minnesota, Kansas, Nebraska, South Dakota, and North Dakota)

This region includes the upper Mississippi River, the navigable portions of the Missouri River, and coal-related rail facilities at St. Louis, Kansas City, and Nebraska (Alliance, North Platte, and Omaha—PRB-related train yards). More than any other major demand region, the West North Central relies on rail for coal deliveries. River transport, including coal, is a major business in St. Louis and in several upper Mississippi towns, but almost all coal loaded on barges is destined for customers in other demand regions. In 1979, 84.4 percent of coal transported to customers in this demand region was by rail. Rail deliveries remained at this level over the next decade, accounting for 83.7 percent of coal deliveries in 1988, prior to any CAAA90 impacts. By 1997, that portion had risen to 95.9 percent as truck and minemouth deliveries nearly ceased due to the closing of small, local mines in Missouri, Kansas, and Iowa that produced extremely high-sulfur coal (CTRDB 2000).

Most coal transported to the West North Central region traditionally came from the nearby Illinois Basin for the region's eastern States such as Missouri and Iowa or from North Dakota, the PRB, or Kansas, depending on proximity. By 1979, responding to existing coal emission limits, CTRDB utilities in the region were already receiving 26.0 mst of low-sulfur contract coal—53.3 percent of their total—from the PRB. By 1988, PRB contract coal receipts at those utilities were 42.8 mst, and in 1997 the figure reached 66.1 mst, or 90.8 percent of their contract coal receipts (CTRDB 2000).

Fundamental changes took place between 1988 and 1997 in coal supply arrangements for West North Central electric utilities. For utilities included in the CTRDB (Table 17):

- Contract rail shipments of coal increased by 61.8 percent
- Low-sulfur contract rail shipments of coal doubled
- Use of medium-sulfur A coal was relatively unchanged, but because of the surge in low-sulfur coal shipments, market share fell from 23.0 percent to 13.8 percent of total receipts.
- Coal transportation rates declined by 31.1 percent, in cents per million Btu, and by 36.8 percent, in mills per ton-mile.
- Still, the transportation portion of delivered coal prices rose by 9.0 percent because average distances increased and minemouth coal prices declined faster than shipping costs (CTRDB 2000).

Table 17 documents that in 1997, 69.8 mst of contract coal were shipped to electric utilities included in the CTRDB, versus Table 1, with 120.2 mst shipped to utilities reporting on FERC Form 423. The shipments in Table 1 are greater because Form 423 data include spot market coal purchases, coal shipped by modes other than rail, and utilities that are not required to report on FERC Form 580 (Form 580 is the primary basis for the CTRDB). Consequently, the net increases in coal shipments on the two tables differ: 26.7 mst, or 61.8 percent, on Table 17 but only 20.6 mst, or 17.2 percent, for the broader, larger database for Table 1. Clearly, coal shipped by rail increased more actively at the CTRDB utilities than did the total coal shipments at the Form-423 utilities.

[30] As more PRB coals ranging from 8,300 to 9,700 Btu per pound replaced high-sulfur bituminous coals ranging from 10,800 to 13,400 Btu per pound, the average heat content of coal delivered to the East North Central region went from 11,127 to 10,588 Btu per pound between 1988 and 1997. Source: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1988*, and *1997*, (DOE/EIA-0191(88) and (97)) (Washington, DC, August 1989 and May 1998), Tables 48 and 4, respectively.

Table 17. West North Central Demand Region - Selected Statistics for Contract Coal Shipments by Rail to Electric Utilities, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	29.5	48.2	59.2	100.8
Medium-Sulfur A Coal	9.9	7.3	9.6	-3.2
Medium-Sulfur B Coal	2.4	2.2	0.0	-100.0
High-Sulfur Coal	1.3	2.5	1.0	-28.0
All Coal	43.1	60.1	69.8	61.8
Average Distance Shipped (miles)	732.9	797.5	805.7	9.9
Average Transportation Rate per Million Btu (1996 cents)	80.8	64.5	55.7	-31.1
Average Transportation Cost as a Percentage of Delivered Price	56.7	58.3	61.8	9.0
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	19.0	14.0	12.0	-36.8

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

Although the 26.7 mst increase at the CTRDB utilities is covered in monthly Form 423 data, it cannot readily be cross-referenced because of different reporting requirements. It can be inferred, however, that rail shipments increased much more slowly among non-CTRDB utilities. In this case, it is not self-evident why the trends in the two databases differ. The degrees to which trends are expressed in each database result from the confluence of diverse coal supply contract conditions, delivery mode requirements, timed purchase decisions, and environmental compliance strategies.

What is clear from both databases is that receipts of low-sulfur coal in the West North Central region increased appreciably. The 29.7 mst increase in contract coal shipments (Table 17) of low-sulfur coal by rail accounts for the entire increase in coal shipments as well as a 3.0 mst decrease in medium- and high-sulfur shipments. Further, the increase in low-sulfur coal shipments of all types to West North Central electric utilities cut average sulfur content of coal receipts nearly in half (Table 2). These improvements in the potential for coal used in the region to form acid emissions were accomplished without increases in the average rail transportation rates for low-sulfur coal. In fact the rates fell for all coal types shipped to the East North Central region (Tables 13 and 17). The only increase—in transportation cost as a percentage of delivered price—was a consequence of average mine prices of coal declining more than average rail transportation rates.

South Atlantic Demand Region

(Delaware to Florida, including Maryland, Virginia, District of Columbia, West Virginia, North Carolina, South Carolina, and Georgia)

The South Atlantic coal demand region covers a disparate area, physically, economically, and in terms of coal consumption patterns. A core of Atlantic Seaboard States from Delaware to South Carolina continues to rely on the traditional coal sources in Central and Northern Appalachia supply regions that are located in the mountain uplands just to the west. Not conforming to the patterns of the core States are West Virginia, Florida, and, to a lesser extent, Georgia.

Historically, the South Atlantic region has received coal mostly by rail—67.4 percent as of 1979, 54.7 percent in 1988, rising to 70.6 percent in 1997 for contract deliveries (CTRDB 2000). The core States have no direct river transportation options and they consistently comprise most of the rail shipments referred to above. High- to medium-sulfur Illinois Basin coal is logistically and practically uncompetitive in these core States. Low-sulfur Powder River Basin (PRB) coals are logistically impractical and do not measure up on a Btu basis to the relatively nearby low-sulfur Central Appalachian coals.

West Virginia breaks with the core States primarily in its mix of transportation modes. Having barge access both for coal deliveries and for coal mines along the

Kanawha, Big Sandy, and Ohio Rivers, West Virginia coal transportation historically includes 15 to 25 percent barge and rail/barge shipments, as well as opportunities for truck, minemouth, and conveyor transport. Several utilities in Florida also receive coal by barge or multimode, including barge-only, rail-to-barge, barge-to-rail, and rail-to-barge-to-rail. Further, although no Georgia Power generating plants are situated on navigable rivers, some use barge transportation for initial transport legs of Illinois Basin and Central Appalachian coal. Throughout the period of study, utilities in Florida purchased Illinois Basin coal, which some blend with very low-sulfur imported coals. The appearance of PRB coal in 1997 (Table 13) is entirely based on Georgia Power purchases and shipments to Plant Scherer—nearly 2,000 miles by train (CTRDB 2000).

The South Atlantic region depends heavily on coal. It is second only to the East North Central region in total coal receipts and coal receipts at electric utility generators (Table 1). In 1993, coal tonnages shipped to the South Atlantic region had turned down slightly from their 1988 levels as coal demand by electric generators fluctuated during the early 1990's. By 1997, however, demand for coal was increasing again (Tables 1 and 18). For contract shipments to utilities, the demand for low-sulfur coal more than doubled from 1988 to 1997 (Table 18).

Virtually all low-sulfur coal shipped to the South Atlantic region was from Central Appalachia, with the following exceptions[31]:

- 5-7 mst of PRB coal shipped by train to Georgia Power's Plant Scherer[32] each year from 1994 to 1997
- Smaller amounts of PRB coal, generally less than 1 million tons, shipped to utilities in Florida[33] by train and by barge
- PRB coal test burns during the mid-1990's in Georgia and North Carolina

Most of the demand in this region, however, was for medium-sulfur A coal, coming primarily from Central Appalachia and Northern Appalachia (CTRDB 2000). Because of the proximity of the core States of the South Atlantic demand region to those supply regions, average shipping distances were moderate: 565 miles in 1997

Table 18. South Atlantic Demand Region - Selected Statistics for Contract Coal Shipments by Rail to Electric Utilities, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	8.4	8.0	19.8	135.9
Medium-Sulfur A Coal	33.4	31.6	47.5	42.4
Medium-Sulfur B Coal	6.8	4.7	1.3	-81.4
High-Sulfur Coal	6.4	0.3	1.2	-81.6
All Coal	55.0	44.6	69.8	26.9
Average Distance Shipped (miles)	347.3	415.2	565.0	62.7
Average Transportation Rate per Million Btu (1996 cents)	54.6	48.2	47.9	-12.3
Average Transportation Cost as a Percentage of Delivered Price	24.9	26.8	30.3	21.7
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	38.8	29.5	20.0	-48.5

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

[31] Based on FERC Form 423 data.

[32] Data on shipments to Plant Scherer are not in the CTRDB with the exception of 1997, for which limited data were derived from Surface Transportation Board Annual Waybill Statistics. The Waybill Statistics apply only to rail cargos.

[33] Transportation rates for coal shipments to Florida could not be derived because data for barge portions of the routings are not available.

(Table 18). For comparison, midwestern demand regions more dependent on PRB coal had average distances of 829 miles for the East North Central and 806 miles for the West North Central (Tables 16 and 17). Still, the average distance for South Atlantic region contract coal receipts grew significantly—from 347 miles in 1988 to 565 miles by 1997.

The growth in coal shipping distances was caused by changing to new suppliers, primarily within the same supply regions. That resulted in South Atlantic utilities contracting with coal suppliers who were, on average, several counties farther away than higher-sulfur coal suppliers used in 1988. High-sulfur and medium-sulfur B contract coal suppliers, for example, lost 10.7 mst in volume during that period, while low-sulfur and medium-sulfur A coal sources shipped 25.5 mst more (including coal for increased demand). The largest loss in coal volume from a single supply region was in the Illinois Basin, where volumes shipped declined from 12.4 to 4.4 mst (CTRDB 2000), owing to smaller contract purchases of Illinois Basin coal for Georgia Power Company plants. The absence of some of these high-sulfur and medium-sulfur A routings, usually of 600 to 700 miles, actually offset the effects of losses of 4.6 mst of relatively close-by coal supplies in Northern Appalachia and Southern Appalachia (CTRDB 2000).

In the face of a 62.7 percent increase in transport distances, the average rate per million Btu decreased by 12.3 percent and, not surprisingly, the rate per ton-mile decreased, in this case by 48.5 percent (Table 18). As shown in Table 13, the major decrease in straight dollar-per-ton rail tariffs was for coal shipped from the low-sulfur and medium-sulfur A Central Appalachia region. Both Northern Appalachia and Central Appalachia distances also increased, which pushed down the rates per ton-mile (Table 14). Indications are that, overall, contract coal transport rates to the South Atlantic region did not increase in the face of rising demand.

East South Central Demand Region
(Mississippi, Alabama, Tennessee, and Kentucky)

The rail system in this region is mature and pervasive, and is the leading mode for coal transportation. Nashville, Birmingham, Memphis, and Louisville are important rail hubs, and rail/river transloading docks are located at Memphis, Louisville, and along the lower Ohio River and its tributaries.

Volumes of rail coal shipments in the East South Central are followed by substantial shipments on its extensive waterways (see Table 5 in Chapter 2). On a percentage as well as gross tonnage basis, there is more coal shipped to this region by river than to any other. The region is drained by the lower Mississippi River, more than half the length of the Ohio River, five major navigable tributaries to the Ohio (the Big Sandy, Kentucky, Green, Cumberland, and Tennessee Rivers) in Kentucky, Tennessee, and Alabama, the Tennessee-Tombigbee and Black Warrior waterway system in Alabama and Mississippi, and the lower Chatahoochee River serving Alabama (and Georgia). Further, this region connects with waterborne shipping along the Gulf Coast via the Intracoastal Waterway and the Ports of Biloxi, Mobile, and (a few miles distant) New Orleans—transport options used for outbound coal shipments primarily.

The leading traditional coal supply region has been the demand region itself—including the mines of Alabama and Tennessee in the Southern Appalachia supply region and of Kentucky's two coalfields, in the Central Appalachia and Illinois Basin supply regions. Kentucky, Alabama, and Tennessee, in that order, receive nearly all the coal used at electric utilities in the region. Mississippi was the destination for only 6.5 percent of the coal in 1988 and 5.9 percent by 1997.[34]

The contract coal shipments shown in Table 19 indicate a 67.2 percent increase in volumes shipped by rail during the study period and a tripling of the volume of low-sulfur coal in those shipments. The increases, however, are in part an expression of database limitations and of coincidence. The coincidence is that there are no data for Rockies and PRB region coals in two of the criterion years shown in Table 18—1988 and 1993. Prior to 1988, however, millions of tons of Rockies-origin coal had been shipped by rail to Mississippi via contracts that expired at the end of 1986. Further, rail shipments of millions of tons of contract coals from both supply regions actually resumed in 1995, but did not show up in 1993 (see text box on page 34).

The 12.6 mst increase in low-sulfur contract coal from 1988 to 1997 in Table 19 is based largely on increased rail distribution from two regions: the PRB (+8.9 mst) and the Rockies (+2.2 mst). The remaining 1.5 mst of increase in low-sulfur rail shipment was contract coal from the Central and Southern Appalachia supply regions. In the East South Central region, however, the

[34] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants* (DOE/EIA-0191) (Washington, DC, 1989, 1998), Table 26 and Table 22, respectively.

Table 19. East South Central Demand Region - Selected Statistics for Contract Coal Shipments by Rail to Electric Utilities, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	4.0	4.6	16.6	317.4
Medium-Sulfur A Coal	6.7	10.8	9.4	40.4
Medium-Sulfur B Coal	1.8	0.4	2.3	28.2
High-Sulfur Coal	8.3	6.8	6.4	-22.8
All Coal	20.7	22.6	34.7	67.2
Average Distance Shipped (miles)	191.7	211.3	593.3	209.5
Average Transportation Rate per Million Btu (1996 cents)	26.2	23.4	40.6	55.1
Average Transportation Cost as a Percentage of Delivered Price	14.9	16.3	28.4	90.6
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	34.2	27.6	14.2	-58.5

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

must be considered. All coal from the PRB and Rockies regions was low-sulfur and all was shipped entirely by rail, but coal shipments from Central and Southern Appalachia were shipped substantially by other modes.

For example, East South Central contract shipments of all coal types originating in Southern Appalachia (i.e., from Tennessee and northern Alabama) in 1997 amounted to 16.0 mst, of which 9.0 mst, or 56.2 percent were shipped by barge and multimode (generally barge plus rail and/or truck). In Central Appalachia, 14.4 mst of contract coal was originated, of which 4.7 mst, or 32.3 percent, traveled by barge, multimode, or entirely by truck. For the East South Central demand region overall, barge shipping alone accounted for 27.3 percent of all coal movements.

The rail transportation rates per million Btu increased for the East South Central region from 1988 to 1997. This is the only region where that happened. There are several reasons, related to the location of the region, its coal supply patterns during the study period, and the significant effects of barge delivery.

First, because of its location, rail hauls from Southern and Central Appalachia and the Illinois Basin are relatively short. On a dollar-per-ton basis these are the lowest rates of any demand region (Table 13), but the short haul distances result in characteristically higher rates on a mills-per-ton-mile basis, rates similar to those of midwestern demand regions (Table 14). Second, none of the high dollar-per-ton rates associated with the long hauls from the Rockies and PRB regions figured in 1998 and 1993, due to coincidental timing and lack of data from the Tennessee Valley Authority for those years (see text box). Third, barge and barge-multimode delivery is used for much of the Southern and Central Appalachian and Illinois Basin coal because, where barge is available, it is usually the most economical mode. The large influx of coal under western rail delivery rates in 1997 added coal with high rates per ton and low Btu values. This differed from rail data typical of prior years, which had low rates per ton and high Btu values.

Thus, the large increase in average distance shipped, rate per million Btu, and transportation cost as a percentage of delivered price for contract coal are exaggerated by the infusion of sporadically available data for PRB and Rockies coal. Likewise, the 58.5 percent fall in rail transportation rates per ton-mile reflect the availability of some data in 1997 for PRB coal shipped 1,200 to 1,400 miles and Rockies region coal shipped 1,400 to 1,600 miles. In conclusion, the downward trend in rail rates in this region is masked by changes in the mix of available rate data between 1988 and 1997. The

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Case Study - Differences in Databases and Reporting Criteria

Starting in the late 1970's, through 1986, Mississippi Power Company's Victor J. Daniel plant received as much as 1 million tons per year of Colorado and Utah bituminous coal from the Rockies region (CTRDB 2000). During much of the period of this study, however, the only coal transported to the East South Central region, which includes Mississippi, from low-sulfur origins in the West were test-burn sized shipments (a few hundred thousand tons). They went to several Tennessee Valley Authority (TVA) plants in Kentucky and Tennessee and, starting again in 1991, to Mississippi Power, from the PRB. By 1994 Mississippi Power and TVA were both receiving sizable shipments of western coals again, from both the Rockies and PRB. Because of the break in western-coal supply contracts, there were no Mississippi Power data on the CTRDB for Rockies or PRB purchases in 1988. Further, as Mississippi Power's 1991-1993 test burns were short-term spot purchases, they were not reported on Form 580 and are not in the CTRDB.

Because TVA is a Federal facility and does not report fuels information on FERC Form 580, only a minor portion of TVA data, regardless of the year, is in the CTRDB. Those data that are on file result from confidential waybill queries performed by the STB, covering principally the data years since EIA's *Interim Report on Coal Transportation*, that is, 1994 through 1997. The waybill queries provided primarily distance and shipping rates for calculated shipment tonnages. Not all coal shipments in all years, however, could be derived from STB waybill records. Tracing of waybills is complicated by TVA's use of central transshipment facilities and barge shipments for a part of some shipments, and by the unavoidable commingling of both spot and contract shipments, and of shipments to other customers or transloading facilities in the same destination counties as some power plants (the STB Waybill Sample does not collect information on individual supply contracts).

Table 13 (page 24) indicates that no western coal contract shipments to the East South Central region by rail were recorded in the CTRDB in 1988 or 1993. The shipments on file for 1997 (tonnages had to be withheld) amounted to an abrupt surge from the Rockies and from the PRB (CTRDB 2000). FERC Form 423 data for 1988 match the CTRDB, showing no western coal shipments of any kind to any utilities in its broad reporting base. In 1986, however, 1.3 mst of Rockies region coal receipts were recorded on Form 423 at the Victor J. Daniel plant, in the final year of the contracts that began in the 1970's.

In 1993, Table 4 indicates resumption of CTRDB shipments; the FERC Form 423 data recorded 1.2 mst from the PRB and Rockies regions—spot contracts for test burns. By 1995, the first year of Phase I of CAAA90, low-sulfur coal shipments to East South Central States had begun anew. FERC 423 receipts totaled 8.4 mst with deliveries to all four States in the region. Only a fraction of this tonnage (at the Daniel plant) was reported on FERC Form 580. Excluded was other Rockies coal at the Daniel plant, apparently due to criteria in the contract, and 6.1 mst of Rockies and PRB coal receipts reported on Form 423 by the TVA.

1997 rates for the East South Central region compare well, however, with rates in similar regions. For example, the 1997 contract coal rates by rail compare well with rates in the South Atlantic demand region (Tables 19 and 18):

Average distance	593.3 versus 565.0
Average rate per million Btu	40.6 versus 47.9
Average rate per ton-mile	14.2 versus 20.0

Any difference in appearance between the rate trends in the two regions is due largely to the late influx of TVA data in the East South Central region.

West South Central Demand Region

(Texas, Louisiana, Arkansas, and Oklahoma)

The West South Central demand region has long been heavily reliant on its rail infrastructure for coal deliveries. Mainlines of the Union Pacific system (including the routes of the Southern Pacific, Missouri Pacific, and Chicago and Northwestern railroads) and several regional railroads terminate coal deliveries, pass coal trains through the region and through important freight terminals at Houston and Fort Worth. Routes from Utah and from Colorado and the Powder River Basin (PRB) handle coal bound for the region and for Mexico. During the study period, 91 to 95 percent of all contract coal shipments terminating in the region moved entirely by rail (CTRDB 2000).

Neither the major barge shipping routes of the Lower Mississippi River and the Gulf Intracoastal Waterway, nor the less used Arkansas River waterway, figure into any coal deliveries in the CTRDB. Millions of tons of domestic coal, however, do traverse the Lower Mississippi to the Port of New Orleans, bound for export markets, or via the Lower Mississippi and Gulf Intracoastal Waterway, bound for Florida utilities.

All contract coal in the CTRDB shipped by rail to the West South Central region originated in the PRB and Rockies. The Rockies portion made up only 1.5 to 1.8 mst—shipments from Colorado to Central Power and Light Company's Coleto Creek plan in Texas. All remaining rail coal reported in Table 20 originated in the PRB with the exception of a few thousand tons of Oklahoma coal shipped to an Oklahoma power plant in 1988 (CTRDB 2000).

Despite the dominance in the West South Central region of rail deliveries for contract coal in the CTRDB, about half of total coal receipts in Table 20 are unaccounted for. This underrepresentation occurs because, as of 1997, less than 29 percent of total coal receipts (by all transport modes) were reported on FERC Form-580.[35]

To ensure that coal transportation rates and patterns to the region would be more fully represented, EIA supplemented contract coal tonnages in the CTRDB using STB Waybill Sample statistics (see discussion in Appendix A). For 1997, waybill tonnages added to the CTRDB comprise another 22 percent of total coal receipts. Total East South Central coal receipts between 1988 and 1997 have increased steadily, but coal receipts documented in the CTRDB have increased only due to the addition of supplementary waybill data (Table 21). Receipts based on Form 580 declined by 6.2 mst. In other words, the total coal receipts have not declined but the number of power plants required to report on FERC Form 580 has declined (Appendix A) and, consequently, so have the tons of reported coal receipts.

Based on the adjusted data in the CTRDB, 100 percent of contract rail coal receipts were low-sulfur coal. Those receipts grew by 9.1 mst during the study period, or 16.5 percent. The average distance shipped changed very

Table 20. West South Central Demand Region – Selected Statistics for Contract Coal Shipments by Rail to Electric Utilities, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	55.2	59.5	64.3	16.5
Medium-Sulfur A Coal	0.0	0.0	0.0	--
Medium-Sulfur B Coal	0.0	0.0	0.0	--
High-Sulfur Coal	0.0	*	0.0	--
All Coal	55.2	59.5	64.3	16.5
Average Distance Shipped (miles)	1,340.8	1,323.3	1,309.8	-2.3
Average Transportation Rate per Million Btu (1996 cents)	137.2	104.4	89.4	-34.8
Average Transportation Cost as a Percentage of Delivered Price	62.3	58.2	66.6	6.9
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	17.0	13.7	11.7	-31.2

* = Data round to zero.

-- = Not applicable.

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

[35] "Total receipts" are equated to the receipts reported on FERC Form 423, which collects data on cost and quality of fuels received at steam-electric power generating units with a combined generator nameplate capacity of 50 megawatts or larger. As of 1997, Form 423 covered approximately 700 power plants operated by 230 utilities. Coal receipts reported on Form 423 were estimated to include more than 99 percent of coal received at all power plants. (Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plant* 1997, DOE/EIA-0191(97) (Washington, DC, May 1998), Tables; p. iii.

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Table 21. **West South Central Demand Region – Comparison of Total Domestic Coal Receipts on FERC Form 423 with FERC Form 580 Contract Coal Receipts and Supplementary Data on Receipts, by State, 1988, 1993, and 1997**
(Million Short Tons)

Year	West South Central Region				Texas		Arkansas		Oklahoma	Louisiana
	Total (Form 423)	CTRDB[a]	Form 580	Supplementary	Form 580	Supplement	Form 580	Supplement	Form 580	Form 580
1988	117.144	60.604	45.085	15.519	18.194	15.519	11.434	--	8.381	7.076
1993	130.849	62.648	41.978	20.670	14.188	20.670	9.692	--	10.817	7.281
1997	135.759	68.379	38.910	29.469	16.611	19.604	1.293	9.865	13.626	7.380

[a] Data in CTRDB equals sum of data reported on Form 580 and supplementary data. CTRDB tonnages are always less than Form 423 totals.
-- = Not applicable.
Sources: Energy Information Administration, Coal Transportation Rate Database; Federal Energy Regulatory Commission, Form 423.

little, declining by 2.3 percent, or 31 miles in average distance (Table 20). Average transportation cost as a percentage of delivered price rose by 7 percent as a result of declining coal prices that changed more greatly than declining rail transport rates.

The underrepresentation of West South Central region coal data in the CTRDB, based on FERC Form 580, was most serious for Texas. This single State accounted for 68 percent of the region's total coal receipts in 1997. As discussed in Appendix A, most Texas utilities are not required to file fuel-related information on FERC from Form 580. In 1997, 82 percent of Texas coal receipts, or 75.8 mst, were not captured by Form 580 reports. Supplementary data entered by EIA added 29.5 mst of the missing data, including transportation rates and shipping distances. (Minemouth prices, contract information, and other details are not attainable from waybill statistics.) The supplementary data brought CTRDB coverage in Texas to 39 percent of total State coal receipts. In the rest of the region—the States of Arkansas, Louisiana, and Oklahoma—Form 580 reports typically covered about 70 percent of coal receipts. Form 580 coverage fell to 51 percent, however, in 1997, as Arkansas Power and Light's two plants became exempt (Table 21). Supplementary data in Arkansas brought adjusted CTRDB coverage to 74 percent (CTRDB 2000).

Although transportation rates are unknown for the coal receipts not covered in the CTRDB, the origins and destinations of the coal are known—from FERC Form 423—and the transportation modes are known for much of it. Referring to Table 21, the differences between coal receipts covered by Form 423 and those included in the CTRDB indicates the following coal receipts not covered in the CTRDB:

- 1988 56.540 mst
- 1993 68.201 mst
- 1997 67.380 mst

The patterns are similar each year, so 1997 can be used to illustrate. In that year, of the 67.380 mst of coal receipts not in the CTRDB, 64.842 can be further accounted for:

- 50.224 mst of Texas lignite received at minemouth electric power plants in Texas, all delivered by mine truck or conveyor
- 5.757 mst of PRB coal received in Louisiana, all by rail (based on plant offloading facilities)
- 5.197 mst of PRB coal received in Oklahoma, all by rail (based on plant offloading facilities)
- 0.094 mst of Oklahoma coal received in Oklahoma, by truck or rail, based on distance and offloading facilities
- the remaining difference, 6.150 mst, relates to differences in Form 423 and Form 580 coverage and survey criteria, tonnage discrepancies reported by the same plant, and the use of "expansion factors"[36] for STB waybill data; these differences cannot be readily reconciled.

[36] The Surface Transportation Board Annual Waybill Sample collects data from 1 percent to 5 percent of the waybills documenting Class I railroad freight shipments. The size of the sample is defined depending on the commodity and on the train size (number of cars). The reported tonnage of coal represented by sampled waybills between two points, therefore, is calculated from the sample data using statistically validated expansion factors.

In conclusion, the fact that 50.224 mst of lignite is not accounted for in Table 20 should be recognized. The lignite is a major component of contract coal receipts in the region, but the data would be of limited relevance to this report because there are no real transportation costs (small transfer costs are included in delivered price). Although no rate data are available for 10.954 mst of the PRB coal delivered to Louisiana and Oklahoma, 21.006 mst of rail deliveries and rate data are available and in the CTRDB. On the other hand, 3.570 mst of Louisiana lignite, received at the Dolet Hills electric power plant in Louisiana and included in the Form 580 and CTRDB data on Table 21, are not indicated in Table 20 as the lignite was delivered by truck and conveyor.

Mountain Demand Region
(Montana, Wyoming, Colorado, New Mexico, Arizona, Utah, Idaho, and Nevada)

The Mountain Region includes eight large western States, sparsely populated except for a few metropolitan areas such as Denver, Phoenix, Salt Lake City, Albuquerque, and Las Vegas. Still, with eight or more States' demand, the region generates a significant amount of electricity, and coal is the major energy source, fueling 69 percent of net generation by electric utilities in 1997.[37]

The Mountain Region wholly encompasses the PRB, Rockies, and Southwest supply regions, which originate all coal received by generating units in the Mountain region. As indicated in Chapter 2, the tonnage of coal received by electric utility generators during the study period varied between 117.1 mst in 1988 and 135.8 mst in 1997 (Table 1). Considering those figures, the tonnages of contract coal shipped by rail to those generators are deceptively low—accounting for only 17.0 mst in 1997 (Table 22). In large part, this is because a high proportion of the coal-burning generating units were not required to file FERC Form 580. Another factor is that the majority of the contract coal shipments reported on Form 580 and included in the CTRDB reached the power plants by modes other than rail. In 1997, for example, 21.9 mst arrived at power plants by mine truck, private mine- or utility-owned railroad, conveyor systems, or by the country's only operating coal slurry pipeline. All but the pipeline were short-haul or minemouth dispatches.

Even though land areas are great and population centers spread widely within this region, average coal transportation distances are relatively short because many power plants are sited near the coalfields or minemouths (Table 22). Average distances are similar to those of the much more compact Middle Atlantic demand region (Table 15). On average, the western railroads of this region offered competitive rates to their intra-regional customers, many of whom are the original power plants that placed long-term contracts with them and the now expanded low-sulfur coal mines. The rates per ton-mile decreased by 29.8 percent from 1988 to 1997. The decreases are not as great as those seen for longer hauls, such as to the East North Central or West North Central regions, with more than double the distances, because fixed loading and unloading costs and transfer fees make up a large portion of the Mountain region rates per ton-mile.

Average transportation cost as a percentage of delivered price varied slightly during the study period, but no discreet trends could be determined. Trends in the ratios of transportation cost to total delivered price would be more meaningful if either component of cost--mine prices within a specific supply region or transportation costs from a specific supply region—were consistent. In the Mountain region, however, the contract coal shipment data coverage varies widely during the study period. For example, the 18.2 mst in 1988 came 47 percent from the PRB and the remainder from the Rockies and the Southwest in roughly equal shares. In 1993, with 23.8 mst on file, the PRB and the Southwest region accounted for four-fifths of the contract coal delivered: 42 percent and 38 percent, respectively. By 1997, with only 17.0 mst on file, the Southwest originated the largest share, 39 percent, while the PRB originated 35 percent and the Rockies 25 percent (Table 22 and CTRDB 2000).

Although changes in cost as percentage of delivered price are relatively consistent in Table 22, they are internally erratic because each of the three supply regions has a different characteristic minemouth price for coal. Further, a wide variation occurs in coal sulfur levels (Table 22) and in individual routes' transportation costs versus delivered prices because of changes from year to year in the number of power plants in this region reporting on Form 580. This is a region where the reporting sample has consistently been small.

[37] Energy Information Administration, *Electric Power Annual, Volume I* (DOE/EIA-0348 (97)/1) (Washington, DC, July 1998), Tables 9 and 10. The term "eight or more" indicates that electric power plants in the region are affiliated with regional corporations, such as PacifiCorp, that transmit their generated power into networks which direct significant quantities outside the Mountain demand region to California, Oregon, and Washington, and Southern California Edison Company, which uses Arizona coal in its Mohave power plant in Nevada to generate electricity used in southern California.

Table 22. Mountain Demand Region – Selected Statistics for Contract Coal Shipments by Rail to Electric Utilities, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	13.8	17.0	15.4	11.5
Medium-Sulfur A Coal	4.4	6.8	1.6	-64.5
Medium-Sulfur B Coal	0.0	0.0	0.0	--
High-Sulfur Coal	0.0	0.0	0.0	--
All Coal	18.2	23.8	17.0	-6.9
Average Distance Shipped (miles)	353.3	295.7	309.9	-12.3
Average Transportation Rate per Million Btu (1996 cents)	58.6	38.6	36.9	-37.0
Average Transportation Cost as a Percentage of Delivered Price	31.7	28.2	28.0	-11.7
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	32.6	28.9	22.9	-29.8

-- = Not applicable.

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

Demand at Boilers Affected by Phase I of the Clean Air Act Amendments of 1990

Enough data are now available to assess the impact of Phase I of the CAAA90 on coal distribution. Table 23 summarizes, for all supply regions, the changes in sulfur content and in transportation rates for contract coal distributed by rail to boilers affected by Phase I compared with the changes for all boilers (affected and unaffected by Phase I). Typically, the changes for Phase I-affected boilers were measurably greater than for electric utility boilers overall. Phase I-affected boilers included the 263 listed units as well as (in 1997) 153 substitution and compensating (S&C) units.[38] The numbers of S&C units vary from year to year. In 1997, Phase I-affected units were located in six demand regions as follows:

- East North Central region: 195 units/ 112 listed
- East South Central region: 55 units/ 48 listed
- South Atlantic region: 72 units/ 44 listed
- Mid Atlantic region: 47 units/ 33 listed
- West North Central region: 43 units/ 24 listed
- New England region: 4 units/ 0 listed

United States Total: 416 units/263 listed

Between 1988 and 1997, receipts of low-sulfur coal shipped under contract by rail increased by 389 percent at Phase I-affected boilers. High-sulfur coal shipments declined by 50 percent (Table 23). The increase in low-sulfur coal receipts for all coal-fired utility boilers was only 82 percent (or, 64 percent for non-Phase I-affected boilers only). The large percentage increase for Phase I-affected boilers was less notable in terms of tonnage.

The increase in annual receipts of rail-shipped low-sulfur contract coal was 39.5 mst, while at the same time the increase for all boilers was 107.0 mst, leaving 67.5 mst shipped to non-Phase I-affected boilers (Table 23). The level of contract deliveries of low-sulfur coal had become relatively stable by 1997. Increases in deliveries to Phase I-affected boilers were presumably in response to Phase I, although a small percentage would result from increased generation. Increases in deliveries to non-Phase I-affected boilers, on the other hand, indicate the impact of coal-switching in general as an ongoing

[38] U.S. Environmental Protection Agency, 1997 Compliance Report, Acid Rain Program, Office of Air and Radiation (EPA-430-R-98-012) "Table B-1. Table 1 Units Designating Substitution and Compensating Units - 1997," (Washington DC, August 1998). In the context of this report, "Phase I-affected" boilers is used to refer to the 263 original "Table 1" boilers, listed by name in the CAAA90, along with 153 substitution units and compensating units listed in 1997 whose emissions were allowed by the EPA to substitute for some of the emissions associated with Table 1 units. Not included were seven "opt-in" units that had no emissions-reducing relationship with the Table 1 units.

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Table 23. Changes in Rail-Shipped Contract Coal Transportation at Phase I-Affected Boilers Compared to All Boilers, 1988, 1993 and 1997

Transportation Element	Phase I-Affected Boilers	All Boilers
Low Sulfur Receipts (million short tons)		
1988	10.2	130.6
1993	30.8	163.3
1997	49.7	237.6
Percent Change 1988 to 1997	**388.8**	**81.9**
High Sulfur Coal receipts (million short tons)		
1988	35.1	47.7
1993	23.3	31.9
1997	17.6	27.6
Percent Change 1988 to 1997	**-50.0**	**-42.3**
Average Shipping Distance (miles)		
1988	290.3	640.2
1993	490.1	715.5
1997	607.3	793.5
Percent Change 1988 to 1997	**109.1**	**23.9**
Average Transportation Rate per Ton (1996 dollars)		
1988	9.28	14.56
1993	9.08	11.92
1997	9.03	10.81
Percent Change 1988 to 1997	**-2.7**	**-25.8**
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)		
1988	30.3	23.2
1993	18.1	16.9
1997	14.6	13.6
Percent Change 1988 to 1997	**-51.7**	**-41.4**

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration: Coal Transportation Rate Database.

response to CAAA90, as well as growth in coal-fired generating demand. Many operators had increased or renewed existing low-sulfur coal contracts to meet extant emission requirements and had extended operational plans in view of the eventual implementation of Phase II requirements in January 2000.

During the 10 years from 1988 to 1997 average shipping distance grew by 109 percent for Phase I-affected boilers, compared with only 24 percent for all boilers. The difference supports the fact that affected boilers switched from nearby high-sulfur Northern Appalachia and Illinois Basin coals to much more distant coals (primarily) in the PRB and Rockies. The increase in average distance shipped for all coal was smaller because many of the unaffected boilers already had been receiving coal from the PRB and Rockies. The average rail transportation rate per ton-mile fell by a greater percentage for Phase I-affected boilers because the rate per ton-mile is lower for the longer shipments from western mines, compared to the relatively short hauls from eastern and midwestern coalfields (Table 23).

The average rail transportation rate per ton, however, fell by only 3 percent for Phase I-affected boilers, versus 26 percent for all boilers (Table 23). The difference is due to the greater average increase in shipping distance for the Phase I-affected boilers, which rapidly switched to more distant, low-sulfur coal suppliers during that period. Longer shipping distances resulted in greater net transportation costs for this group of customers, and little benefit from the generally declining rates.

Supply Regions - Contract Coal Transportation by Rail

This section examines changes from 1988 through 1997 in tonnage, sulfur content, and transportation rates for electric utility contract coal shipped by rail from each of the major coal supply regions (Figure 3, Chapter 2).

Northern Appalachia
(Pennsylvania, Ohio, Maryland, and northern West Virginia)

Northern Appalachia coal deposits consist primarily of medium- to high-sulfur coal. Between 1988 and 1993, as the demand for high-sulfur coal declined in preparation for Phase I of the CAAA90, the region's rail shipments of high-sulfur contract coal to electric utilities fell by 51 percent, causing a 28-percent decline in Northern Appalachia total rail shipments of contract coal. High-sulfur coal shipments regained about one-fourth of the decline, however, once Phase I adjustments were in place, and total rail shipments netted no significant change from 1993 to 1997 (Table 24).

In 1997, the average distance of these rail movements was 355 miles, 56 percent farther than in 1988. Nevertheless, the average transportation rate per ton declined

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Table 24. Northern Appalachia Supply Region – Selected Statistics for Utility Coal Shipments by Rail, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	0.4	0.5	0.5	4.9
Medium-Sulfur A Coal	8.9	5.2	9.2	3.3
Medium-Sulfur B Coal	13.3	13.6	7.7	-41.7
High-Sulfur Coal	13.2	6.5	8.3	-37.3
All Coal	35.8	25.8	25.7	-28.3
Average Distance Shipped (miles)	228.1	273.6	354.6	55.5
Average Transportation Rate per Ton (1996 dollars)	11.75	10.11	11.13	-5.3
Average Transportation Cost as a Percentage of Delivered Price	22.8	26.6	31.2	36.8
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	52.1	36.5	32.2	-38.2

• Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

by 5 percent. The average rate per ton-mile fell by 38 percent over the same period, a decline comparable to that from the Powder River Basin (PRB). This downturn may have been due to a substantial reduction in high-cost (per ton-mile) short rail movements, as railroads abandoned unprofitable short lines.[39] Another possible reason is economic pressure on railroads to reduce rates in order to moderate the decline in the shipments of high-sulfur coal from the region.

Transportation cost accounted for 31 percent of the average delivered price for contract coal shipped from Northern Appalachia by rail in 1997. Despite the decline in the average transportation cost, this was a higher proportion of the delivered price than in 1988 because minemouth prices for Northern Appalachia's high-sulfur coal dropped faster than did rail rates over the period.

Central Appalachia
(Virginia, eastern Kentucky, and southern West Virginia)

Central Appalachia—particularly southern West Virginia and eastern Kentucky—is the primary source of low-sulfur and compliance coals in the eastern United States. These coal reserves are much closer than PRB compliance coals to the major coal-burning utilities of the Midwest and Southeast. However, Central Appalachian minemouth prices are substantially higher, largely because mining costs are much higher for Central Appalachian coals than for PRB and other western coals, and partly because the coal's higher Btu content, low sulfur, and other properties traditionally made it valuable for metallurgical processes and for export. Central Appalachia saw a steady upward trend in rail-shipped contract coal distribution between 1988 and 1997 (Table 25). Total contact coal rail tonnage increased by 62 percent during the study period, or 29 mst. Based on total receipts (Table 4 in Chapter 1), the larger declines included coal shipped to utilities in the East North Central and East South Central regions—areas that were contended for by western coal suppliers, taking advantage of expanded track capacity, transfer facilities, and rail-to-barge options. The important increases from Central Appalachia were to utilities in the South Atlantic and Middle Atlantic regions, to which for the most part shipping of western coals is not practical or economic. The above changes in coal destinations resulted in a slight decrease in the average distance the coal was shipped (Table 25).

Changes in the cost of shipping this coal were more significant. Both the average rate per ton and the average rate per ton-mile fell by more than 30 percent

[39] Generally, the rate per ton varies directly with distance and the rate per ton-mile varies inversely with distance.

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Table 25. Central Appalachia Supply Region – Selected Statistics for Utility Coal Shipments by Rail, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1993
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	10.8	13.6	19.7	82.3
Medium-Sulfur Coal A	35.5	41.2	54.3	53.0
Medium-Sulfur B Coal	*	0.4	2.4	NM
High-Sulfur Coal	0.9	0.0	0.0	-100.0
All Coal	47.3	55.2	76.5	61.6
Average Distance Shipped (miles)	431.6	436.2	418.9	-2.9
Average Transportation Rate per Ton (1996 dollars)	15.03	12.04	9.92	-34.0
Average Transportation Cost as a Percentage of Delivered Price	26.3	26.8	26.8	1.9
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	33.8	27.4	23.6	-30.2

* = Data round to zero.

NM = Not meaningful.

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

during the study period. However, as minemouth coal prices fell faster than the average transportation rate per ton, transportation cost accounted for a slightly larger share of the delivered price in 1997 than in 1988.

Illinois Basin

(Illinois, Indiana, and Western Kentucky)

Two related facts underlie the statistics for the Illinois Basin: (1) most coal reserves of the Illinois Basin are high in sulfur content and (2) Phase I of CAAA90 affected more total nameplate capacity at generating units in the adjoining East North Central supply region than in any other. High-sulfur coal accounted for 58 percent of the contract coal shipped from the Illinois Basin by rail in 1997 (Table 24). This share was down from 85 percent in 1988, as shipments of high-sulfur coal fell by 42 percent during the study period. Illinois Basin contract coal shipments to utilities in the East North Central demand region fell by 29 percent, as many of those utilities turned increasingly to PRB low-sulfur coal (CTRDB 2000). Total Illinois Basin coal shipments to the East North Central region, including receipts not in the CTRDB, for all shipment modes, went down by 9 percent (Table 4 in Chapter 2).

Rail hauls of coal from Illinois Basin mines are far shorter than shipments of coal from any other supply regions. From 1988 to 1993, the average distance contract coal from the Illinois Basin was shipped on railroads declined from 106 to 96 miles, as customers, especially customers more distant from the Illinois Basin began testing and contracting for lower-sulfur coal supplies. By 1997, however, the average distance had rebounded to 122 miles. Although coal tonnages shipped from the Illinois Basin during the study period declined in all demand regions, shipments to the East South Central region changed very little and thus became a larger portion of the total shipments. Part of the reason for the increase in mileage by 1997 was that the Tennessee Valley Authority (TVA) shipped more of its Illinois Basin rail tonnage to power plants more distant from the mines. For example, in 1988 the average rail distance the TVA shipped Illinois Basin coal was 67.5 miles. By 1993 that average was up to 122.5 miles, and by 1997 had reached 168.5 miles (CTRDB 2000).

The average rail transportation rate per ton of Illinois Basin coal fell by 17 percent between 1988 and 1997 (Table 26). Because of the relatively short hauls, the average transportation rate per ton was far lower than in the other coal supply regions. For the same reason, the average rate per ton-mile was higher than in any other supply region and mirrored fluctuations in average distance shipped.

Table 26. Illinois Basin Supply Region - Selected Statistics for Utility Coal Shipments by Rail, 1988, 1993 and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	0.2	0.2	1.4	765.9
Medium-Sulfur A Coal	3.7	1.4	8.8	138.6
Medium-Sulfur B Coal	2.0	4.4	3.3	64.4
High-Sulfur Coal	32.5	25.2	18.9	-41.7
All Coal	38.3	31.2	32.4	-15.4
Average Distance Shipped (miles)	106.0	96.2	121.8	14.9
Average Transportation Rate per Ton (1996 dollars)	4.86	3.93	4.04	-16.9
Average Transportation Cost as a Percentage of Delivered Price	11.9	11.5	15.4	29.4
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	44.9	41.5	33.1	-26.3

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

Largely because of the short average lengths of rail haul, transportation cost accounted for a relatively small percentage of the average delivered price of the contract coal shipments from mines in the region. While still low, average transportation cost as a percentage of delivered price rose slightly from 1988, when it made up 12 percent of delivered price, to 1997 when it made up 15 percent (Table 26).

Powder River Basin
(Wyoming and Montana)

The Powder River Basin (PRB)[40] is the Nation's premier source of low-sulfur coal. Abundant coal deposits in the PRB are extremely thick and relatively close to the surface, making them inexpensive to mine by surface methods. Therefore, minemouth prices are low relative to prices of other coals. This advantage is offset to some extent by the relatively low Btu content of PRB coals.

Coal from the southern portion of the basin, in Wyoming, has the lowest sulfur content. With some notable exceptions, coal from the northern end of the basin, in Montana, generally has slightly more sulfur and less heat content. Also, the transportation infrastructure is less developed in the northern end than in the southern part of the Basin.

The Powder River Basin leads all regions in the amount of coal distributed domestically, accounting for nearly 318 mst, or 32 percent of the total in 1997.[41] It also accounted for 272 mst, or 44 percent of all coal shipped by rail to domestic consumers.[42] More than 85 percent of PRB coal was moved by rail to its final destination.

The region stands out in many respects. Besides producing the greatest overall tonnage and the greatest low-sulfur coal tonnage, it has the longest average shipping distance, the highest ratio of transportation cost to delivered price (on a per ton basis), and the lowest average transportation rate per ton-mile.

PRB coal producers and the railroads serving the region benefitted greatly from the increased demand for

[40] The Powder River Basin technically is a geologic sedimentary basin which is contained almost entirely in seven counties—four in northeastern Wyoming and three in southeastern Montana. There have been several active coal mines in those two States that were outside the PRB during the study period, but they produced only 1 percent of the States' production. Because of the minor difference, and because of incomplete data as to originating coalfield for some information sources, all coal shipped from Wyoming and Montana is treated as "Powder River Basin" in this report.

[41] Energy Information Administration, *Coal Industry Annual 1997* (DOE/EIA-0584(97)) (Washington, DC, December 1998), Table 59

[42] Energy Information Administration, *Coal Distribution, January-December 1997* (DOE/EIA-0125(97/4Q)) (Washington, DC, open-file report), Table 17.

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compliance coal that resulted from clean air legislation. Between 1988 and 1997, contract rail shipments in the CTRDB of low-sulfur PRB coal grew by 89 percent, to 193.1 mst (Table 27). Low-sulfur coal represented 94 percent of the contract coal shipped from the PRB in 1997—up from 87 percent in 1988—and medium-sulfur A coal accounted for the remainder.

As PRB coal shipments have extended as far east as utilities in Florida and Georgia, the average shipping distance for contract rail movements rose by nearly 6 percent between 1988 and 1993. The increase occurred because of large increases in coal tonnages shipped to more distant power plants in demand regions such as the East South Central, East North Central, and South Atlantic, along with continuing large shipments, and some increases, to Texas and other West South Central utilities. In 1988, about 34 percent of the contract coal shipped by rail from the Powder River Basin had gone to utilities in the West North Central region, rising to 37 percent in 1993 and, despite further increases in tonnage, declining to 32 percent in 1997 (Table 28). Although the West North Central region was the leading recipient of PRB by 1997, surpassing the 63.3 mst received in the West South Central region, the greatest increase in tonnage was by the East North Central demand region. The distances to this region are 685 miles farther from the PRB, on average, than the distances to the West North Central region (CTRDB 2000).

Reflecting the long average shipping distance, the average transportation rate per ton for contract coal rail shipments from the Powder River Basin is quite high, while the average rate per ton-mile is lower than in any other region. Transportation cost accounted for nearly 62 percent of the delivered price of coal from the Powder River Basin in 1997, slightly lower than in 1988 (Table 27). Between 1988 and 1997, the average rate per ton fell by 35 percent and the average rate per ton-mile fell by 39 percent. This decline in transportation rates reflects the technological improvements and efficiency gains of western railroads in the face of earlier excess coal transportation capacity, excess coal production capacity, and the intense competition possible after passage of the Staggers Act. Excess coal production and transportation capacity resulted from the large investments that were made after the oil crises of the 1970's and the failure of coal demand to grow as rapidly as had been expected. By 1994, however, growth in shipments led to congestion problems in the southern Powder River Basin. Substantial capacity investments have been and are still being made in this and other areas.

Rockies Region
(Colorado and Utah)

While most utilities affected by the CAAA90 appear to be turning to the PRB for low-sulfur coal supplies, others have secured supplies from the Rockies—specifically,

Table 27. Powder River Basin Supply Region - Selected Statistics for Utility Coal Shipments by Rail, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	102.3	131.5	193.1	88.8
Medium-Sulfur A Coal	15.3	12.3	11.4	-25.6
Medium-Sulfur B Coal	0.0	0.0	0.0	--
High-Sulfur Coal	0.0	0.0	0.0	--
All Coal	117.6	143.8	204.5	73.9
Average Distance Shipped (miles)	1,077.2	1,096.7	1,138.0	5.6
Average Transportation Rate per Ton (1996 dollars)	19.38	14.40	12.56	-35.2
Average Transportation Cost as a Percentage of Delivered Price	59.5	58.7	61.5	3.4
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	18.0	13.4	11.0	-38.9

-- = Not applicable.

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

Table 28. Powder River Basin Supply Region – Changes in Rail Distribution of Contract Coal to Major Demand Regions, 1988, 1993, and 1997
(Million Short Tons)

	1988	1993	1997
Total PRB Rail Shipments	117.6	143.8	205.1
PRB Rail Shipment to Major Demand Regions			
West North Central	39.4	53.6	65.3
East North Central	15.8	22.4	54.7
West South Central	53.7	57.7	63.3
PRB Rail Shipment to Other Demand Regions	8.7	10.1	21.8

Note: Total Powder River Basin rail shipments in this table include some tonnages not shown in other supply region and demand region tables. It includes tonnages that were missing rate, Btu, and/or sulfur data and could not be included in tables that involved those parameters in calculating the values.
Source: Energy Information Administration, Coal Transportation Rate Database.

from the Uinta geological region of northern Colorado and Utah and the Yampa region of northwest Colorado. Utilities in the Midwest and the Southeast contracted for supplies of this bituminous coal, which has a higher Btu content than Powder River Basin subbituminous coal and can be burned more readily in existing boilers that were designed for bituminous coal.

Only 7 mst tons of contract coal were shipped from the Rockies by rail in 1988, increasing to 11 mst by 1997 (Table 29). Most of the Rockies coal is delivered within the Mountain demand region. As noted in the section on the Mountain demand region, however, many of its utilities are not required to file FERC Form 580 and disclose transportation details. Table 4 in Chapter 2 documents that more than 4 times the amount in Table 26 was actually received at utilities.

Much of the coal shipped to distant markets from this region used multimode (combined rail/barge) movements. All of the rail-shipped coal was low-sulfur coal, and most of it (4 to 5 mst during the study period) was hauled to utilities in the Mountain demand region, which includes Colorado and Utah. One and one half to 2 mst were rail-shipped to the West South Central region in during the study. Although shipments to the East North Central region increased from nearly none to 1.5 mst during the study (Table 4), none of the deliveries were reported on Form 580. They most likely were rail-transported and may have included some rail/barge multimode. Likewise, the nearly 5 mst noted in Table 4 as received in 1997 in the East South Central region is a significant increase that is not reported via Form 580. Using waybill data, EIA was able to document 2.2 mst that year shipped by train to the TVA, but could not get complete information on the rest—some of which was multimode.

Rail shipments of low-sulfur coal from the Rockies to the Midwest were expected to increase more significantly than they actually have so far. Innovative transport arrangements, such as low backhaul rates[43] offered by the Southern Pacific (now part of the Union Pacific) in the mid-1990's, have had only limited effectiveness at building new business. Concerns among many utilities over the potential for rail traffic congestion in the PRB were assuaged largely as Union Pacific and Burlington Northern added extra trackage in bottleneck areas, new sidings, enlarged rail yards and transfer facilities, and new locomotives and control systems during 1996 through 1998.

Highly productive longwall mining methods are used in the Rockies. The extent to which the region's markets can expand depends on how rapidly and for how long productivity can continue to increase. Productivity gains lower production costs, which in turn allows the coal to be sold at lower prices.[44] Ultimately, the bituminous coal of the Rockies must compete with the low mine prices of the PRB even though its coal is higher in Btu value. Many utilities have found satisfactory operational modes to use to profit from the abundant lower-Btu PRB coals, and the Rockies coals must compete with them as a delivered product. Since the shipping costs to the

[43] The Southern Pacific, for example, hauled metallurgical coal and iron ore to Geneva Steel in Provo, Utah, and offered low rates for hauling coal on the eastbound return of the trains.
[44] For a description, history, and economic analysis of longwall mining, see the Energy Information Administration report, *Longwall Mining*, DOE/EIA-TR-0588 (Washington, DC, March 1995).

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Table 29. Rockies Supply Region – Selected Statistics for Utility Coal Shipments by Rail, 1988, 1993, and 1997

Data Element	1988	1993	1997	Percent Change 1988 to 1997
Tonnage Shipped by Rail (million short tons)				
Low-Sulfur Coal	6.6	7.7	11.0	67.3
Medium-Sulfur A Coal	0.0	0.0	0.1	--
Medium-Sulfur B Coal	0.0	0.0	0.0	--
High-Sulfur Coal	0.0	0.0	0.0	--
All Coal	6.6	7.7	11.1	68.6
Average Distance Shipped (miles)	688.1	738.1	990.7	44.0
Average Transportation Rate per Ton (1996 dollars)	18.45	14.29	11.98	-35.1
Average Transportation Cost as a Percentage of Delivered Price	37.7	38.1	40.1	6.4
Average Transportation Rate per Ton-Mile (mills in 1996 dollars)	26.8	19.4	12.6	-53.0

-- = Not applicable.

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Totals may not equal sum of components because of independent rounding. • One mill equals 0.1 cent. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.

Source: Energy Information Administration, Coal Transportation Rate Database.

Midwest or Mid-South are similar from the Rockies or the PRB, further reductions in delivered prices would require either lower minemouth prices or lower, possibly volume-based, transportation rates.

Even though the average shipping distance for rail movements of contract coal from the Rockies increased by 44 percent between 1988 and 1997, the average transportation rate per ton declined by 35 percent. The average rate per ton-mile fell by 53 percent. Transportation cost accounted for 40 percent of the average delivered price in 1997 (Table 29).

Appendix A

Detailed Description of the Coal Transportation Rate Data Base

Appendix A

Detailed Description of the Coal Transportation Rate Data Base

Appendix A presents a detailed description of the Coal Transportation Rate Data Base (CTRDB), including its content and data sources, data reliability, data quality, relationship to other data systems and coverage, and data availability.

History and Database Description

The CTRDB is a comprehensive database that contains electric utility coal supply contract data and transportation-related data. The data for this system are originally collected by Federal Energy Regulatory Commission (FERC) on Form 580, "Interrogatory on Fuel and Energy Purchase Practices," to conduct reviews of utility fuel and energy purchase practices as mandated by the Public Utility Regulatory Policies Act of 1978 (Public Law 95-617), which amended Section 205 of the Federal Power Act of 1920. The survey is conducted every 2 years. It requires responses from all jurisdictional utilities that either operate at least one steam-electric generating station with a capacity of 50 megawatts or greater, or have an ownership interest in a jointly-owned steam-electric station with a capacity of 50 megawatts or greater. Jurisdictional utilities are facilities involved in the transmission of electric energy in interstate commerce and the sale of electric power at wholesale in interstate commerce.

The CTRDB was originally developed to provide information on coal supply contracts, contract tonnage, contract expiration date, and transportation rate by mode for an Energy Information Administration (EIA) model used to project coal supply and transportation. Starting in 1985, coal contract information for 1983 was obtained from FERC. In 1986, all contract and transportation information was collected from the FERC 580 survey responses for the years 1984 and 1985. In 1987, a need for an historical analysis of transportation rates arose. At that point, FERC provided EIA with historical coal contract information from the FERC Form 580 for the years 1979 through 1982.

The CTRDB currently contains data for 1979 through 1997 and is updated as new data are collected in the FERC Form 580 survey. The system contains approximately 925 records for each year for as many as 135 investor-owned utilities. Investor-owned electric utilities may be independently operated or part of a holding company. The utilities are usually operating companies that provide basic services for the generation, transmission, and distribution of electricity. Investor-owned electric utilities currently operate in all States except Nebraska.

The FERC is not empowered to collect Form 580 information from non-jurisdictional entities such as Federally owned electric utilities or publicly owned utilities including municipalities and cooperatives that do not engage in interstate transmission or generation of wholesale electric power. The Tennessee Valley Authority (TVA), the largest federally owned power producer, with coal receipts of 32.1 million tons in 1997 and electric utility plants operating in Alabama, Kentucky, and Tennessee, is not required to report on Form 580. Texas Utilities Electric Co., a large nonjurisdictional utility that is not required to report on Form 580, had coal receipts of 33.3 million tons in 1997. Publicly owned utilities not reporting on the FERC 580 are concentrated in Arizona, California, Nebraska, Oregon, and Washington. Utilities that do not use the Fuel Adjustment Clause do not have to report on Form 580. In the late 1990's fewer and fewer utilities were using the fuel adjustment clause and therefore fewer are reporting on Form 580.

Because FERC Form 580 and thus the CTRDB excludes a significant portion (57 percent in 1997) of the contract coal consumed at and transported to U.S. electric utilities, an effort was made to improve the coverage of the CTRDB and to provide a more comprehensive view of transportation rates. Supplementary data for the CTRBB came primarily from the Surface Transportation Board "Annual Waybill Sample" and from the FERC "Monthly Report of Cost and Quality of Fuels for Electric Plants,"

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Form 423, for utilities not covered by Form 580. The CTRDB was augmented by the inclusion of confidential data from Form 580 and with derived transportation rates that were computed from known mine price and delivered price data.

The records contained within the CTRDB are contract- and route-oriented. For each utility plant receiving coal under a specific contract, the CTRDB provides an origin-to-destination record for every route over which that plant's coal flows. A contract record within the CTRDB can be broken down into four subsets of data fields: contract accounting and specification information, plant information, route information, and transportation mode information. A utility company within the database can have several coal supply contracts; one coal supply contract can serve several plants; an individual plant can receive coal from several mines on the same contract; and an individual plant can be covered by several different contracts.

The contract accounting and specification information consists of:

- Contract code
- Utility company code
- Utility name
- Contract sign data
- Contract expiration data
- Contract modification date
- Annual base tonnage contracted
- Btu contracted
- Sulfur content contracted
- Ash content contracted
- Moisture content contracted
- Contract/supplier name
- Mine name
- Origin State code
- Origin State name
- Origin county code
- Bureau of Mines district code
- Type of contract.

The plant-related data consist of:

- Plant code
- Plant name
- Plant location by State code and name
- Actual volume of coal shipped to the plant during year under survey
- Minemouth price of coal shipped to plant
- Delivered price of coal shipped to plant
- Btu content of actual coal shipments
- Actual sulfur content of shipments
- Actual ash content of shipments
- Actual moisture content of shipments
- Number of boilers targeted by the Clean Air Act.

Route and transportation mode related data consist of:

- Route number
- Number of links
- Total line-haul distance for the route
- Transportation mode for each route link
- Line-haul distance for each link
- Transportation rate for each link
- Transfer fees for route transshipment points
- Transshipment point name
- Railroad or barge company name.

Coal prices and transportation rate data may be reported in cents per million Btu, dollars per ton, and dollars per million Btu. Coal shipments and base contracted tons are in short tons. Sulfur and ash contents are in percent by weight. Heat content is reported in Btu per pound.

Relationship to Other Data Systems and Coverage

Since the CTRDB is drawn from the FERC Form 580 system survey, its data consistency and coverage can be described in the context of Form 580 and its relationship to other data systems. The Form 580 survey population is a subpopulation within the survey population for Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Utilities." Form 580 covers jurisdictional public utilities while Form 423 covers all public utilities, i.e., investor-owned utilities, federally owned utilities, municipalities, and cooperatives. The Form 580 survey is conducted every 2 years, while the Form 423 survey is conducted monthly.

As of 1993, FERC Form 580 covered an average of 135 utilities and 259 plants per year, while FERC Form 423 covered approximately 235 utilities and 700 power plants. As of 1997, the Form 423 coverage was down to 222 utilities and 656 fossil fuel plants, of which 169 utilities and 403 plants had coal receipts. Further, Form 580 collects data for utility contract purchases only, whereas Form 423 collects data for both utility contract purchases and spot purchases. Spot purchases are purchase orders to obtain coal for a period of less than 1 year.

Although both surveys collect data on utility contract purchases of coal, more utilities report contract purchases on Form 423 than on Form 580, and thus, the coverage and the contract tonnage reported is higher than for Form 580. Contract tonnage was chosen as the variable to measure consistency of reporting for the two systems. In order to obtain a more comprehensive record of contract tonnage, the Form 580 contract tonnage was augmented with data derived from the Surface Transportation Board (STB) Carload Waybill Sample. Thus the contract tonnage in the CTRDB is the combination of Form 580 contract tonnage and STB Carload Waybill Sample derived contract tonnage. Table A1 shows the breakdown of Form 423 tonnage into contract and spot totals, CTRDB Coal tonnages by Form 580 and augmented data totals, and the CTRDB tonnage as a percentage of both the FERC 423 total tonnage and the FERC 423 contract tonnage. The total contract coal received at U.S. utilities was 721.5 million tons in 1997 according to Form 423. The 520.1 million tons of contract tonnage recorded by the CTRDB accounted for 72.1 percent of the Form 423 contract coal receipts or tonnage, as opposed to 309.7 million short tons reported by Form 580 alone, which would account for only 42.9 percent of the Form 423 contract tonnage total.

Survey population differences contribute to four sources of variations between FERC Form 580 and FERC Form 423 data series: (1) frame differences, (2) different reporting periods, (3) requirements based on electric generating station capacity (steam-electric generating station and peaking units with either 24 megawatts capacity or 50 megawatts capacity could have reported

Table A1. Comparison of FERC Form 423 and Coal Transportation Rate Database Coal Tonnages, 1979-1997
(Million Short Tons)

Year	FERC Form 423 Coal Tonnages			CTRDB Coal Tonnages by Source		CTRDB Augmented Coal Tonnages as a Percentage of FERC Form 423 Data	
	Total	Contract	Spot	Form 580 Only[a]	Augmented[b]	Total Tonnages	Contract Tonnages
1979	556.6	485.1	71.4	309.7	342.9	61.6	70.7
1980	594.3	525.6	68.7	335.0	373.3	62.8	71.0
1981	579.4	503.4	76.0	310.9	342.4	59.1	68.0
1982	601.4	543.8	57.6	343.9	373.0	62.0	68.6
1983	592.7	523.6	69.1	382.5	382.5	64.5	73.0
1984	684.1	584.8	99.3	462.2	462.2	67.6	79.0
1985	666.7	592.4	74.3	453.6	454.6	68.2	76.7
1986	687.0	601.0	86.0	424.8	424.8	61.8	70.7
1987	721.3	610.2	111.1	422.5	422.5	58.6	69.2
1988	727.8	627.8	100.0	436.8	474.0	65.1	75.5
1989	753.2	620.9	132.3	434.3	476.2	63.2	76.7
1990	786.6	648.6	138.0	447.2	497.2	63.2	76.7
1991	769.9	655.5	114.5	458.8	500.3	65.0	76.3
1992	776.0	649.5	126.5	441.7	481.2	62.0	74.1
1993	769.2	616.0	153.2	461.7	461.7	60.0	74.9
1994	831.9	646.7	185.2	472.9	563.9	67.8	87.2
1995	826.9	668.4	158.5	489.5	574.3	69.5	85.9
1996	862.7	700.1	162.6	369.6	475.9	55.2	68.0
1997	880.6	721.5	159.1	309.7	520.1	59.1	72.1

[a]Coal tonnages derived from qualified FERC Form 580 data entered in CTRDB.
[b]Coal tonnages based on qualified FERC Form 580 data augmented with data derived from the Surface Transportation Board Carload Waybill Sample.
Source: Federal Energy Regulatory Commission, FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," and FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Utilities."

on either survey, depending on the requirements at the time), and (4) data reporting procedures, data recording, and processing procedures for the two systems.

Data Reliability and Quality

The FERC manages all quality control issues, mandates the type of data collected, and handles nonresponses and respondent contact records for the FERC Form 580.

Quality assurance measures in the extraction of data from Form 580 responses are handled by the EIA. An effort is made to rectify coding errors, tabulation errors, keying errors, and problems of data interpretation. However, FERC 580 responses may contain estimates or averages of transportation rates for several shipments under one contract and estimates of volumes and distances of shipments, because the data are not collected primarily for input into the CTRDB.

The data are coded onto hard copy coding forms as reported by the respondents. The coded forms are then compared with the original responses to detect and correct transcription errors. Once a computer file has been created, the computer file is compared with the coded forms to detect and correct data entry errors.

An error detection and correction program is used to detect and correct errors that escape manual screening. This program consists of a set of ranges and range checks for all quantitative data fields within the database. The range values were established in coordination with FERC personnel. When the database is evaluated using this program, values that fall outside of pre-established ranges are identified for investigation. Internal inconsistencies are corrected using a program that compares values from year to year to detect outliers based on the series of values. This program also resolved problems of record redundancy. Table presentations are also examined for regional and national transportation data consistencies. Data record printouts are reviewed and outliers are eliminated where deemed necessary.

For a few specific demand regions, supply regions, and/or transportation modes, time series data vary considerably from one year to the next. In most cases, this appears to be due to the small number of records for which transportation rate data were available for that particular region or transportation mode. In those cases, fluctuations in tonnage or rates for one contract could have a substantial influence on the regional average. This situation occurred most frequently for shipments from the "Other Western Interior" region and for shipments by truck and "other" transportation modes (primarily conveyors). Although the averages based on this "thin" data are included in the tables of this report, they were not used for any of the analyses upon which the report's conclusions are based.

Data Availability

The CTRDB data are based on public use data from the FERC 580 for the years 1979 through 1987 and both public use and confidential data for 1988 through 1997. For the years 1979 through 1987, data that were not available due to confidentiality consisted of coal transportation rate and coal minemouth price. Also, some records did not have complete data. To minimize the influence of missing data on statistical calculations, records with missing data were excluded from certain calculations. Furthermore, an effort was made to increase the availability of data through derivation in two ways: (1) when two of the three cost data elements were available, the third one was derived from the available data; i.e., if minemouth price and delivered price were available, the transportation rate was derived by subtracting the minemouth price from the delivered price; and (2) certain FERC 580 confidential data were made available for the years 1988 through 1997 under an agreement between EIA and the FERC to display the confidential data only in an aggregated form.

The availability of data on coal transportation rate per ton, distance, and tonnage is important because these variables are used in the calculation of the average distance shipped, average transportation rate per ton, and average transportation rate per ton-mile. Tables A2, A3, and A4 show the number of records and tonnage contained in the CTRDB, the number of records and tonnage obtained from Form 580, the number of supplementary records and tonnage in addition to Form 580, and the number of records and tonnage for unqualified data. The data for Tables A2, A3, and A4 include all transportation modes, not just rail. The unqualified data for Table A2 are records that do not contain data for the distance shipped. The tonnage for these records are not included in the calculation for average distance. In 1997 there are 92 records that did not contain data for distance, as a result 41.5 million short tons of coal was disqualified from the average distance shipped calculation. The records on the three tables include data for all transportation modes, not just rail. Similarly, the unqualified data for Table A3 are the records that do not contain data for the

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Table A2. Data Elements Available for the Calculation of Average Distance Shipped, 1979-1997

Year	Total CTRDB		FERC 580		Supplementary		Unqualified Data	
	Records	Tonnage	Records	Tonnage	Records	Tonnage	Records	Tonnage
1979	930	342.9	615	249.0	69	31.3	246	62.6
1980	886	373.3	598	275.3	95	37.0	193	61.0
1981	871	342.4	620	268.1	90	31.0	161	43.3
1982	770	373.0	589	296.8	86	28.3	95	47.9
1983	736	382.5	612	309.0	0	0.0	124	73.4
1984	793	462.2	697	378.6	3	0.0	93	83.6
1985	791	454.6	679	376.9	12	1.0	100	76.8
1986	826	424.8	667	338.9	13	0.0	146	86.0
1987	816	422.5	691	336.8	3	0.0	122	85.7
1988	871	474.0	667	327.9	37	35.5	167	110.6
1989	883	476.2	680	330.7	38	39.3	165	106.3
1990	984	497.2	826	392.9	36	35.5	122	68.9
1991	968	500.3	826	403.4	34	40.3	108	56.6
1992	1,010	481.2	892	382.2	32	38.4	86	60.5
1993	992	461.7	880	355.8	32	41.4	80	64.4
1994	1,285	563.9	1,079	421.4	133	91.0	73	51.5
1995	1,196	574.3	1,012	440.0	107	84.8	77	49.6
1996	946	475.9	717	329.4	144	106.3	85	40.2
1997	957	520.1	710	343.6	155	135.0	92	41.5

Notes: *CTRDB* is EIA's Coal Transportation Rate Database. The CTRDB is based on data from *FERC Form 580* with *Supplementary* data from the Surface Transportation Board's Annual Waybill Sample and from the Federal Energy Regulatory Commission's Annual Files for Form 423. *Unqualified data* are CTRDB data based on incomplete Form 580 data (missing rates, distance, and /or coal quality) for which Supplementary data are not available.

Source: Federal Energy Regulatory Commission, FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," and Department of Transportation, Surface Transportation Board, "Annual Waybill Sample."

transportation rate per ton. In 1997 there are 67 records that do not contain transportation rate data and 55 million short tons are disqualified from the calculation of average transportation rate per ton mile.

Table A4 shows the data available for the calculation of the average transportation rate per ton-mile. The unqualified data for Table A4 takes into account records that are missing both distance data and transportation rate data. Since this is a combination of data from Table A2 and A3 there are more unqualified records (124) and tonnage (67.7 mst) disqualified for the calculation of the average transportation rate per ton-mile.

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Table A3. Data Elements Available for the Calculation of Average Transportation Rate per Ton, 1979-1997

Year	Total CTRDB		FERC 580		Supplementary		Unqualified Data	
	Records	Tonnage	Records	Tonnage	Records	Tonnage	Records	Tonnage
1979	930	342.9	710	245.8	71	30.7	149	66.3
1980	886	373.3	667	273.8	97	38.0	122	61.6
1981	871	342.4	660	253.0	93	31.5	118	57.8
1982	770	373.0	523	259.2	90	29.1	157	84.6
1983	736	382.5	570	290.5	0	0.0	166	92.0
1984	793	462.2	610	329.5	4	0.0	179	132.8
1985	791	454.6	602	323.2	21	1.0	168	130.5
1986	826	424.8	455	203.3	13	0.0	358	221.5
1987	816	422.5	464	205.8	3	0.0	349	216.7
1988	871	474.0	633	297.8	39	37.2	199	139.0
1989	883	476.2	646	298.0	39	41.9	198	136.3
1990	984	497.2	752	352.0	39	50.0	193	95.2
1991	968	500.3	740	359.6	36	41.5	192	99.2
1992	1,010	481.2	873	356.2	33	39.4	104	85.6
1993	992	461.7	858	337.5	34	41.8	100	82.3
1994	1,285	563.9	1,016	375.3	133	91.0	136	97.6
1995	1,196	574.3	954	392.7	107	84.8	135	96.8
1996	946	475.9	738	314.0	144	106.3	64	55.6
1997	957	520.1	735	330.1	155	135.0	67	55.0

Notes: *CTRDB* is EIA's Coal Transportation Rate Database. The CTRDB is based on data from *FERC Form 580* with *Supplementary* data from the Surface Transportation Board's Annual Waybill Sample and from the Federal Energy Regulatory Commission's Annual Files for Form 423. *Unqualified data* are CTRDB data based on incomplete Form 580 data (missing rates, distance, and /or coal quality) for which Supplementary data are not available.

Source: Federal Energy Regulatory Commission, FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," and Department of Transportation, Surface Transportation Board, "Annual Waybill Sample."

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Table A4. Data Elements Available for the Calculation of Average Transportation Rate per Ton-Mile, 1979-1997

Year	Total CTRDB		FERC 580		Supplementary		Unqualified Data	
	Records	Tonnage	Records	Tonnage	Records	Tonnage	Records	Tonnage
1979	930	342.9	565	225.7	68	29.4	297	87.8
1980	886	373.3	549	252.3	95	37.0	242	84.0
1981	871	342.4	574	241.5	90	31.0	207	69.9
1982	770	373.0	505	253.9	86	28.3	179	90.7
1983	736	382.5	517	260.9	0	0.0	219	121.5
1984	793	462.2	600	320.1	3	0.0	190	142.1
1985	791	454.6	593	318.3	12	1.0	186	135.3
1986	826	424.8	428	192.2	13	0.0	385	232.7
1987	816	422.5	435	193.0	3	0.0	378	229.6
1988	871	474.0	581	278.5	37	35.5	253	160.0
1989	883	476.2	596	281.3	37	39.3	250	155.7
1990	984	497.2	813	391.0	36	35.5	135	70.8
1991	968	500.3	695	345.0	34	40.3	239	115.0
1992	1,010	481.2	826	339.4	32	38.4	152	103.4
1993	992	461.7	818	322.1	32	41.4	142	98.2
1994	1,285	563.9	989	367.1	133	91.0	163	105.8
1995	1,196	574.3	927	385.4	107	84.8	162	104.1
1996	946	475.9	688	300.5	144	106.3	114	69.1
1997	957	520.1	678	317.4	155	135.0	124	67.7

Notes: *CTRDB* is EIA's Coal Transportation Rate Database. The CTRDB is based on data from *FERC Form 580* with *Supplementary* data from the Surface Transportation Board's Annual Waybill Sample and from the Federal Energy Regulatory Commission's Annual Files for Form 423. *Unqualified data* are CTRDB data based on incomplete Form 580 data (missing rates, distance, and /or coal quality) for which Supplementary data are not available.

Source: Federal Energy Regulatory Commission, FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," and Department of Transportation, Surface Transportation Board, "Annual Waybill Sample."

Appendix B

Characteristics of Coal Supply Contracts Reported on the FERC Form 580

Appendix B

Characteristics of Coal Supply Contracts Reported on the FERC Form 580

Appendix B presents background information on the characteristics of coal supply contracts as they are reported on the Federal Energy Regulatory Commission (FERC) Form 580, "Interrogatory on Fuel and Energy Purchase Practices." Table B1 presents detailed information on individual coal supply contracts effective in 1997, organized by electric utility company, power plant, and contract expiration date.

Coal supply contracts are binding agreements, usually lasting 1 year or longer, between utility companies and coal producers and/or brokers. Coal supply contracts contain provisions that are binding upon the utility company and the vendor for the duration of the contract agreement. Typically, such provisions address:

1. Term or length of contract, possibly with contract extension provisions

2. Minimum quantity to be purchased

3. Source(s) of the coal and/or its quality characteristics

4. Base rate in terms of dollars per ton as of the effective date of the contract

5. Rate adjustment, which is used to adjust rates for inflation or deflation. Rate adjustment may be annual or quarterly and may be partial or total. It may be based on various indices, such as the gross domestic product (GDP) implicit price deflator. Adjustment may be aggregate or component-by-component, and may include adjustment for productivity change.

Other items addressed by the contract agreement are price, base quantity, quality specifications, quality incentives, quality penalties, supplier name, fuel production location, contract sign date, expiration date, and renewal and renegotiation options.

Coal supply contract information, including transportation- and shipment-related data, is listed in Table B1 for each plant receiving coal under contract reported on the FERC 580. Table B1 contains contracts, effective in 1997, that are to expire in 1997 and beyond.

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DOE024-1093

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Alabama Power Co												
1997	Barry	Consolidation Coal	Rend Lake	IL	Barge	30	0.871	0.75	12049	N/A	N/A	34.20
	E C Gaston	Pittsburg & Midway	North River	AL	Train	154	0.306	1.83	12098	N/A	N/A	32.98
	Miller	Drummond Co Inc	Various	AL	Barge	34	0.019	0.64	12036	N/A	N/A	45.69
1998	Barry	Addington Resources	Vandalia Resources	WV	Barge	1,413	0.084	0.82	12297	N/A	N/A	37.41
	E C Gaston	Heartland Res Inc	Various	WV	Train	750	0.823	0.75	12119	N/A	N/A	38.03
	Greene County	Addington Resources	Vandalia Resources	WV	Barge	1,215	0.624	0.97	12331	N/A	N/A	33.24
	Miller	AMAX Coal West, Inc.	Belle Ayr	WY	Train	1,450	5.192	0.25	8591	N/A	N/A	20.68
1999	E C Gaston	Jim Walter Res Inc	Blue Creek, Mary Lee	AL	Train	99	1.432	0.67	12435	N/A	N/A	54.76
	E C Gaston	Oak Mountian Mining	Boone No. 1	AL	Train	35	0.688	0.67	12670	N/A	N/A	37.43
	E C Gaston	Pittsburg & Midway	North River	AL	Train	154	0.387	2.19	12051	N/A	N/A	30.79
	Greene County	Alabama Coal Coop	Various	AL	Barge	193	0.111	2.08	11901	N/A	N/A	39.89
	Greene County	Costain Coal Inc	Baker	KY	Barge	905	0.434	2.17	12160	N/A	N/A	30.11
	Miller	Jim Walter Res Inc	Blue Creek, Mary Lee	AL	Train	50	2.557	0.60	12445	N/A	N/A	54.88
	Miller	U.S. Steel Mining	Oak Grove	AL	Barge	34	0.172	0.46	13580	N/A	N/A	37.06
2000	Barry	Drummond Co Inc	Shoal Creek, Cedrum	AL	Barge	324	0.346	0.75	12102	N/A	N/A	50.21
2001	Barry	Drummond Co Inc	Shoal Creek	AL	Barge	342	1.745	0.72	12231	N/A	N/A	51.32
	Miller	Drummond Co Inc	Shoal Creek	AL	Barge	34	1.618	0.69	12390	N/A	N/A	50.37
Appalachian Power Co												
1999	Clinch River	Ambrose Branch Coal	Various	VA	Train	31	0.010	0.97	13125	N/A	N/A	34.72
	Clinch River	Cane Patch Coal Sale	Cane Patch,Matt	VA	Train	40	0.124	0.91	12851	N/A	N/A	33.72
	Glen Lyn	Ambrose Branch Coal	Various	VA	Train	125	0.115	0.93	13100	N/A	N/A	38.44
	Glen Lyn	Wellmore Coal Corp	Various	VA	Train	114	0.167	0.88	12336	N/A	N/A	35.37
	John E Amos	Cyprus Amax Coal	Various	WV	Barge	45	0.012	1.00	11783	N/A	N/A	24.69
	John E Amos	Mountain View Coal	Various	WV	Train	68	1.083	0.87	13037	N/A	N/A	57.08
	John E Amos	SPE Corporation	Various	WV	Train	58	0.026	0.70	12237	N/A	N/A	48.65
	Mountaineer (1301)	SPE Corporation	Various	WV	Multimode	120	0.388	0.67	12228	N/A	N/A	54.64
2000	John E Amos	Arch Coal Sales	Ruffner, Wylo	WV	Train	109	0.512	0.63	12437	N/A	N/A	32.60
	Mountaineer (1301)	Arch Coal Sales	Ruffner, Wylo	WV	Multimode	171	0.396	0.63	12328	N/A	N/A	35.98
	Mountaineer (1301)	Pen Coal Corp	Various	WV	Barge	81	0.844	0.63	12018	N/A	N/A	34.26
2001	Clinch River	Coastal Coal Sales	Various	VA	Train	24	0.066	0.83	12879	N/A	N/A	32.51
	Clinch River	Pittston Coal Sales	Various	VA	Train	9	1.309	0.73	12340	N/A	N/A	33.67
	Glen Lyn	Coastal Coal Sales	Various	VA	Train	119	0.051	0.86	12740	N/A	N/A	36.42
	John E Amos	Burco Res Corp	Various	WV	Train	62	0.118	0.64	12595	N/A	N/A	33.49
	Mountaineer (1301)	Burco Res Corp	Various	WV	Multimode	124	0.533	0.63	12547	N/A	N/A	37.97
2002	Clinch River	Delta Coals Inc	Various	VA	Train	40	0.088	0.91	12929	N/A	N/A	31.86
	Glen Lyn	Delta Coals Inc	Various	VA	Train	134	0.126	0.93	12975	N/A	N/A	36.43
	John E Amos	Pittston Coal Sales	Various	WV	Train	108	0.844	0.67	12116	N/A	N/A	31.44
	Mountaineer (1301)	Pittston Coal Sales	Various	WV	Multimode	170	0.141	0.66	12101	N/A	N/A	36.10
2003	John E Amos	Ashland Coal Inc	Job 7 21	WV	Train	48	1.191	0.74	11984	N/A	N/A	37.22
	John E Amos	Ashland Coal Inc	Various	WV	Train	48	0.921	0.86	12078	N/A	N/A	31.37

See notes at end of table

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DOE024-1094

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Appalachian Power Co (continued)												
2005	John E Amos	Orion Resources Inc	Various	WV	Barge	29	0.106	0.85	12329	N/A	N/A	29.15
2005	Kanawha River	Orion Resources Inc	Various	WV	Barge	9	0.403	0.82	12223	N/A	N/A	28.56
2008	John E Amos	Pittston Coal Sales	Various	WV	Barge	62	0.029	1.20	12462	N/A	N/A	43.84
2008	Kanawha River	Pittston Coal Sales	Various	WV	Barge	11	0.437	0.73	12552	N/A	N/A	44.17
Arizona Public Service co												
2000	Cholla	Pittsburg & Midway	McKinley	NM	Train	116	1.929	0.44	9926	N/A	N/A	33.88
N/A	Cholla	Pittsburg & Midway	McKinley	NM	Train	116	1.068	0.44	9681	N/A	N/A	21.66
Black Hills Power & Light co												
2000	Ben French	Wyodak Resources Dev	Wyodak, Fort Union	WY	Truck	135	0.125	0.33	8098	7.02	8.44	17.11
2000	Osage	Wyodak Resources Dev	Wyodak, Fort Union	WY	Truck	65	0.238	0.70	7903	8.45	3.68	12.13
Cardinal Operating												
2000	Cardinal	Windsor Coal	Windsor	WV	Barge	4	0.462	3.75	12377	N/A	N/A	105.58
2001	Cardinal	Marietta Coal	Marietta	OH	Barge	18	0.514	2.83	11694	N/A	N/A	26.31
2004	Cardinal	Sands Hill	Various	OH	Barge	189	0.128	2.47	11059	N/A	N/A	28.09
Carolina Power & Light co												
1996	Ashville	Pyxis Coal Sales Co	Paramont	VA	Train	202	0.051	0.98	12505	N/A	N/A	32.36
1997	Cape Fear	International & Dome	McKoy Elkhorn	KY	Train	490	0.007	0.94	12454	N/A	N/A	35.83
1997	Lee	International & Dome	McKoy Elkhorn	KY	Train	613	0.015	1.26	12157	N/A	N/A	35.67
1997	Robinson	Knott Floyd Land Co	Elkhorn 3, Hazard 7	KY	Train	511	0.201	1.37	11565	N/A	N/A	34.31
1997	Sutton	International & Dome	McKoy Elkhorn	KY	Train	565	0.061	1.10	12009	N/A	N/A	35.32
1997	Weatherspoon	International & Dome	McKoy Elkhorn	KY	Train	533	0.015	1.28	12464	N/A	N/A	37.31
1998	Ashville	Sunny Ridge Entrpse	Ridgetop/Job 10	KY	Train	293	0.143	1.08	12648	N/A	N/A	35.08
1998	Ashville	Trail Energy, Inc	CT&T Coal	KY	Truck	151	0.189	1.13	12581	N/A	N/A	34.07
1998	Cape Fear	Arch Coal Sales Co	New Ridge No. 1	WV	Train	412	0.014	0.75	12363	N/A	N/A	36.84
1998	Cape Fear	Sunny Ridge Entrpse	Ridgetop/Job 10	KY	Train	370	0.010	0.84	12744	N/A	N/A	32.42
1998	Mayo	Arch Coal Sales Co	New Ridge No. 1	WV	Train	328	0.010	0.72	12589	N/A	N/A	35.10
1998	Roxboro	Arch Coal Sales Co	New Ridge No. 1	WV	Train	328	0.889	0.83	12140	N/A	N/A	35.23
1998	Roxboro	Arch Coal Sales Co	New Ridge No. 1	WV	Train	328	0.005	0.73	12526	N/A	N/A	34.85
1999	Roxboro	Pavler Coal Sales Co	Beech Fork	KY	Train	412	0.262	1.21	12158	N/A	N/A	33.71
2004	Cape Fear	SMC Mining Company	Various	WV	Train	385	0.426	0.97	12267	N/A	N/A	38.33
2004	Lee	SMC Mining Company	Various	WV	Train	500	0.424	0.92	12297	N/A	N/A	38.81
2004	Roxboro	SMC Mining Company	Various	WV	Train	335	0.645	0.93	12362	N/A	N/A	36.44
2004	Sutton	Franklin Coal Sales	Bates, Bluegrass	KY	Train	643	0.339	1.07	12707	N/A	N/A	55.55
2004	Weatherspoon	Franklin Coal Sales	Bates, Bluegrass	KY	Train	529	0.048	1.17	12411	N/A	N/A	56.20
2006	Ashville	Eastern Associated	Harris	WV	Train	327	0.147	0.87	12456	N/A	N/A	43.34
2006	Cape Fear	Eastern Associated	Harris	WV	Train	680	0.022	0.92	12825	N/A	N/A	43.51
2006	Lee	Eastern Associated	Harris	WV	Train	648	0.052	0.94	12813	N/A	N/A	43.39
2006	Mayo	Mountaineer Coal Dev	Various	WV	Train	335	1.839	0.64	11960	N/A	N/A	45.30
2006	Roxboro	Eastern Associated	Harris	WV	Train	404	1.149	0.89	12648	N/A	N/A	37.95
2006	Roxboro	Mountaineer Coal Dev	Various	WV	Train	335	0.901	0.65	11899	N/A	N/A	45.25

See notes at end of table

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DOE024-1095

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Carolina Power & Light Co (continued)												
2006	Sutton	Eastern Associated	Harris	WV	Train	731	0.114	0.95	12941	N/A	N/A	44.96
2006	Weatherspoon	Eastern Associated	Harris	WV	Train	683	0.095	0.93	12823	N/A	N/A	45.38
Central Hudson Gas & Elec												
1998	Danskammer	Intergrity Coal Sale	Sidney, High Power	KY	Train	–	0.262	0.62	13211	N/A	N/A	46.09
Central Illinois Light co												
1997	E D Edwards	Exxon Coal & Mineral	Monterey	IL	Train	136	0.563	1.16	10292	N/A	N/A	24.97
1997	E D Edwards	Franklin Coal Sales	Turris	IL	Truck	48	0.347	3.12	10481	N/A	N/A	24.02
2010	Duck Creek	Freeman United Coal	Crown II	IL	Train	106	0.857	3.60	10710	N/A	N/A	44.81
2010	E D Edwards	Freeman United Coal	Crown II	IL	Train	117	0.072	3.60	10706	N/A	N/A	50.03
2010	E D Edwards	Freeman United Coal	Crown II	IL	Truck	117	0.072	3.60	10706	N/A	N/A	46.63
Central Illinois Pub Serv co												
1997	Hutsonville	Amax Coal Sales	Minnehaha	IN	Truck	28	0.008	2.42	10822	N/A	N/A	28.14
1997	Meredosia	Black Beauty Coal Co	Cedar Creek	IL	Truck	28	0.294	2.57	11485	N/A	N/A	39.09
1997	Newton	Kindill Coal Sales	Kindill	IN	Train	80	0.192	0.48	10820	N/A	N/A	28.00
1997	Newton	Solar Sources Co	Monroe City	IN	Train	125	0.370	0.52	11214	N/A	N/A	30.88
2005	Newton	Black Beauty Coal Co	Air Quality	IN	Train	101	0.837	0.56	11072	N/A	N/A	35.40
2010	Coffeen	Exxon Coal USA Inc	No 1	IL	Train	71	1.990	1.18	10283	N/A	N/A	38.02
2010	Meredosia	Exxon Coal USA Inc	No 1	IL	Truck	90	0.149	1.15	10217	N/A	N/A	35.06
Central Louisiana Elec Co Inc												
2007	Rodemacher	Kerr-McGee Coal Corp	Jacob's Ranch	WY	Train	1,596	1.843	0.49	8706	N/A	N/A	27.32
Central Operating co												
1999	Sporn	Anker Energy Corp	Various	WV	Barge	338	0.340	1.65	12185	N/A	N/A	26.25
1999	Sporn	Camelot Coal Co	Mays Run, Crafts Run	WV	Barge	336	0.260	1.76	12011	N/A	N/A	25.55
1999	Sporn	Cyprus Amax Coal	Various	WV	Barge	109	0.366	1.45	12065	N/A	N/A	26.73
2003	Sporn	Ashland Coal Co	Job 7 21	WV	Multimode	110	0.006	0.73	12356	N/A	N/A	43.40
2003	Sporn	Ashland Coal Inc	Various	WV	Multimode	110	0.004	0.85	11836	N/A	N/A	35.75
2006	Sporn	Pittston Coal Sales	Various	WV	Barge	114	0.643	1.10	12464	N/A	N/A	45.24
Cincinnati Gas & Electric co												
1996	East Bend	Quarto Mining Consol	Various	OH	Barge	–	0.010	4.44	12136	N/A	N/A	22.95
1996	Miami Fort	Quarto Mining Consol	Various	OH	Barge	–	0.024	4.45	12200	N/A	N/A	22.93
1996	W H Zimmer	Quarto Mining Consol	Various	OH	Barge	–	0.381	4.45	12186	N/A	N/A	22.48
1996	Walter C Beckjord	Quarto Mining Consol	Various	OH	Barge	–	0.025	4.30	12217	N/A	N/A	22.62
1999	East Bend	Addington Mining Inc	Various	KY	Barge	–	0.090	0.86	11849	N/A	N/A	28.89
1999	East Bend	Amvest Coal Sales	5 Block, Coalburg	WV	Barge	–	0.047	0.70	12280	N/A	N/A	31.90
1999	East Bend	Cyprus Amax	Pittsburgh 8	PA	Barge	–	0.088	2.35	13106	N/A	N/A	27.59
1999	Miami Fort	Addington Mining Inc	Various	KY	Barge	–	0.239	0.85	11855	N/A	N/A	28.91
1999	Miami Fort	Amvest Coal Sales	5 Block, Coalburg	WV	Barge	–	0.324	0.69	12295	N/A	N/A	31.73
1999	Miami Fort	Cyprus Amax	Pittsburgh 8	PA	Barge	–	0.091	2.23	12977	N/A	N/A	27.24
1999	W H Zimmer	Addington Mining Inc	Various	KY	Barge	–	0.023	0.82	11844	N/A	N/A	29.04
1999	W H Zimmer	Cyprus Amax	Pittsburgh 8	PA	Barge	–	0.005	2.13	13096	N/A	N/A	27.17

See notes at end of table

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DOE024-1096

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Cincinnati Gas & Electric Co (continued)												
1999	Walter C Beckjord	Addington Mining Inc	Various	KY	Barge	–	0.456	0.87	11868	N/A	N/A	28.73
1999	Walter C Beckjord	Amvest Coal Sales	5 Block, Coalburg	WV	Barge	–	0.007	0.69	12370	N/A	N/A	31.78
1999	Walter C Beckjord	Cyprus Amax	Pittsburgh 8	PA	Barge	–	0.078	1.91	12723	N/A	N/A	26.90
2000	East Bend	Addington Inc	Ohio	OH	Barge	–	0.043	3.04	11664	N/A	N/A	28.47
2000	Miami Fort	Addington Inc	Ohio	OH	Barge	–	0.030	3.03	11649	N/A	N/A	28.46
2000	Miami Fort	Addington Inc	Ohio	OH	Barge	–	0.004	2.79	11595	N/A	N/A	28.56
2000	W H Zimmer	Addington Inc	Ohio	OH	Barge	–	0.341	2.96	11585	N/A	N/A	28.09
2000	W H Zimmer	Addington Inc	Ohio	OH	Barge	–	0.193	2.91	11472	N/A	N/A	27.94
2000	W H Zimmer	Addington Inc	Ohio	OH	Barge	–	0.233	2.82	11581	N/A	N/A	28.25
2000	Walter C Beckjord	Addington Inc	Ohio	OH	Barge	–	0.014	3.04	11646	N/A	N/A	28.38
2000	Walter C Beckjord	Addington Inc	Ohio	OH	Barge	–	0.013	2.82	11525	N/A	N/A	28.16
2003	East Bend	American Coals Sales	Pitt 8/Upper Frpt 7	OH	Barge	–	0.040	4.32	12555	N/A	N/A	25.96
2003	Miami Fort	American Coals Sales	Pitt 8/Upper Frpt 7	OH	Barge	–	0.010	4.32	12475	N/A	N/A	25.55
2003	W H Zimmer	American Coals Sales	Pitt 8/Upper Frpt 7	OH	Barge	–	0.830	4.23	12561	N/A	N/A	25.92
2003	Walter C Beckjord	American Coals Sales	Pitt 8/Upper Frpt 7	OH	Barge	–	0.004	3.95	12650	N/A	N/A	27.84
2003	Walter C Beckjord	American Coals Sales	Pitt 8/Upper Frpt 7	OH	Barge	–	0.018	4.31	12507	N/A	N/A	25.61
2004	East Bend	Hansford Coal Co	Various	WV	Barge	–	0.069	0.75	12276	N/A	N/A	34.51
2004	East Bend	Peabody Holding Co	Pittsburgh #8	WV	Barge	–	0.414	2.25	13225	N/A	N/A	29.27
2004	Miami Fort	Hansford Coal Co	Various	WV	Barge	–	0.381	0.68	12348	N/A	N/A	38.89
2004	Miami Fort	Peabody Holding Co	Pittsburgh #8	WV	Barge	–	0.210	2.24	13238	N/A	N/A	29.35
2004	W H Zimmer	Peabody Holding Co	Pittsburgh #8	WV	Barge	–	0.044	2.23	13174	N/A	N/A	28.64
2004	Walter C Beckjord	Hansford Coal Co	Various	WV	Barge	–	0.410	0.81	12157	N/A	N/A	30.99
2004	Walter C Beckjord	Peabody Holding Co	Pittsburgh #8	WV	Barge	–	0.112	2.32	13275	N/A	N/A	28.97
Cleveland Electric Illum co												
1998	Eastlake	Cyprus Coal	Emerald	PA	Train	233	0.716	2.21	13205	N/A	N/A	36.49
1999	Ashtabula	Ohio Valley Coal Co	Powhatan	OH	Train	232	0.469	3.71	12477	N/A	N/A	28.71
1999	Eastlake	Ohio Valley Coal Co	Powhatan	OH	Train	193	0.648	3.75	12790	N/A	N/A	27.29
2001	Avon Lake	Mingo Logan Coal Co	Lowgap	WV	Train	393	0.957	0.72	12966	N/A	N/A	41.01
2003	Avon Lake	A T Massey Coal Co	Sprouse Creek,Sidney	WV	Train	360	0.189	0.74	12783	N/A	N/A	40.56
Consumers Power co												
1997	Campbell	Arch Coal Sales Co	Fanco	WV	Train	567	0.182	0.65	12527	N/A	N/A	42.89
1997	Campbell	Bluegrass Coal	McVicker	KY	Train	594	0.212	0.65	12768	N/A	N/A	42.15
1997	Campbell	Kerr McGee Coal Corp	Jacobs Ranch	WY	Train	1,298	0.233	0.48	8706	N/A	N/A	20.76
1997	Campbell	Pittston Coal Sales	Elkay	KY	Train	579	0.144	0.67	12238	N/A	N/A	43.15
1997	Campbell	Pittston Coal Sales	Elkay	KY	Train	579	0.093	0.78	12257	N/A	N/A	43.00
1997	Cobb	Pittston Coal Sales	Elkay	KY	Multimode	980	0.007	0.74	12074	N/A	N/A	43.80
1997	Dan E Karn	Amvest Coal Sales	Fola	WV	Train	519	0.082	0.75	12409	N/A	N/A	40.46
1997	Dan E Karn	Kerr McGee Coal Corp	Jacobs Ranch	WY	Train	1,459	0.012	0.50	8689	N/A	N/A	22.14
1997	Weadock	Amvest Coal Sales	Fola	WV	Train	519	0.024	0.80	12656	N/A	N/A	41.01
1997	Whiting	Pittston Coal Sales	Elkay	KY	Train	380	0.010	0.75	12414	N/A	N/A	40.48

See notes at end of table

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Consumers Power Co (continued)												
2002	Campbell	Quaker Coal Co	Sidewinder	KY	Train	566	0.374	0.81	12903	N/A	N/A	44.44
2002	Campbell	Quaker Coal Co	Sidewinder	KY	Train	566	0.000	0.82	13017	N/A	N/A	45.10
2002	Cobb	Quaker Coal Co	Sidewinder	KY	Multimode	970	0.008	0.86	13080	N/A	N/A	46.65
2002	Dan E Kam	Quaker Coal Co	Sidewinder	KY	Train	506	0.020	0.82	12509	N/A	N/A	40.79
2002	Whiting	Quaker Coal Co	Sidewinder	KY	Train	370	0.009	0.85	12945	N/A	N/A	41.68
2003	Campbell	Arch Coal Sales Co	Hobet	WV	Train	579	0.603	0.65	12206	N/A	N/A	44.53
2003	Campbell	Arch Coal Sales Co	Moncio	WV	Train	579	0.113	0.78	12023	N/A	N/A	41.65
2003	Dan E Kam	Arch Coal Sales Co	Moncio	WV	Train	519	0.122	0.82	12055	N/A	N/A	39.31
2003	Weadock	Arch Coal Sales Co	Moncio	WV	Train	519	0.061	0.76	12049	N/A	N/A	39.29
2003	Whiting	Arch Coal Sales Co	Moncio	WV	Train	380	0.511	0.80	12065	N/A	N/A	38.36
2004	Campbell	Arch Coal Sales	Hobet	WV	Train	579	0.360	0.78	12081	N/A	N/A	42.59
2004	Campbell	Arch Coal Sales	Hobet	WV	Train	579	0.030	0.70	12244	N/A	N/A	42.92
2004	Cobb	Arch Coal Sales	Hobet	WV	Multimode	970	0.036	0.71	12132	N/A	N/A	43.76
2004	Dan E Kam	Amvest Coal Sales	Fola	WV	Train	519	0.162	0.75	12484	N/A	N/A	37.81
2004	Dan E Kam	Arch Coal Sales	Hobet	WV	Train	519	0.062	0.81	12057	N/A	N/A	40.05
2004	Weadock	Amvest Coal Sales	Fola	WV	Train	519	0.060	0.73	12459	N/A	N/A	37.83
2004	Weadock	Arch Coal Sales	Hobet	WV	Train	519	0.042	0.83	12055	N/A	N/A	40.29
2004	Whiting	Amvest Coal Sales	Fola	WV	Train	380	0.010	0.84	12640	N/A	N/A	37.61
2004	Whiting	Arch Coal Sales	Hobet	WV	Train	380	0.090	0.80	12125	N/A	N/A	39.29
Dayton Power & Light co												
1997	Killen Station	Riverwood Coal Sales	Hannco No 3	KY	Barge	76	0.298	0.63	11720	N/A	N/A	2.84
1998	O H Hutchings	Amvest Coal Sales	Fola	WV	Train	338	0.269	0.74	12699	N/A	N/A	35.36
1999	J M Stuart	Arch Coal Sales Co	Various	WV	Multimode	201	0.271	0.70	11907	N/A	N/A	34.91
1999	J M Stuart	Arch Coal Sales Co	Various	WV	Barge	203	0.271	0.70	11907	N/A	N/A	34.91
1999	J M Stuart	Ashland Coal Inc	Various	WV	Barge	93	0.638	0.73	11514	N/A	N/A	24.95
1999	J M Stuart	James River Coal Co	Stone	KY	Multimode	203	0.370	0.89	12236	N/A	N/A	38.35
1999	J M Stuart	James River Coal Co	Stone	KY	Multimode	213	0.370	0.89	12236	N/A	N/A	38.35
1999	Killen Station	Arch Coal Sales Co	Various	WV	Multimode	186	0.503	0.62	12195	N/A	N/A	37.91
2000	J M Stuart	Cyprus Amax Coal	Various	KY	Multimode	199	0.620	0.84	11537	N/A	N/A	40.01
2000	J M Stuart	Cyprus Amax Coal	Various	KY	Barge	223	0.620	0.84	11537	N/A	N/A	40.01
2000	J M Stuart	Pen Coal Corp	Various	WV	Barge	91	1.272	0.85	11446	N/A	N/A	27.15
2000	Killen Station	Cyprus Amax Coal	Various	KY	Barge	208	0.546	0.63	12121	N/A	N/A	28.70
2000	Killen Station	Pen Coal Corp	Various	WV	Barge	76	0.013	0.61	11825	N/A	N/A	27.24
Delmarva Power & Light co												
1997	Edge Moor	Amvest Coal Sales	Fola	WV	Train	850	0.063	0.68	12494	N/A	N/A	41.00
1997	Indian River	Amvest Coal Sales	Coalburg & Stockton	WV	Train	950	0.051	0.67	12585	N/A	N/A	43.86
1997	Indian River	Min Inc	Cedar Grove, Alma	WV	Train	720	0.232	0.74	13285	N/A	N/A	47.11
1999	Edge Moor	Anker Energy Corp	Freeport,Kittanning	WV	Train	550	0.062	0.73	12900	28.66	14.19	42.85
1999	Edge Moor	Coastal Coal Inter	Kittanning	VA	Train	600	0.187	0.86	13197	N/A	N/A	41.96
1999	Indian River	Anker Energy Corp	Mettiki	MD	Train	450	0.061	1.45	13158	N/A	N/A	39.42

See notes at end of table

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DOE024-1098

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Detroit Edison Co (continued)												
2001	Belle River	Spring Creek Coal Co	Spring Creek	MT	Multimode	1,713	1.198	0.36	9383	N/A	N/A	24.08
2001	Monroe	Arco (Thunder Basin)	Black Thunder	WY	Train	1,621	1.846	0.35	8756	N/A	N/A	18.36
2001	Monroe	Arco (Thunder Basin)	Black Thunder	WY	Multimode	1,974	0.461	0.35	8756	N/A	N/A	18.36
2001	Monroe	Powder River Coal	Rochelle,N Antelope	WY	Train	1,490	1.672	0.23	8857	N/A	N/A	18.61
2001	Monroe	Powder River Coal	Rochelle,N Antelope	WY	Multimode	1,794	0.279	0.23	8857	N/A	N/A	18.61
2001	River Rouge	Arco (Thunder Basin)	Black Thunder	WY	Train	1,233	0.427	0.35	8765	N/A	N/A	18.20
2001	River Rouge	Powder River Coal	Rochelle,N Antelope	WY	Train	1,525	0.194	0.22	8839	N/A	N/A	18.50
2001	St Clair	Arco (Thunder Basin)	Black Thunder	WY	Multimode	1,845	0.150	0.37	8734	N/A	N/A	17.69
2001	St Clair	Spring Creek Coal Co	Spring Creek	MT	Multimode	1,713	1.240	0.36	9384	N/A	N/A	24.06
2001	Trenton Channel	Arco (Thunder Basin)	Black Thunder	WY	Train	1,871	0.129	0.34	8712	N/A	N/A	18.87
2005	Belle River	Decker Coal Co	West Decker	MT	Multimode	1,713	2.525	0.36	9530	N/A	N/A	31.81
2005	St Clair	Decker Coal Co	West Decker	MT	Multimode	1,713	2.631	0.36	9530	N/A	N/A	31.81
Duke Power co												
1997	Belews Creek	Central Coal Co, Inc	Sadie	WV	Train	281	0.042	0.74	12324	N/A	N/A	32.33
1997	Belews Creek	Logan & Kanawha Coal	Hampden	WV	Train	281	0.022	0.76	12709	N/A	N/A	34.23
1997	Belews Creek	Massey Coal Sales Co	Sidney	KY	Train	334	0.021	1.17	12608	N/A	N/A	33.34
1997	Belews Creek	Neweagle Coal Sales	Camp Creek Complex	WV	Train	414	0.109	0.87	12568	N/A	N/A	32.76
1997	Buck	Sunny Ridge Entrpse	Various	KY	Train	336	0.040	1.03	12312	N/A	N/A	33.01
1997	Cliffside	Manalapan Mining Co	Various	KY	Train	319	0.640	1.15	12709	N/A	N/A	48.52
1997	Dan River	Sunny Ridge Entrpse	Various	KY	Train	262	0.098	1.13	12584	N/A	N/A	33.33
1997	G G Allen	Central Coal Co, Inc	Sadie	WV	Train	374	0.393	0.74	12296	N/A	N/A	31.99
1997	G G Allen	Neweagle Coal Sales	Camp Creek Complex	WV	Train	473	0.236	0.89	12483	N/A	N/A	32.69
1997	G G Allen	Pevler Coal Sales	Pevler #1	KY	Train	416	0.011	1.13	12099	N/A	N/A	31.47
1997	G G Allen	Sunny Ridge Entrpse	Various	KY	Train	374	0.167	1.14	12645	N/A	N/A	33.40
1997	Marshall	Central Coal Co, Inc	Sadie	WV	Train	329	0.040	0.78	12181	N/A	N/A	31.34
1997	Marshall	Logan & Kanawha Coal	Hampden	WV	Train	329	0.236	0.88	12814	N/A	N/A	33.91
1997	Marshall	Massey Coal Sales Co	Sidney	KY	Train	434	0.227	1.11	12609	N/A	N/A	33.51
1997	Marshall	Neweagle Coal Sales	Camp Creek Complex	WV	Train	428	0.068	0.89	12437	N/A	N/A	32.62
1997	Marshall	Pevler Coal Sales	Pevler #1	KY	Train	371	1.248	1.19	12144	N/A	N/A	31.85
1997	Riverbend	Manalapan Mining Co	Various	KY	Train	372	0.270	1.07	12694	N/A	N/A	48.94
1997	W S Lee	Manalapan Mining Co	Various	KY	Train	385	0.098	1.13	12594	N/A	N/A	49.48
1998	Belews Creek	Mapco Coal Inc	Various	KY	Train	330	0.044	0.97	12166	N/A	N/A	31.39
1998	G G Allen	Mapco Coal Inc	Various	KY	Train	445	0.032	0.91	12071	N/A	N/A	31.49
1998	Marshall	Mapco Coal Inc	Various	KY	Train	438	1.972	0.99	12116	N/A	N/A	31.53
1999	Belews Creek	ARCH Coal, Inc	Mountaineer	WV	Train	280	1.190	0.71	12962	N/A	N/A	34.93
1999	G G Allen	ARCH Coal, Inc	Mountaineer	WV	Train	420	0.296	0.72	12980	N/A	N/A	35.06
1999	Marshall	ARCH Coal, Inc	Mountaineer	WV	Train	350	0.011	0.75	12736	N/A	N/A	34.54
2003	Belews Creek	Franklin Coal Sales	Various	KY	Train	328	0.051	0.63	12071	N/A	N/A	38.52
2003	Belews Creek	Massey Coal Sales Co	Various	KY	Train	334	3.723	0.77	12359	N/A	N/A	37.38
2003	Belews Creek	Pittston Coal Sales	Job 17	KY	Train	242	0.040	0.87	12308	N/A	N/A	32.75

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Delmarva Power & Light Co (continued)												
1999	Indian River	Anker Energy Corp	Freeport,Kittanning	WV	Train	550	0.199	0.67	12779	28.13	16.15	44.27
1999	Indian River	Courtney F Foos Coal	Lwr Freeport	MD	Train	450	0.100	1.45	13157	N/A	N/A	39.95
1999	Indian River	Eighty-Four Mining	Pittsburgh	PA	Train	455	0.402	1.39	13264	N/A	N/A	38.12
2000	Edge Moor	Coastal Coal Sales	Kittanning	WV	Train	420	0.073	0.83	13026	N/A	N/A	42.21
Detroit Edison co												
1997	Belle River	Kennecott Energy Co	Antelope	WY	Multimode	1,713	0.101	0.22	8762	N/A	N/A	18.29
1997	Harbor Beach	Kennecott Energy Co	Antelope	WY	Multimode	1,791	0.009	0.20	8657	N/A	N/A	18.84
1997	Harbor Beach	Massey Coal Sales	Elk Run, Sprouse Crk	WV	Multimode	518	0.001	1.72	13022	N/A	N/A	39.81
1997	Monroe	Branham & Baker Coal	Coon, Sidewinder	KY	Train	390	0.004	1.17	12767	N/A	N/A	42.02
1997	Monroe	Branham & Baker Coal	Coon, Sidewinder	KY	Multimode	481	0.004	1.17	12767	N/A	N/A	42.02
1997	Monroe	Kennecott Energy Co	Antelope	WY	Train	1,490	0.059	0.22	8769	N/A	N/A	18.98
1997	Monroe	Massey Coal Sales	Elk Run, Sprouse Crk	WV	Train	359	0.061	1.68	13038	N/A	N/A	37.20
1997	Monroe	Massey Coal Sales	Elk Run, Sprouse Crk	WV	Multimode	351	0.122	1.68	13038	N/A	N/A	37.20
1997	Monroe	Massey Coal Sales	Elk Run, Sprouse Crk	WV	Multimode	325	0.061	1.68	13038	N/A	N/A	37.20
1997	River Rouge	Kennecott Energy Co	Antelope	WY	Train	1,525	0.030	0.19	8758	N/A	N/A	19.08
1997	River Rouge	Kennecott Energy Co	Antelope	WY	Train	1,415	0.030	0.19	8758	N/A	N/A	19.08
1997	St Clair	Kennecott Energy Co	Antelope	WY	Train	1,713	0.110	0.21	8756	N/A	N/A	18.27
1997	Trenton Channel	Kennecott Energy Co	Antelope	WY	Train	1,510	0.755	0.22	8737	N/A	N/A	19.48
1997	Trenton Channel	Kennecott Energy Co	Antelope	WY	Train	1,205	0.755	0.22	8737	N/A	N/A	19.48
1997	Trenton Channel	Massey Coal Sales	Elk Run, Sprouse Crk	WV	Train	379	0.078	1.67	13001	N/A	N/A	36.64
1997	Trenton Channel	Massey Coal Sales	Elk Run, Sprouse Crk	WV	Train	345	0.078	1.67	13001	N/A	N/A	36.64
1999	Harbor Beach	Consol	Bailey	PA	Multimode	516	0.002	1.54	13251	N/A	N/A	35.05
1999	Harbor Beach	Quaker Coal Co Inc	Sidewinder	KY	Multimode	552	0.022	0.61	13045	N/A	N/A	39.98
1999	Marysville	Quaker Coal Co Inc	Sidewinder	KY	Multimode	552	0.007	0.68	13025	N/A	N/A	41.33
1999	Monroe	Consol	Bailey	PA	Multimode	395	1.402	1.57	13163	N/A	N/A	31.44
1999	Monroe	Consol	Jones Fork	KY	Multimode	344	0.057	0.90	12567	N/A	N/A	37.37
1999	Monroe	Consol	Jones Fork	KY	Train	353	0.057	0.90	12567	N/A	N/A	37.37
1999	Monroe	Eighty Four Mining	Mine 84	PA	Multimode	395	0.655	1.41	13293	N/A	N/A	34.30
1999	Monroe	Quaker Coal Co Inc	Sidewinder	KY	Train	347	0.144	0.75	12943	N/A	N/A	35.32
1999	Monroe	Quaker Coal Co Inc	Sidewinder	KY	Multimode	344	0.144	0.75	12943	N/A	N/A	35.32
1999	River Rouge	Ashland Coal Inc	Various	WV	Train	475	0.293	0.84	12076	N/A	N/A	35.22
1999	River Rouge	Consol	Bailey	PA	Train	408	0.021	1.56	13246	N/A	N/A	33.31
1999	River Rouge	Consol	Jones Fork	KY	Train	388	0.106	0.90	12549	N/A	N/A	38.29
1999	River Rouge	Quaker Coal Co Inc	Sidewinder	KY	Train	382	0.171	0.78	12988	N/A	N/A	36.71
1999	St Clair	Consol	Robinson	WV	Train	415	0.492	3.25	13105	N/A	N/A	31.22
1999	St Clair	Consol	Jones Fork	KY	Multimode	828	0.008	0.85	12698	N/A	N/A	41.22
1999	St Clair	Quaker Coal Co Inc	Sidewinder	KY	Multimode	448	0.024	0.67	12942	N/A	N/A	42.28
1999	Trenton Channel	Consol	Bailey	PA	Train	370	0.117	1.65	13126	N/A	N/A	33.20
1999	Trenton Channel	Eighty Four Mining	Mine 84	PA	Train	326	0.025	1.64	13240	N/A	N/A	34.27
2001	Belle River	Powder River Coal	Rochelle N Antelope	WY	Multimode	1,866	0.200	0.23	8846	N/A	N/A	18.01

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Duke Power Co (continued)												
2003	Buck	Massey Coal Sales Co	Various	KY	Train	378	0.020	0.70	12434	N/A	N/A	36.59
2003	Dan River	Massey Coal Sales Co	Various	KY	Train	304	0.020	0.84	12244	N/A	N/A	40.77
2003	G G Allen	Franklin Coal Sales	Various	KY	Train	436	0.449	0.64	12071	N/A	N/A	38.57
2003	G G Allen	Massey Coal Sales Co	Various	KY	Train	450	0.113	0.66	12599	N/A	N/A	38.40
2003	G G Allen	Pittston Coal Sales	Job 17	KY	Train	438	0.058	0.98	12288	N/A	N/A	32.61
2003	Marshall	Massey Coal Sales Co	Various	KY	Train	434	0.133	0.71	12356	N/A	N/A	37.15
2003	Marshall	Pittston Coal Sales	Job 17	KY	Train	440	0.152	1.00	12325	N/A	N/A	32.63
Duquesne Light co												
2005	Cheswick	Appalachian Mining	Various	WV	Barge	370	0.247	1.23	13248	28.27	5.39	33.66
2005	Cheswick	Quintain Res Inc	Topaz	PA	Truck	198	0.368	1.14	12916	24.75	9.52	34.27
2005	Elrama	Appalachian Mining	Various	WV	Barge	370	0.139	1.37	13195	28.1	5.37	33.47
Electric Energy Inc												
1997	Joppa Steam	Rochelle Coal Co	Rochelle, PRB	WY	Train	1,260	2.146	0.22	8856	N/A	N/A	15.71
1999	Joppa Steam	Amax Coal West Inc	Belle Ayr, PRB	WY	Train	1,302	1.834	0.25	8582	N/A	N/A	14.53
2000	Joppa Steam	Kennecott Energy Co	Caballo Rojo, PRB	WY	Train	1,240	0.601	0.33	8434	N/A	N/A	13.93
Empire District Electric co												
1999	Asbury	Mackie-Clemens Fuel	Clemens	KS	Truck	35	0.079	3.34	11869	N/A	N/A	31.45
1999	Riverton	Mackie-Clemens Fuel	Clemens	KS	Truck	45	0.063	3.42	12366	N/A	N/A	30.75
2004	Asbury	Powder River Coal Co	Rochelle, N Antelope	WY	Train	876	0.653	0.28	8696	N/A	N/A	17.90
2004	Riverton	Powder River Coal Co	Rochelle, N Antelope	WY	Train	904	0.208	0.26	8746	N/A	N/A	20.50
Florida Power & Light co												
2000	St Johns River	Shamrock Coal	Beechfork	KY	Train	717	1.000	1.28	12863	N/A	N/A	46.40
2002	St Johns River	Ashland Coal Inc	Hobet	WV	Train	1,110	0.630	0.74	12118	N/A	N/A	44.95
Florida Power Corp												
1997	Crystal River	Ashland Coal, Inc 2	Coal Mac III	KY	Train	837	0.137	0.71	13028	N/A	N/A	43.73
1997	Crystal River	Quaker Coal Co (2)	Various	KY	Barge	1,992	0.055	0.63	13054	N/A	N/A	53.64
1997	Crystal River	Quaker Coal Co (2)	Various	KY	Train	841	0.380	0.63	13054	N/A	N/A	43.83
1998	Crystal River	Cyprus Cumberland	Straight Creek	KY	Train	829	0.446	1.12	12658	N/A	N/A	40.90
1999	Crystal River	Arch Coal Sales Co	Lynch 3	KY	Train	843	0.405	1.05	13225	N/A	N/A	45.20
2001	Crystal River	Pen Coal Corp	Various	KY	Barge	1,997	0.431	0.65	12542	N/A	N/A	56.47
2002	Crystal River	AT Massey Coal Co	Sidney,Elk Run	WV	Barge	2,052	0.656	0.73	12642	N/A	N/A	54.30
2002	Crystal River	Franklin Coal Sales	McVicker, Slones Br	KY	Barge	1,992	0.009	0.68	12764	N/A	N/A	54.56
2002	Crystal River	Franklin Coal Sales	McVicker, Slones Br	KY	Train	836	0.221	0.68	12764	N/A	N/A	44.75
2002	Crystal River	Powell Mountain	Mayflower	VA	Train	876	0.873	0.73	12337	N/A	N/A	51.93
Gulf Power co												
2007	Crist	Peabody Coalsales Co	Gallatia,Paso Diablo	IL	Barge	80	0.320	1.12	12148	N/A	N/A	50.75
2007	Crist	Peabody Coalsales Co	Gallatia,Paso Diablo	IL	Barge	1,440	0.320	1.12	12148	N/A	N/A	50.75
2007	Lansing Smith	Peabody Coalsales Co	Gallatia,Paso Diablo	IL	Barge	187	0.022	1.11	12108	N/A	N/A	51.08
2007	Lansing Smith	Peabody Coalsales Co	Gallatia,Paso Diablo	IL	Barge	1,440	0.022	1.11	12108	N/A	N/A	51.08

See notes at end of table

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DOE024-1101

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Gulf States Utilities Co												
2004	R S Nelson	Kerr-McGee Coal Corp	Jacobs Ranch	WY	Train	1,576	1.992	0.48	8711	N/A	N/A	24.28
Holyoke Water Power co												
1997	Mount Tom	Massey Coal Sales	Sidney	VA	Train	1,100	0.016	0.61	12846	29.32	23.82	51.31
1998	Mount Tom	Consol Inc	Bailey	PA	Train	755	0.024	1.46	13207	25.3	18.58	43.87
1998	Mount Tom	Cyprus Amax	Emerald	PA	Train	755	0.199	1.37	13201	26.37	18.03	45.20
1998	Mount Tom	Pittston Coal Sales	Holston	KY	Train	1,100	0.103	0.51	13069	30.1	24.24	54.07
2001	Mount Tom	United Eastern	Mine 84	PA	Train	755	0.033	1.26	13347	25.57	18.22	43.25
Indiana Michigan Power co												
1998	Tanners Creek	Amax Coal Sales Co	Various	KY	Barge	312	0.476	0.65	12423	N/A	N/A	44.61
1999	Tanners Creek	Golden Oak Mining Co	Godlen Oak No 3 & 3A	KY	Multimode	315	0.493	1.46	13348	N/A	N/A	35.93
1999	Tanners Creek	Vandalia Co	Magic	KY	Barge	334	0.224	2.19	11566	N/A	N/A	25.58
2004	Rockport (Proj 2601)	Rochelle Coal Co	Rochelle,N Antelope	WY	Multimode	1,478	4.971	0.22	8819	N/A	N/A	19.79
2004	Tanners Creek	Rochelle Coal Co	Rochelle,N Antelope	WY	Multimode	1,729	0.054	0.21	8919	N/A	N/A	22.38
2014	Rockport (Proj 2601)	Caballo Coal Co	Rawhide,Caballo	WY	Multimode	1,475	3.011	0.34	8461	N/A	N/A	17.67
Indianapolis Power & Light co												
1997	Petersburg	Black Beauty Coal Co	West Fork	IN	Truck	26	0.139	2.06	11146	N/A	N/A	17.72
1997	Petersburg	Kindill Mining Inc	Kindill #1	IN	Train	28	0.011	3.60	11316	N/A	N/A	18.22
1997	Petersburg	PNR Coal Sales Corp	AMC, South	IN	Truck	24	0.311	2.31	11123	N/A	N/A	17.68
1997	Petersburg	PNR Coal Sales Corp	Midway	IN	Truck	24	0.288	2.25	11127	N/A	N/A	17.69
1998	Elmer W Stout	Kindill Mining Inc	Kindill #3	IN	Train	108	0.139	0.95	10907	N/A	N/A	21.34
1998	H T Pritchard	Kindill Mining Inc	Kindill #3	IN	Train	81	0.259	1.00	10783	N/A	N/A	20.44
1998	Petersburg	Black Beauty Coal	West Fork	IN	Truck	26	0.076	1.88	11154	N/A	N/A	19.09
1998	Petersburg	Black Beauty Coal Co	Columbia	IN	Truck	20	0.181	3.02	11650	N/A	N/A	20.42
1998	Petersburg	Layfayette Coal Co	Pride	IN	Truck	4	0.629	2.62	11042	N/A	N/A	17.33
1998	Petersburg	Peabody Coalsales Co	Hawthorn	IN	Train	42	0.054	1.98	10671	N/A	N/A	13.70
1999	Elmer W Stout	Black Beauty Coal Co	Various	IN	Train	89	0.492	1.32	11183	N/A	N/A	26.67
1999	Petersburg	Black Beauty Coal Co	Various	IN	Truck	19	0.500	1.94	11507	N/A	N/A	24.39
2000	Elmer W Stout	Triad Mining of IN	Switz City	IN	Train	85	0.118	1.27	11285	N/A	N/A	25.99
2000	H T Pritchard	Triad Mining of IN	Switz City	IN	Train	52	0.185	1.30	11431	N/A	N/A	25.86
2000	Perry K	Triad Mining of IN	Switz City	IN	Train	80	0.249	1.04	11253	N/A	N/A	28.37
2007	Petersburg	Peabody Coal Co	Lynnville, Hawthorn	IN	Train	28	0.976	3.02	10971	N/A	N/A	23.48
2007	Petersburg	Peabody Coal Co	Lynnville, Hawthorn	IN	Train	42	0.976	3.02	10971	N/A	N/A	23.25
2011	Elmer W Stout	Black Beauty Coal Co	Farmersburg	IN	Train	112	0.656	1.14	10868	N/A	N/A	23.48
2011	H T Pritchard	Black Beauty Coal Co	Farmersburg	IN	Train	85	0.058	1.15	10784	N/A	N/A	22.64
Interstate Power co												
1997	Dubuque	CONSOL, Inc	Rend Lake	IL	Barge	–	0.015	2.70	11791	N/A	N/A	28.09
1997	Lansing	CONSOL, Inc	Rend Lake	IL	Barge	–	0.028	2.70	11791	N/A	N/A	28.09
1998	Lansing	Amax Coal Co	BelleAyr,Eagle Butte	WY	Multimode	1,253	0.559	0.31	8465	N/A	N/A	36.68
1999	Milton L Kapp	Powderhorn Coal Co	Roadside-Cameo	CO	Train	–	0.426	0.53	11497	16.17	15.35	31.51

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Iowa Electric Light & Power												
1997	Praire Creek	Caballo Rojo Inc	Caballo Rojo	WY	Train	955	0.770	0.33	8427	N/A	N/A	16.64
1997	Sutherland	Caballo Rojo Inc	Caballo Rojo	WY	Train	890	0.441	0.36	8515	N/A	N/A	13.71
Iowa Southern Utilities co												
1997	Burlington	Caballo Rojo Inc	Caballo Rojo	WY	Train	934	0.091	0.38	8453	N/A	N/A	14.13
1997	Ottumwa	Peabody Coal Sales	Rawhide	WY	Train	851	0.453	0.32	8339	N/A	N/A	12.13
2001	Ottumwa	Kennecott Energy Co	Cordero	WY	Train	857	0.782	0.37	8366	N/A	N/A	18.18
Iowa-Illinois Gas & Electric												
1997	Louisa	Caballo Rojo Inc	Various	WY	Train	934	0.132	0.32	8301	N/A	N/A	13.53
1997	Louisa	Powder River Coal	Rawhide	WY	Train	934	0.012	0.26	8476	N/A	N/A	15.37
1997	Riverside	Caballo Rojo Inc	Various	WY	Train	969	0.381	0.32	8446	N/A	N/A	16.01
1999	Louisa	Amax Coal West, Inc	Eagle Butte,BelleAyr	WY	Train	934	0.322	0.36	8331	N/A	N/A	18.85
1999	Louisa	Powder River Coal Co	Caballo & Rawhide	WY	Train	961	0.090	0.38	8504	N/A	N/A	14.38
2003	Louisa	Cordero Mining Co	Cordero	WY	Train	934	1.411	0.35	8381	N/A	N/A	19.13
Kansas City Power & Light co												
1997	LaCygne	Caballo Rojo Inc	Caballo Rojo	WY	Train	875	0.726	0.31	8435	N/A	N/A	10.73
1997	Montrose	Peabody COALSALES Co	N Antelope, Rochelle	WY	Train	926	1.584	0.20	8692	N/A	N/A	17.21
1998	Hawthorn	ARCO Coal Co	BlackThund/CoalCrk	WY	Train	875	1.328	0.34	8755	N/A	N/A	12.10
1998	Iatan	ARCO Coal Co	BlackThund/CoalCrk	WY	Train	796	0.171	0.34	8591	N/A	N/A	11.25
1998	LaCygne	ARCO Coal Co	BlackThund/CoalCrk	WY	Train	875	0.567	0.34	8354	N/A	N/A	11.88
1998	LaCygne	ARCO Coal Co	BlackThund/CoalCrk	WY	Train	875	0.175	0.35	8786	N/A	N/A	12.36
1999	Iatan	Peabody Coal Sales	Caballo	WY	Train	796	0.122	0.36	8529	N/A	N/A	9.72
1999	LaCygne	Peabody Coal Sales	Caballo	WY	Train	875	2.137	0.37	8521	N/A	N/A	10.83
1999	Montrose	Peabody Coal Sales	Caballo	WY	Train	926	0.069	0.40	8549	N/A	N/A	14.97
2003	Iatan	Arco Coal Co	Black Thunder	WY	Train	796	2.300	0.35	8745	N/A	N/A	14.51
Kansas Power & Light co												
1998	Lawrence	Cyprus Western Coal	Foidel	CO	Train	1,037	0.645	0.46	11473	N/A	N/A	29.43
1998	Tecumseh	Cyprus Western Coal	Foidel	CO	Train	1,045	0.263	0.46	11312	N/A	N/A	28.97
2013	Jeffrey Energy Cnt	Amax Coal West	Eagle Butte,Belle Ay	WY	Train	697	8.254	0.37	8348	N/A	N/A	19.22
Kentucky Power co												
1998	Big Sandy	Holland/Electric	Various	KY	Train	100	0.226	1.28	12325	N/A	N/A	26.88
1999	Big Sandy	Quaker Coal Co	Various	KY	Train	58	0.341	1.30	12159	N/A	N/A	29.08
Kentucky Utilities co												
1997	E W Brown	Arch Coal Sales Co	Ridgeline	KY	Train	123	0.259	1.47	12086	23.97	6.75	30.73
1997	E W Brown	Pine Branch Coal Sal	Comb Branch,Haddock	KY	Train	160	0.434	1.10	11927	24.57	6.74	31.31
1997	Ghent	Pyramid Mining Inc	West Kentucky 4,6,9	KY	Truck	30	0.143	2.54	12073	22.74	2.56	25.29
1998	Ghent	Ashland Coal	Hobet, Boyd, Nicks	WV	Multimode	330	0.374	0.65	12154	23.24	6.44	29.68
1998	Ghent	Ashland Coal Inc	Coalburg 6,8,9,11	WV	Multimode	330	0.354	0.66	12144	25.92	6.98	32.88
1998	Ghent	Cannelton, Inc	Various	WV	Barge	354	0.308	0.67	12423	26.93	3.31	30.24
1998	Ghent	Knott-Floyd Land Co	Motts, 1, 2, 3,4	KY	Multimode	340	0.279	0.67	12327	24.5	5.98	30.47
1998	Ghent	Pen Coal Corporation	Devilstrace Branch 2	WV	Barge	283	0.299	0.65	12147	26.05	7.08	33.14

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Kentucky Utilities Co (continued)												
1999	Ghent	Arch Coal Sales Co	Red Warrior	WV	Multimode	307	0.659	0.70	12543	26.61	5.98	32.59
2000	Ghent	Black Beauty Coal Co	Columbia, Francisco	IN	Barge	283	0.277	3.26	11354	18.30	4.59	22.87
2000	Ghent	Consol Inc	Shoemaker	WV	Barge	442	0.667	3.39	12270	19.43	2.37	21.81
2000	Ghent	Lanham Mining Co Inc	Lanham No 5	KY	Barge	224	0.218	3.06	11083	18.85	3.30	22.13
Metropolitan Edison co												
1997	Portland	Consolidation Coal	Various	WV	Train	429	0.630	1.97	13212	22.21	14.26	36.47
1997	Titus	Consolidation Coal	Various	PA	Train	290	0.481	1.57	13146	24.43	13.12	37.56
Midwest Power Systems Inc												
1997	Council Bluffs	Amax Coal West Inc	Eagle Butte	WY	Train	663	0.200	0.43	8395	N/A	N/A	10.61
1997	Council Bluffs	Powder River Coal Co	Rawhide	WY	Train	665	0.668	0.34	8337	N/A	N/A	12.57
1997	George Neal	Caballo Rojo Inc	Various	WY	Train	736	1.440	0.32	8446	N/A	N/A	11.70
1997	George Neal	Caballo Rojo Inc	Caballo Rojo	WY	Train	965	0.455	0.37	8464	N/A	N/A	11.88
1998	George Neal	Powder River Coal Co	Caballo	WY	Train	744	1.800	0.36	8510	N/A	N/A	13.18
1999	Council Bluffs	Amax Coal West Inc	Eagle Butte,Belle Ay	WY	Train	663	1.517	0.35	8324	N/A	N/A	15.44
1999	George Neal	Powder River Coal Co	Caballo & Rawhide	WY	Train	744	1.421	0.37	8513	N/A	N/A	11.80
Minnesota Power & Light co												
1999	Boswell Energy Cente	Decker Coal Co	Decker	MT	Train	1,036	0.108	0.39	9386	N/A	N/A	21.80
1999	Boswell Energy Cente	Peabody Coal Co	Big Sky	MT	Train	833	1.942	0.73	8814	N/A	N/A	20.96
1999	Syl Laskin	Decker Coal Co	Decker	MT	Train	1,121	0.412	0.39	9386	N/A	N/A	21.71
2000	Boswell Energy Cente	Kennecott Energy	Spring Creek	MT	Train	1,036	1.702	0.35	9404	N/A	N/A	19.89
Mississippi Power co												
1997	Victor J Daniel Jr	Decker Coal Co	Decker	MT	Train	1,800	3.221	0.39	9408	N/A	N/A	27.91
1998	Jack Watson	Kerr Mcgee	Galatia Mine	IL	Barge	85	1.090	1.18	11885	N/A	N/A	33.48
Missouri Public Service co												
2000	Sibley	Arch Coal Sales Co	Medicine Bow,Seminoe	WY	Train	750	0.454	0.54	10346	N/A	N/A	22.69
2000	Sibley	Arch Coal Sales Co	Medicine Bow,Seminoe	WY	Train	750	0.454	0.81	10615	N/A	N/A	23.08
2000	Sibley	Peabody Coal Sales	Rochelle	WY	Train	760	0.505	0.27	8837	N/A	N/A	13.51
Monongahela Power co												
1997	Harrison	Eastern Assoc Coal	Federal	WV	Train	180	0.677	2.43	12719	23.9	4.91	28.80
1997	Pleasants	American Coal Sales	Powhatan #6	OH	Barge	50	0.391	3.91	12577	18.64	0.87	19.51
1997	Pleasants	Eastern Assoc Coal	Federal	WV	Train	267	0.007	2.66	12366	23.21	2.13	31.83
1998	Fort Martin	Consolidation Coal	Dilworth	PA	Barge	5	1.780	1.52	12742	35.58	0.38	38.90
1999	Harrison	Continental Coal	Italy	WV	Truck	40	0.244	3.16	12996	29.05	3.02	32.07
2001	Pleasants	CONSOL	Various	WV	Barge	50	1.453	4.01	12178	19.61	0.87	20.35
2002	Fort Martin	Consol	Robinson Run	PA	Barge	5	0.493	1.46	12619	26.11	0.38	26.49
2002	Pleasants	American Coal Sales	Powhatan #6	OH	Barge	50	1.193	3.90	12565	22.28	0.87	22.87
Montana-dakota Utilities co												
2000	R M Heskett	Knife River Coal	Beulah	ND	Train	70	0.350	0.78	7035	N/A	N/A	16.06
Nevada Power co												
1997	Reid Gardner	Coop Mining Co	Bear Canyon	UT	Train	453	0.048	0.61	11551	N/A	N/A	32.58

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Nevada Power Co (continued)												
1999	Reid Gardner	SUFCO	SUFCO	UT	Train	399	0.413	0.37	11387	N/A	N/A	26.87
2002	Reid Gardner	Arco Coal Co	West Elk	CO	Train	714	0.048	0.55	11726	N/A	N/A	50.57
2004	Reid Gardner	Andalex Resources In	Various	UT	Train	447	0.087	0.75	11967	N/A	N/A	34.61
2007	Reid Gardner	Cyprus Western Coal	Wattis	UT	Train	458	0.338	0.56	11591	N/A	N/A	31.47
2006	Reid Gardner	SUFCO	SUFCO	UT	Train	399	0.075	0.37	11387	N/A	N/A	26.87
New England Power co												
1997	Brayton Point	Mingo Logan Coal Co	Various	WV	Multimode	852	0.202	0.71	12864	N/A	N/A	45.62
1997	Brayton Point	Pittston Coal Sales	Rum Creek	WV	Multimode	959	0.283	0.67	12260	N/A	N/A	41.98
1997	Salem Harbor	Pittston Coal Sales	Rum Creek	WV	Multimode	1,134	0.040	0.67	12260	N/A	N/A	43.73
1998	Brayton Point	Arch Coal Sales Co	Various	WV	Multimode	800	0.032	0.71	12864	N/A	N/A	45.62
1998	Brayton Point	Arch Coal Sales Co	Various	WV	Multimode	850	0.032	0.71	12864	N/A	N/A	45.62
1998	Brayton Point	Arch Coal Sales Co	Various	WV	Multimode	985	0.032	0.71	12864	N/A	N/A	45.62
1998	Brayton Point	Arch Coal Sales Co	Various	WV	Multimode	866	0.032	0.71	12864	N/A	N/A	45.62
1998	Brayton Point	Arch Coal Sales Co	Various	WV	Multimode	993	0.032	0.71	12864	N/A	N/A	45.62
1998	Brayton Point	Arch Coal Sales Co	Samples	WV	Multimode	841	0.259	0.68	12654	N/A	N/A	43.84
1998	Brayton Point	Ashland Coal Inc	Dalex, Hobet	WV	Multimode	911	0.091	0.73	12268	N/A	N/A	42.25
1998	Brayton Point	Ashland Coal Inc	Dalex, Hobet	WV	Multimode	890	0.091	0.73	12268	N/A	N/A	42.25
1998	Salem Harbor	Arch Coal Sales Co	Samples	WV	Multimode	1,016	0.037	0.68	12654	N/A	N/A	44.61
1998	Salem Harbor	Ashland Coal Inc	Dalex, Hobet	WV	Multimode	1,066	0.005	0.73	12268	N/A	N/A	43.25
1998	Salem Harbor	Ashland Coal Inc	Dalex, Hobet	WV	Multimode	1,065	0.005	0.73	12268	N/A	N/A	43.25
1999	Brayton Point	Mapco Coal inc	Martiki,Pontiki	KY	Multimode	852	0.282	0.68	12810	N/A	N/A	44.90
1999	Brayton Point	Massey Coal Sales Co	Various	WV	Multimode	852	0.243	0.71	12493	N/A	N/A	45.32
1999	Brayton Point	Massey Coal Sales Co	Various	WV	Multimode	902	0.209	0.71	12493	N/A	N/A	42.26
1999	Salem Harbor	Mapco Coal inc	Martiki,Pontiki	KY	Multimode	1,027	0.076	0.68	12810	N/A	N/A	47.25
1999	Salem Harbor	Massey Coal Sales Co	Various	WV	Multimode	1,077	0.040	0.71	12493	N/A	N/A	42.26
Northern States Power co												
1998	Black Dog	Kerr-McGee Coal Co	Jacobs Ranch	WY	Train	1,100	0.013	0.46	8737	N/A	N/A	17.49
1998	Sherburne County	Big Sky Coal Co	Big Sky	MT	Train	750	1.048	0.72	8819	N/A	N/A	19.41
1998	Sherburne County	Kerr-McGee Coal Co	Jacobs Ranch	WY	Train	1,100	0.135	0.46	8737	N/A	N/A	19.80
2000	Allen S King	Antelope Coal Co	Antelope Mine	WY	Train	1,100	0.528	0.24	8779	N/A	N/A	19.91
2000	Allen S King	Rochelle Coal Co	Rochelle Mine	WY	Train	1,100	0.715	0.22	8848	N/A	N/A	18.59
2000	Black Dog	Antelope Coal Co	Antelope Mine	WY	Train	1,100	0.324	0.24	8779	N/A	N/A	20.32
2000	Black Dog	Rochelle Coal Co	Rochelle Mine	WY	Train	1,100	0.501	0.22	8848	N/A	N/A	18.93
2000	High Bridge	Antelope Coal Co	Antelope Mine	WY	Train	1,100	0.006	0.24	8779	N/A	N/A	20.83
2000	High Bridge	Rochelle Coal Co	Rochelle Mine	WY	Train	1,100	0.752	0.22	8848	N/A	N/A	18.23
2000	Riverside	Antelope Coal Co	Antelope Mine	WY	Train	1,100	0.005	0.24	8779	N/A	N/A	19.57
2000	Riverside	Rochelle Coal Co	Rochelle Mine	WY	Train	1,100	1.268	0.22	8848	N/A	N/A	17.46
2000	Sherburne County	Rochelle Coal Co	Rochelle Mine	WY	Train	1,100	1.141	0.22	8848	N/A	N/A	20.30
2000	Sherburne County	Thunder Basin Coal	Black Thunder Mine	WY	Train	1,100	2.524	0.35	8753	N/A	N/A	20.46
2005	Allen S King	Westmoreland Resourc	Absaloka	MT	Train	750	0.492	0.62	8731	N/A	N/A	19.93

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Northern States Power Co (continued)												
2005	Sherburne County	Westmoreland Resourc	Absaloka	MT	Train	750	2.332	0.62	8731	N/A	N/A	19.22
Ohio Edison co												
1998	W H Sammis	Cannelton Industries	KIC	WV	Barge	297	0.451	1.44	11424	N/A	N/A	27.10
2000	W H Sammis	Cannelton Industries	Kanawha	WV	Barge	297	0.503	1.48	11419	N/A	N/A	28.39
2000	W H Sammis	Shell Mining Co/R&F	R&F	OH	Barge	72	0.435	1.21	11991	N/A	N/A	43.99
2001	W H Sammis	Buckeye/Massey Coal	Various	WV	Barge	262	0.354	0.86	12241	N/A	N/A	35.15
2001	W H Sammis	Buckeye/Massey Coal	Various	WV	Barge	280	0.295	0.84	11183	N/A	N/A	25.98
2002	Niles	Quaker Coal Co	Nelms, Beverly	OH	Train	106	0.383	2.80	12265	N/A	N/A	26.57
2002	R E Burger	Quaker Coal Co	Nelms, Beverly	OH	Barge	21	0.113	3.06	12036	N/A	N/A	22.44
2002	W H Sammis	Ashland Coal Co	Various	KY	Barge	267	0.677	0.76	12117	N/A	N/A	30.79
2002	W H Sammis	Quaker Coal Co	Nelms, Beverly	OH	Barge	28	0.004	2.14	12043	N/A	N/A	105.32
2003	W H Sammis	W B Coal Co	Campbells Creek	WV	Barge	277	0.797	0.75	12244	N/A	N/A	33.76
Ohio Power co												
2000	Muskingum River	Central Ohio Coal	Muskingum Mine	OH	Other	5	1.151	4.32	11476	N/A	N/A	60.63
2000	Muskingum River	Pittston Coal	Various	WV	Train	106	0.955	0.66	12212	N/A	N/A	34.64
2001	Gen J M Gavin	Marietta Coal	Marietta	OH	Barge	165	0.010	3.06	11610	N/A	N/A	25.70
2004	Gen J M Gavin	Sands Hill	Various	OH	Barge	16	0.812	3.00	11203	N/A	N/A	26.31
2012	Mitchell	Peabody Coal Sales	Various	WV	Multimode	345	2.507	0.76	12308	N/A	N/A	38.43
2000	Gen J M Gavin	Southern Ohio Coal	Meig 2 & 31	OH	Other	10	6.240	3.52	11349	N/A	N/A	35.13
1998	Muskogee	Amax Coal West Inc	Belle Ayr	WY	Train	1,052	2.146	0.26	8578	N/A	N/A	15.22
1998	Sooner	Amax Coal West Inc	Belle Ayr	WY	Train	931	1.567	0.25	8568	N/A	N/A	14.28
Oklahoma Gas & Electric co												
1999	Muskogee	Kennecott Energy Co	Caballo Rojo	WY	Train	1,052	0.987	0.21	8789	4.78	9.54	15.12
2003	Muskogee	Thunder Basin Coal	Black Thunder	WY	Train	1,052	1.599	0.34	8763	N/A	N/A	15.22
2003	Sooner	Thunder Basin Coal	Black Thunder	WY	Train	931	2.015	0.35	8762	N/A	N/A	14.59
2010	Muskogee	Kennecott Energy Co	Antelope	WY	Train	1,052	0.369	0.21	8789	N/A	N/A	15.18
2010	Muskogee	Powder River Coal Co	Rochelle/N Antelope	WY	Train	1,052	0.327	0.20	8764	N/A	N/A	15.71
2010	Sooner	Powder River Coal Co	Rochelle/N Antelope	WY	Train	931	0.024	0.20	8776	N/A	N/A	14.72
Otter Tail Power co												
1998	Hoot Lake	Kennecott Energy	Spring Creek	MT	Train	843	0.309	0.35	9285	N/A	N/A	23.84
1999	Big Stone	Westmoreland Res	Absaloka	MT	Train	650	1.876	0.64	8714	N/A	N/A	16.34
Pennsylvania Electric co												
1997	Conemaugh	PBS Coals Inc	PBS No 1	PA	Train	50	1.243	2.16	12696	N/A	N/A	33.52
1997	Conemaugh	Tanoma Energy Inc	Quecreek/Pine Hill	PA	Truck	39	0.109	2.18	12361	N/A	N/A	27.61
1997	Keystone	Canterbury Coal Co	David/DiAnne	PA	Truck	20	0.332	2.16	12429	N/A	N/A	27.42
1997	Keystone	Tannerystile Coal	Various	PA	Truck	10	0.042	2.07	12490	N/A	N/A	27.69
1997	Keystone	Tanoma Energy Inc	West Lebanon Strp	PA	Truck	12	0.099	2.07	12251	N/A	N/A	27.87
1997	Keystone	United Eastern Coal	Various	PA	Truck	10	0.123	2.30	12293	N/A	N/A	26.75
1997	Keystone	United Eastern Coal	Various	PA	Truck	10	0.030	2.20	12178	N/A	N/A	25.32

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price[1] (1996 Dollars)
Pennsylvania Electric Co (continued)												
1998	Keystone	Amerikohl	Various	PA	Truck	10	0.116	2.12	12479	N/A	N/A	26.86
2000	Conemaugh	Amerikohl	Nicholson/Leon	PA	Truck	35	0.020	2.70	12395	N/A	N/A	25.97
2000	Conemaugh	Amerikohl	Nicholson/Leon	PA	Truck	35	0.034	2.27	12322	N/A	N/A	27.09
2000	Keystone	Amerikohl	Various	PA	Truck	10	0.052	2.17	12128	N/A	N/A	26.06
2002	Keystone	Canterbury Coal Co	David/DiAnne	PA	Truck	20	0.048	2.14	12343	N/A	N/A	26.27
2003	Keystone	Canterbury Coal Co	David/DiAnne	PA	Truck	20	0.124	2.22	12380	N/A	N/A	26.24
Pennsylvania Power & Light co												
1998	Montour	Power Operating Co	Various	PA	Train	175	0.407	2.15	12478	N/A	N/A	34.61
1999	Brunner Island	Canterbury Coal Co	Various	PA	Train	257	0.302	2.15	12683	N/A	N/A	39.21
1999	Brunner Island	Consol PA Coal Co	Bailey,Enlow Fork	PA	Train	303	0.983	1.66	13143	N/A	N/A	41.70
1999	Brunner Island	Cyprus Emerald Res	Emerald	PA	Train	319	1.379	1.44	13119	N/A	N/A	41.17
1998	Brunner Island	E P Bender Coal Co	Various	PA	Train	179	0.022	2.12	12574	N/A	N/A	36.94
1998	Montour	Canterbury Coal Co	Various	PA	Train	287	0.163	2.15	12628	N/A	N/A	39.12
1999	Montour	Consol PA Coal Co	Bailey,Enlow Fork	PA	Train	382	0.261	1.63	13161	N/A	N/A	42.08
1999	Montour	Cyprus Emerald Res	Emerald	PA	Train	398	0.086	1.35	13337	N/A	N/A	41.21
1999	Montour	E P Bender Coal Co	Various	PA	Train	239	0.645	1.99	12631	N/A	N/A	37.51
1999	Montour	River Hill Coal Co	Various	PA	Train	123	0.330	2.02	12622	N/A	N/A	36.66
N/A	Montour	Lady Jane Collieries	Various	PA	Train	200	0.008	1.75	12231	N/A	N/A	38.86
N/A	Sunbury	Lady Jane Collieries	Various	PA	Train	157	0.294	1.74	12124	N/A	N/A	39.71
Pennsylvania Power co												
2002	Bruce Mansfield	Quaker Coal Co	Nelms, Beverly	OH	Barge	48	0.088	2.62	12114	N/A	N/A	24.71
Philadelphia Electric co												
2000	Cromby	Cyrpus Emeral Res	Deep Mine	PA	Train	371	0.141	1.47	12068	23.36	11.75	35.03
2000	Cromby	United Eastern Coal	84	PA	Train	373	0.245	1.55	13096	25.09	12.54	37.62
2000	Eddystone	Cyrpus Emeral Res	Deep Mine	PA	Train	401	0.391	1.45	13204	25.8	12.9	38.69
2000	Eddystone	United Eastern Coal	84	PA	Train	403	0.744	1.53	13236	25.48	12.74	38.22
Potomac Electric Power co												
1997	Potomac River	Lodestar Energy, Inc	Pax	WV	Train	395	0.113	0.75	13196	N/A	N/A	41.95
1997	Potomac River	Southeast Fuels Inc	Samara	WV	Train	394	0.227	0.76	12894	N/A	N/A	40.89
1998	Chalk Point	Naco Utility Sales	Metbki	MD	Train	272	0.088	1.51	13201	N/A	N/A	47.00
1998	Chalk Point	Southeast Mather	Buffalo	MD	Train	265	0.080	1.49	12973	N/A	N/A	48.94
1998	Chalk Point	Summers Fuel, Inc	Leslie	PA	Train	430	0.153	1.68	12931	N/A	N/A	42.46
1998	Morgantown	Naco Utility Sales	Metbki	MD	Train	272	0.248	1.51	13201	N/A	N/A	47.00
1998	Morgantown	Southeast Mather	Buffalo	MD	Train	265	0.260	1.49	12973	N/A	N/A	48.94
1998	Morgantown	Summers Fuel, Inc	Leslie	PA	Train	430	0.077	1.68	12931	N/A	N/A	42.46
1998	Potomac River	Highlands Coal Sales	Colonial	KY	Train	401	0.148	0.73	12962	N/A	N/A	41.16
1999	Chalk Point	Moore Energy Resourc	Deep Hollow	WV	Train	296	0.061	1.58	13084	N/A	N/A	47.41
1999	Chalk Point	PBS Coal Inc	Shade Creek	PA	Train	360	0.251	1.20	13228	N/A	N/A	43.13
1999	Dickerson	Anker Energy Corp	Sentinel	WV	Train	228	0.372	1.42	13128	N/A	N/A	37.22
1999	Dickerson	Coastal Coal Sales	Deep Hollow	WV	Train	200	0.282	1.55	13045	N/A	N/A	38.66

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Potomac Electric Power Co (continued)												
1999	Dickerson	Patriot Mining Co	Patriot	WV	Train	196	0.341	1.37	12850	N/A	N/A	36.98
1999	Morgantown	Moore Energy Resourc	Deep Hollow	WV	Train	296	0.192	1.58	13084	N/A	N/A	47.41
1999	Morgantown	PBS Coal Inc	Shade Creek	PA	Train	360	0.255	1.20	13228	N/A	N/A	43.13
2003	Potomac River	Southeast Fuels Inc	Glen Alum	WV	Train	394	0.035	0.77	12528	N/A	N/A	40.29
Public Service Co of nh												
1997	Schiller	Consol	Alpine/Bailey	WV	Multimode	663	0.161	1.47	12975	36.49	5.82	42.31
1998	Merrimack	Consol	Loveridge	WV	Train	875	0.066	2.17	13218	21.82	18.32	41.75
1999	Merrimack	Peabody Coal Sales	Federal	WV	Train	875	0.206	2.17	13410	22.14	18.59	41.27
2001	Merrimack	United Eastern	Mine 84	PA	Train	875	0.147	1.41	13259	25.40	17.83	44.59
Public Service of nm												
2017	San Juan	San Juan Basin	San Juan,LaPlata	NM	Truck	26	3.430	0.87	9319	21.19	8.99	30.18
Public Service Co of Colorado												
1997	Arapahoe	Cyprus/Amax Coal Co	Eagle,Foidel	CO	Train	378	0.094	0.47	11263	N/A	N/A	32.50
1997	Cherokee	Cyprus/Amax Coal Co	Eagle,Foidel	CO	Train	363	1.275	0.46	11338	N/A	N/A	27.15
1997	Valmont	Cyprus/Amax Coal Co	Eagle,Foidel	CO	Train	395	0.309	0.47	11317	N/A	N/A	28.99
2000	Arapahoe	Arco Coal Co	West Elk	CO	Train	378	0.004	0.52	11588	N/A	N/A	25.39
2000	Cherokee	Arco Coal Co	West Elk	CO	Train	363	0.664	0.52	11588	N/A	N/A	15.75
2000	Valmont	Arco Coal Co	West Elk	CO	Train	395	0.007	0.52	11588	N/A	N/A	26.47
2014	Comanche	Cyprus/Amax Coal Co	BelleAyr,Eagle Butte	WY	Train	575	2.171	0.25	8608	N/A	N/A	16.67
2014	Pawnee	Cyprus/Amax Coal Co	BelleAyr,Eagle Butte	WY	Train	368	1.782	0.38	8339	N/A	N/A	15.13
Public Service Co of In Inc												
1997	Cayuga	Catlin Coal Co, Inc	Riola	IL	Truck	35	0.239	1.73	10863	N/A	N/A	24.13
1997	Gibson	Consolidation Coal	Rend Lake	IL	Train	60	0.223	1.01	11720	N/A	N/A	1.43
1997	Gibson	Cyprus Amax Mineral	Sycamore	IN	Truck	45	0.128	2.34	10878	N/A	N/A	24.16
1997	Gibson	Cyprus Amax Mineral	Sycamore	IN	Truck	45	0.270	1.46	10958	N/A	N/A	25.91
1997	Gibson	PNR Sales Corp	AMC South Mine	IN	Truck	65	0.059	1.13	11286	N/A	N/A	25.07
1997	R Gallagher	Consolidation Coal	Rend Lake	IL	Multimode	90	0.054	0.98	11918	N/A	N/A	1.33
1997	Wabash River	Solar Sources Inc	Coffie	IN	Truck	24	0.010	0.89	8165	N/A	N/A	11.48
1998	Edwardsport	Triad Mining of IN	Various	IN	Truck	8	0.044	2.39	11085	N/A	N/A	21.01
1998	Wabash River	Little Sandy Coal Co	Pond Creek	IN	Train	64	0.254	1.33	11065	N/A	N/A	25.93
1998	Wabash River	Little Sandy Coal Co	Brimar	IN	Train	64	0.205	1.35	11002	N/A	N/A	26.01
1999	R Gallagher	Cyprus Amax	Cumberland	PA	Barge	383	0.647	2.31	13065	N/A	N/A	27.69
1999	Wabash River	Peabody COALSALES	Hawthorn	IN	Train	35	0.424	2.26	10908	N/A	N/A	21.12
1999	Wabash River	Peabody COALSALES	Hawthorn	IN	Train	35	0.083	1.69	10658	N/A	N/A	23.02
2000	Edwardsport	Eagle Coal Co	Various	IN	Truck	28	0.111	2.75	11207	N/A	N/A	19.87
2000	Gibson	Cyprus Amax Minerals	Wabash	IN	Train	10	0.622	1.44	10970	N/A	N/A	29.73
2000	Gibson	Eagle Coal Cc	Various	IN	Train	14	2.753	2.75	11207	N/A	N/A	19.87
2000	R Gallagher	Eagle Coal Co	Various	IN	Barge	174	0.002	2.75	11207	N/A	N/A	19.87
2001	Cayuga	Peabody Coal Sales	Hawthorn	IN	Train	85	0.296	1.76	10944	N/A	N/A	27.43
2003	Cayuga	Peabody COALSALES	Hawthorn	IN	Train	85	2.122	1.73	10960	N/A	N/A	26.80

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
Public Service Co of IN Inc (continued)												
2003	Gibson	Peabody COALSALES	Hawthorn	IN	Train	73	0.020	2.10	10976	N/A	N/A	26.40
2003	Wabash River	Peabody COALSALES	Hawthorn	IN	Train	35	0.020	1.76	10829	N/A	N/A	23.39
2004	R Gallagher	Peabody Coalsales	Federal	WV	Barge	340	0.201	2.12	13214	N/A	N/A	28.55
2010	Cayuga	Falcon Coal Co	Various	IN	Train	75	0.102	1.13	10818	N/A	N/A	30.42
2010	Gibson	Falcon Coal Co	Various	IN	Train	150	2.715	1.31	10944	N/A	N/A	30.78
2010	Wabash River	Falcon Coal Co	Various	IN	Train	35	0.331	1.11	10774	N/A	N/A	30.30
1998	Merrimack	Cyprus Amax	Emerald	PA	Train	875	0.265	1.36	13208	26.38	18.04	45.76
Public Service Co of Oklahoma												
2014	Northeastern	Kerr-McGee Coal Corp	Various	WY	Train	1,074	1.354	0.45	8469	N/A	N/A	20.71
2014	Northeastern	Kerr-McGee Coal Corp	Various	WY	Train	1,074	1.354	0.24	8877	N/A	N/A	21.71
2014	Northeastern	Kerr-McGee Coal Corp	Various	WY	Train	1,074	1.354	0.20	8793	N/A	N/A	21.50
Sierra Pacific Power co												
2003	North Valmy	Southern Utah Fuel	Sufco	UT	Train	533	0.712	0.34	11272	N/A	N/A	46.47
South Carolina Electric & Gas co												
1999	Cope Station	Kopper Glo Fuel, Inc	Straight Creek Mine	TN	Train	617	0.015	1.52	12938	N/A	N/A	39.60
1999	Canadys Steam	Kopper Glo Fuel, Inc	Straight Creek Mine	TN	Train	617	0.041	1.46	12476	N/A	N/A	41.04
1999	Urquhart	Kopper Glo Fuel, Inc	Straight Creek Mine	TN	Train	617	0.150	1.44	12898	N/A	N/A	39.46
1999	Wateree	Kopper Glo Fuel, Inc	Straight Creek Mine	TN	Train	617	0.156	1.55	12628	N/A	N/A	38.58
1997	Cope Station	Quaker Coal Co	Damron Fork	KY	Train	524	0.009	0.76	12899	N/A	N/A	42.17
1997	Cope Station	Quaker Coal Co Inc	Road Creek	KY	Train	524	0.152	1.42	12785	N/A	N/A	41.17
1997	Canadys Steam	Quaker Coal Co Inc	Road Creek	KY	Train	524	0.027	1.53	12580	N/A	N/A	39.23
1997	Canadys Steam	VA Iron, Coal & Coke	Virginia Iron	KY	Train	524	0.022	0.95	13058	N/A	N/A	43.99
1997	McMeekin	Quaker Coal Co Inc	Road Creek	KY	Train	524	0.009	1.27	13288	N/A	N/A	43.41
1997	McMeekin	VA Iron, Coal & Coke	Virginia Iron	KY	Train	524	0.088	1.14	13084	N/A	N/A	42.93
1997	Urquhart	Quaker Coal Co Inc	Road Creek	KY	Train	524	0.045	1.23	12797	N/A	N/A	42.90
1997	Urquhart	VA Iron, Coal & Coke	Virginia Iron	KY	Train	524	0.007	1.46	13327	N/A	N/A	44.90
1997	Williams	Quaker Coal Co	Damron Fork	KY	Train	524	0.247	0.81	12766	N/A	N/A	42.25
1998	Cope Station	Delta Coals Inc	Red River	VA	Train	524	0.010	1.46	12667	N/A	N/A	39.24
1998	Cope Station	TECO Coal Corp	Elkhorn	KY	Train	561	0.053	1.38	12821	N/A	N/A	39.04
1998	Canadys Steam	Delta Coals Inc	Red River	VA	Train	524	0.018	1.52	12781	N/A	N/A	39.59
1998	Canadys Steam	TECO Coal Corp	Elkhorn	KY	Train	561	0.272	1.51	12872	N/A	N/A	39.77
1998	Urquhart	Delta Coals Inc	Red River	VA	Train	524	0.028	1.55	12777	N/A	N/A	38.93
1998	Urquhart	TECO Coal Corp	Elkhorn	KY	Train	561	0.048	1.48	12932	N/A	N/A	39.56
1998	Urquhart	VA Iron, Coal & Coke	Virginia Iron	VA	Train	406	0.009	0.93	13218	N/A	N/A	40.68
1998	Wateree	Delta Coals Inc	Red River	VA	Train	524	0.151	1.68	12731	N/A	N/A	38.92
1998	Wateree	TECO Coal Corp	Elkhorn	KY	Train	561	0.090	1.05	12635	N/A	N/A	38.75
1998	Wateree	VA Iron, Coal & Coke	Virginia Iron	VA	Train	406	0.346	1.24	12724	N/A	N/A	38.87
1998	Williams	TECO Coal Corp	Elkhorn	KY	Train	561	0.611	0.73	12903	N/A	N/A	41.86
1999	Cope Station	James River Coals	Various	KY	Train	617	0.000	0.81	12700	N/A	N/A	43.69
1999	Cope Station	Vanco Coal Sales	Marilu	KY	Train	617	0.073	0.91	12428	N/A	N/A	37.94

See notes at end of table

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
South Carolina Electric & Gas Co (continued)												
1999	Cope Station	Quaker Coal Co Inc	Road Creek	KY	TRAIN	524	0.257	1.43	12686	N/A	N/A	38.60
1999	Canadys Steam	Quaker Coal Co Inc	Road Creek	KY	TRAIN	524	0.030	1.37	12769	N/A	N/A	39.61
1999	McMeekin	Quaker Coal Co Inc	Road Creek	KY	TRAIN	524	0.034	1.48	12979	N/A	N/A	39.31
1999	Urquhart	Quaker Coal Co Inc	Road Creek	KY	TRAIN	524	0.004	1.06	13755	N/A	N/A	42.95
1999	Wateree	Mapco Coal Sales	Martiki	KY	TRAIN	617	0.152	0.97	12412	N/A	N/A	37.72
1999	Wateree	Quaker Coal Co Inc	Road Creek	KY	TRAIN	524	0.052	1.23	12652	N/A	N/A	38.42
1999	Williams	James River Coals	Various	KY	TRAIN	617	0.345	0.80	12800	N/A	N/A	42.96
2000	Cope Station	Quaker Coal Co	Damron Fork	KY	TRAIN	524	0.036	1.27	13253	N/A	N/A	40.41
2000	Cope Station	VA Iron, Coal & Coke	Virginia Iron	KY	TRAIN	433	0.034	1.35	13260	N/A	N/A	40.51
2000	McMeekin	VA Iron, Coal & Coke	Virginia Iron	KY	TRAIN	433	0.299	1.47	13221	N/A	N/A	40.42
2000	Urquhart	VA Iron, Coal & Coke	Virginia Iron	KY	TRAIN	433	0.030	1.35	13389	N/A	N/A	42.51
2000	Wateree	VA Iron, Coal & Coke	Virginia Iron	KY	TRAIN	433	0.009	1.60	13016	N/A	N/A	40.40
2000	Williams	Quaker Coal Co	Damron Fork	KY	TRAIN	524	0.209	0.77	12933	N/A	N/A	42.49
Southern California Edison Co												
2005	Mohave	Peabody Coal Co	Black Mesa	AZ	PIPELINE	273	4.397	0.51	12250	27.21	6.25	33.45
Southern Indiana Gas & Electric Co												
1997	F B Culley	United Minerals Inc	Deer Ridge	IN	TRUCK	32	0.259	6.59	11342	17.04	2.91	19.95
Southwestern Electric Power Co												
2006	Flint Creek	Amax Coal West Inc	BelleAyr/Eagle Butte	WY	TRAIN	1,035	1.293	0.35	8381	N/A	N/A	27.50
2006	Welsh	Amax Coal West Inc	BelleAyr/Eagle Butte	WY	TRAIN	1,454	4.992	0.35	8380	N/A	N/A	28.66
Southwestern Public Service Co												
1998	Harrington Station	Caballo Coal	Caballo	WY	TRAIN	911	1.272	0.36	8512	N/A	N/A	17.47
2016	Harrington Station	Tuco	Black Thunder	WY	TRAIN	901	3.000	0.36	8700	N/A	N/A	11.42
2017	Tolk Station	Tuco	Black Thunder	WY	TRAIN	1,015	3.941	0.35	8654	N/A	N/A	30.93
Tampa Electric Co												
1997	Big Bend	Centennial Resources	Henderson	KY	BARGE	1,664	0.147	2.68	11102	N/A	N/A	28.49
1997	Big Bend	Costain Coal	Smith & Baker	KY	BARGE	1,594	0.119	3.01	12119	N/A	N/A	32.33
1997	Big Bend	Sugar Camp Coal	Eagle Valley	IL	BARGE	1,602	0.397	2.68	12707	N/A	N/A	32.09
1998	Big Bend	Peabody Coalsales Co	Patriot	KY	BARGE	1,602	0.198	2.51	11140	N/A	N/A	29.92
1999	Big Bend	Jader Fuel Co, Inc	Garden Valley	IL	BARGE	1,602	0.540	3.00	12888	N/A	N/A	33.67
1999	Big Bend	Kerr McGee Coal	Galatia	KY	BARGE	1,519	0.942	1.19	11984	N/A	N/A	34.66
1999	Big Bend	Peabody Coalsales Co	Patriot Mine	KY	BARGE	1,602	0.526	2.65	11428	N/A	N/A	30.63
1999	Gannon	Gatliff Coal Co	Various	KY	TRAIN	850	0.961	1.23	12776	N/A	N/A	63.79
1999	Gannon	Gatliff Coal Co	Various	KY	MULTIMODE	2,102	0.043	1.23	12776	N/A	N/A	56.97
2004	Big Bend	Peabody Coal Co	Big Ridge, Wheatcroft	KY	BARGE	1,482	0.238	1.92	12293	N/A	N/A	42.87
Toledo Edison Co-Centerior Energy												
1998	Bay Shore	Cyprus Coal	Emerald/ Belle Ayr	WY	TRAIN	1,600	0.411	0.54	8581	N/A	N/A	21.53
Tri-State G & T Assn Inc												
2017	Craig	ColoWyo Coal Co	ColoWyo Coal	CO	TRAIN	24	0.089	0.34	10352	N/A	N/A	21.73

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
[illegible]												
United Illuminating Co												
2007	Bridgeport Harbor	Pittston Coal Sales	Various	KY	Multimode	790	0.851	0.53	13132	N/A	N/A	51.35
[illegible]												
Virginia Electric & Power co												
1997	Bremo Bluff	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	402	0.349	0.90	11724	N/A	N/A	33.45
1997	Bremo Bluff	Consol Inc	Jones Fork,Mill Crk	KY	Train	501	0.026	1.20	12600	N/A	N/A	39.80
1997	Bremo Bluff	Premier Elkhorn Coal	Premier Elkhorn	KY	Train	538	0.043	1.06	12500	N/A	N/A	40.51
1997	Chesapeake	Pardee Coal Co Inc	Red River	VA	Train	458	0.117	1.42	12966	N/A	N/A	37.52
1997	Chesterfield	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	484	0.323	0.90	12141	N/A	N/A	35.38
1997	Chesterfield	Ashland Coal Co Inc	Powells Creek	KY	Train	580	0.205	1.10	12500	N/A	N/A	39.49
1997	Chesterfield	Consol Inc	Jones Fork,Mill Crk	KY	Train	583	0.392	1.13	12600	N/A	N/A	39.03
1997	Chesterfield	Eastern Assoc Coal	Rocklick	WV	Train	503	0.239	1.00	13000	N/A	N/A	41.33
1997	Chesterfield	Franklin Coal Sales	Pike County	KY	Train	583	0.331	1.00	12500	N/A	N/A	37.19
1997	Chesterfield	Premier Elkhorn Coal	Premier Elkhorn	KY	Train	620	0.175	1.03	12500	N/A	N/A	40.00
1997	Clover	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	602	0.030	0.88	12100	N/A	N/A	34.03
1997	Clover	Coastal Coal Sales	Tom's Creek	KY	Train	352	0.446	1.12	12574	N/A	N/A	36.13
1997	Clover	Coastal Coal Sales.	Tom's Creek	VA	Train	352	0.235	1.12	12574	N/A	N/A	36.13
1997	Clover	Pardee Coal Co Inc	Red River	VA	Train	388	0.101	1.16	13000	N/A	N/A	39.74
1997	Possum Point	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	553	0.206	0.90	11709	N/A	N/A	33.65
1997	Possum Point	Eastern Assoc Coal	Rocklick	WV	Train	572	0.174	0.96	12975	N/A	N/A	41.52
1997	Possum Point	Premier Elkhorn Coal	Premier Elkhorn	KY	Train	689	0.012	1.00	12500	N/A	N/A	40.25
1997	Yorktown	Premier Elkhorn Coal	Premier Elkhorn	KY	Train	673	0.127	1.02	12500	N/A	N/A	40.25
1998	Bremo Bluff	AMVEST Coal Sales	Fola	WV	Train	311	0.029	0.80	12500	N/A	N/A	35.94
1998	Chesapeake	Arch Coal Sales Co	Pardee complex	VA	Train	458	0.211	1.00	12500	N/A	N/A	35.67
1998	Chesterfield	AMVEST Coal Sales	Fola	WV	Train	393	0.021	0.80	12500	N/A	N/A	36.68
1998	Clover	Arch Coal Sales Co	Pardee complex	VA	Train	388	0.214	0.90	12500	N/A	N/A	36.17
1998	Possum Point	AMVEST Coal Sales	Fola	WV	Train	462	0.105	0.80	12500	N/A	N/A	37.19
1998	Yorktown	AMVEST Coal Sales	Fola	WV	Train	446	0.018	0.80	12500	N/A	N/A	37.45
1999	Bremo Bluff	Pardee Coal Co Inc	Red River	VA	Train	426	0.007	1.50	12500	N/A	N/A	43.31
1999	Chesapeake	Alliance Coal	Roaring Fork	VA	Train	465	0.156	1.20	12800	N/A	N/A	36.52
1999	Chesapeake	Pardee Coal Co Inc	Red River	VA	Train	458	0.232	1.42	12966	N/A	N/A	37.52
1999	Chesapeake	Patriot Fuels Inc	Ambrose Branch	VA	Train	459	0.152	1.09	12996	N/A	N/A	37.61
1999	Chesapeake	Smoky Mtn Coal Corp	Cane Patch	VA	Train	461	0.310	0.96	12800	N/A	N/A	36.78
1999	Chesterfield	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	484	0.249	0.89	12100	N/A	N/A	35.02
1999	Clover	Alliance Coal	Roaring Fork	VA	Train	332	0.115	1.03	12800	N/A	N/A	37.83
1999	Clover	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	602	0.020	0.88	12100	N/A	N/A	34.03
1999	Clover	Coastal Coal Sales.	Tom's Creek	VA	Train	352	0.343	1.12	12574	N/A	N/A	37.16
1999	Clover	Patriot Fuels Inc	Ambrose Branch	VA	Train	376	0.046	1.10	13000	N/A	N/A	38.68
1999	Clover	Smoky Mtn Coal Corp	Cane Patch	VA	Train	328	0.066	0.94	12800	N/A	N/A	38.09
1999	Possum Point	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	553	0.053	0.89	11891	N/A	N/A	34.65
1999	Yorktown	Arch Coal Sales Co	Dal-Tex, Hobet 21	WV	Train	537	0.085	0.90	12100	N/A	N/A	35.76
2001	Mt Storm	Buffalo Coal Co	Mine #6	WV	Train	19	0.395	1.58	12261	N/A	N/A	30.04

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price* (1996 Dollars)
West Penn Power Co												
1998	Armstrong	Stanford Coal Co	Doverspike	PA	Train	31	0.256	1.30	12478	25.37	3.59	28.96
1998	Mitchell	Consolidation Coal	Various	WV	Barge	70	0.044	3.13	12302	34.82	1.55	36.10
1998	Mitchell	Consolidation Coal	Various	WV	Barge	70	0.056	2.31	12358	35.01	1.55	36.29
1998	Mitchell	Consolidation Coal	Various	WV	Barge	70	0.511	3.38	12188	34.30	1.53	31.77
2001	Hatfields Ferry	Consolidation Coal	Humphrey,Blacksville	WV	Barge	20	3.467	2.08	12861	36.07	0.73	36.77
West Texas Utilities co												
1997	Oklaunion	Triton Coal Company	Buckskin	WY	Train	1,118	1.904	0.43	8469	N/A	N/A	26.49
Wisconsin Electric Power co												
1997	Oak Creek	Amvest	Fola	WV	Train	–	0.024	0.66	12451	N/A	N/A	36.41
1997	Oak Creek	Arco Coal	West Elk	CO	Train	1,530	0.151	0.53	11570	N/A	N/A	31.34
1997	Oak Creek	Consol	Rend Lake	IL	Train	367	0.022	0.98	12582	N/A	N/A	35.87
1997	Oak Creek	Consol	Jones Fork	KY	Train	–	0.023	0.56	11802	N/A	N/A	32.74
1997	Oak Creek	Cyprus Amax	Emerald	PA	Train	634	0.018	1.16	13293	N/A	N/A	38.77
1997	Oak Creek	Oxbow	Sanborn Creek	CO	Train	1,530	0.062	0.56	12269	N/A	N/A	32.88
1997	Oak Creek	United Eastern	Mine 84	PA	Train	588	0.274	1.36	13273	N/A	N/A	36.84
1997	Port Washington	Consol	Bailey	PA	Multimode	–	0.154	4.45	13170	N/A	N/A	39.72
1997	Port Washington	Drummond	West Elk	CO	Multimode	–	0.108	0.51	11510	N/A	N/A	27.52
1997	Port Washington	United Eastern	Mine 84	PA	Multimode	–	0.461	1.36	13276	N/A	N/A	37.64
1997	Port Washington	United Eastern	Mine 84	PA	Multimode	–	0.450	1.36	13276	N/A	N/A	37.64
1997	Presque Isle	Detroit Edison	Decker	MT	Multimode	–	0.500	0.75	9485	N/A	N/A	36.96
1997	Presque Isle	Drummond	West Elk	CO	Multimode	–	0.099	0.51	4,510	N/A	N/A	29.98
1997	Presque Isle	Kennecott	Ant/Spring	WY	Multimode	–	0.069	0.28	9033	N/A	N/A	19.66
1997	Presque Isle	Westmoreland Resour	Absaloka	MT	Multimode	–	0.354	0.62	8746	N/A	N/A	21.62
1997	Valley	Consol	Bailey	PA	Multimode	–	0.424	1.60	13138	N/A	N/A	40.43
1997	Valley	Consol	Various	PA	Multimode	–	0.196	1.95	13266	N/A	N/A	40.12
1997	Valley	Consol	Various	PA	Multimode	–	0.010	2.15	13182	N/A	N/A	39.14
1999	Oak Creek	Consol	Bailey	PA	Train	635	0.636	1.61	13140	N/A	N/A	37.62
1999	Oak Creek	Kennecott	Antelope	WY	Train	1,190	0.685	0.21	8766	N/A	N/A	16.26
1999	Presque Isle	Oxbow Carbon & Min	Sanborn Creek	CO	Multimode	–	0.469	0.61	12275	N/A	N/A	33.57
2002	Pleasant Prairie	Arco Coal	Coal Creek	WY	Train	1,190	0.972	0.35	8363	N/A	N/A	13.31
2005	Pleasant Prairie	Caballo Rojo	Caballo Rojo	WY	Train	1,190	2.436	0.33	8449	N/A	N/A	12.97
2006	Pleasant Prairie	Peabody	Caballo	WY	Train	1,190	1.955	0.36	8520	N/A	N/A	13.39
Wisconsin Power & Light co												
1997	Edgewater	Tanoma Coal Sales	Bear Canyon	UT	Train	1,272	0.072	0.55	12306	N/A	N/A	40.75
1997	Rock River	Cyprus AMAX Coal	Belle Ayre	WY	Train	1,134	0.022	0.26	8544	N/A	N/A	19.82
1998	Columbia	Peabody Coal Co	Big Sky	MT	Train	1,043	1.355	0.74	8815	N/A	N/A	16.92
1998	Columbia	Peabody Coal Co	Caballo	WY	Train	1,400	3.631	0.36	8520	N/A	N/A	15.44
1998	Rock River	Consol Coal Co	Rend Lake	IL	Train	–	0.019	0.94	12244	N/A	N/A	40.95
2000	Edgewater	ARCO Thunder Basin	Black Thunder	WY	Train	1,022	0.449	0.33	8780	N/A	N/A	19.57

See notes at end of table

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Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant

Utility Name Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	Btus (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price[a] (1996 Dollars)
Wisconsin Power & Light Co (continued)												
2000	Edgewater	ARCO Thunder Basin	Black Thunder	WY	Train	1,400	0.449	0.33	8780	N/A	N/A	19.67
2001	Nelson Dewey	Kennecott Energy Co	Spring Creek	MT	Multimode	1,136	0.456	0.36	9381	N/A	N/A	22.83
2001	Rock River	Kennecott Energy Co	Spring Creek	MT	Train	1,098	0.288	0.36	9413	N/A	N/A	22.56
2002	Edgewater	Arco Coal Co	Coal Creek	WY	Train	1,412	1.012	0.37	8313	N/A	N/A	20.70
Wisconsin Public Service Corp												
1998	Pulliam	Powder River Coal Co	North Antelope	WY	Train	—	1.352	0.47	8848	N/A	N/A	16.88
1998	Weston	Powder River Coal Co	North Antelope	WY	Train	—	1.096	0.50	8856	N/A	N/A	17.56
2018	Weston	Arco Coal Sales	Black Thunder	WY	Train	—	0.829	0.35	8777	N/A	N/A	23.58

"—" = Data not available.

[a]The sum of the mine price and transportation cost may not equal the delivered price because the transportation cost and the mine price provided by respondents on the FERC Form 580 are weighted average costs based on the yearly total coal tonnage and Btu of coal purchased.

NA = Not available.

Source: Federal Energy Regulatory Commission, FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices."

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DOE024-1113

Appendix C

Contract Coal Transportation Rates in Nominal Dollars

Appendix C

Contract Coal Transportation Rates in Nominal Dollars

Coal transportation rates are presented in nominal dollars in this appendix. Tables C1 through C9 present, in nominal dollars, the contract coal transportation rates by rail that were presented in Chapter 3 in real 1996 dollars.

The gross domestic product deflators used to convert the nominal-dollar rates to real 1996 dollar rates in the body of the text are as follows:

1988	0.80215	**1993**	0.94053
1989	0.83271	**1994**	0.96006
1990	0.86527	**1995**	0.98103
1991	0.89661	**1996**	1.00000
1992	0.91846	**1997**	1.01947

Table C1. Average Rate per Ton for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997
(Nominal Dollars)

Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	11.68	15.09	11.04	8.54	5.27
1989	11.62	14.96	11.61	6.68	5.11
1990	11.89	15.15	12.02	8.11	5.31
1991	10.99	13.92	10.38	8.06	5.17
1992	10.91	14.23	9.88	6.97	4.92
1993	11.21	13.50	10.03	7.40	4.85
1994	10.53	12.86	9.11	5.90	5.30
1995	10.92	12.68	9.56	5.17	6.19
1996	10.96	12.32	9.76	7.50	6.47
1997	11.02	12.29	9.59	8.59	5.95

Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000.

Source: Energy Information Administration, Coal Transportation Rate Database.

Table C2. Average Rate per Million Btu for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997
(Cents per Million Btu in Nominal Dollars)

Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	58.5	81.7	48.0	39.0	22.7
1989	58.9	82.1	50.5	30.5	22.1
1990	63.1	83.2	65.0	34.8	22.5
1991	54.7	76.0	44.9	34.6	21.8
1992	54.8	77.4	42.2	30.6	20.9
1993	57.5	74.4	43.3	32.5	20.4
1994	53.6	70.3	38.8	26.5	22.2
1995	56.0	69.7	40.4	23.5	25.8
1996	56.3	68.3	40.9	29.8	26.8
1997	57.1	68.3	40.7	33.7	24.8

Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000.

Source: Energy Information Administration, Coal Transportation Rate Database.

Table C3. Average Rate per Ton-Mile for Contract Coal Shipments by Rail, by Sulfur Category, 1988-1997
(Mills per Ton-Mile in Nominal Dollars)

Year	All Coal	Low Sulfur	Medium Sulfur A	Medium Sulfur B	High Sulfur
1988	18.6	15.4	24.8	36.7	40.9
1989	18.0	15.0	25.4	33.0	40.2
1990	18.9	15.8	24.2	31.6	35.2
1991	18.2	14.8	24.7	32.8	35.9
1992	17.5	14.4	25.2	35.7	33.1
1993	15.9	13.4	24.0	37.9	34.8
1994	15.4	13.1	22.3	33.3	30.5
1995	15.1	12.9	22.9	41.5	31.1
1996	14.8	12.5	23.6	32.1	33.4
1997	13.9	11.8	22.9	34.2	33.0

Notes: Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets SO_2 emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000.

Source: Energy Information Administration, Coal Transportation Rate Database.

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Table C4. Average Rate per Ton for Contract Coal Shipments by Rail, by Demand Region, 1988-1997
(Nominal and 1996 Dollars)

Demand Region	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
East North Central										
Nominal Dollars ...	9.66	9.58	8.76	9.31	9.36	9.61	8.84	9.94	9.58	9.62
1996 Dollars	12.05	11.50	10.13	10.38	10.19	10.21	9.21	10.13	9.58	9.44
East South Central										
Nominal Dollars ...	5.33	5.31	5.84	5.73	5.35	5.39	6.72	7.46	7.89	8.57
1996 Dollars	6.64	6.37	6.75	6.39	5.83	5.73	7.00	7.60	7.89	8.41
Mid Atlantic										
Nominal Dollars ...	13.96	13.72	10.86	11.62	10.18	10.21	12.41	13.20	11.63	11.85
1996 Dollars	17.41	16.47	12.56	12.95	11.09	10.85	12.93	13.46	11.63	11.63
Mountain										
Nominal Dollars ...	9.41	8.88	7.82	7.29	6.89	6.97	6.51	6.64	7.74	7.31
1996 Dollars	11.73	10.66	9.04	8.12	7.51	7.40	6.78	6.77	7.74	7.18
New England										
Nominal Dollars ...	17.64	17.67	18.53	18.42	18.10	18.39	14.15	18.45	18.10	18.49
1996 Dollars	22.00	21.21	21.42	20.53	19.71	19.55	14.74	18.81	18.10	18.14
Pacific										
Nominal Dollars ...	16.63	—	—	—	—	—	15.22	14.94	14.20	15.40
1996 Dollars	20.74	—	—	—	—	—	15.86	15.23	14.20	15.11
South Atlantic										
Nominal Dollars ...	11.00	10.78	11.01	11.33	11.05	11.49	9.37	9.62	10.89	11.51
1996 Dollars	13.71	12.95	12.73	12.63	12.04	12.21	9.76	9.80	10.89	11.29
West North Central										
Nominal Dollars ...	11.11	11.16	10.68	10.43	10.50	10.50	10.00	9.74	10.07	9.92
1996 Dollars	13.86	13.39	12.35	11.62	11.44	11.16	10.42	9.92	10.07	9.73
West South Central										
Nominal Dollars ...	19.20	18.65	19.81	16.56	17.39	17.04	18.51	17.68	16.10	15.69
1996 Dollars	23.94	22.39	22.90	18.46	18.94	18.11	19.29	18.02	16.10	15.40
U.S. Average										
Nominal Dollars ...	11.68	11.62	11.89	10.99	10.91	11.21	10.53	10.92	10.96	11.02
1996 Dollars	14.56	13.95	13.75	12.25	11.89	11.91	10.97	11.13	10.96	10.82

— = Not applicable
Source: Energy Information Administration, Coal Transportation Rate Database.

23711

DOE024-1117

Table C5. Average Rate per Million Btu for Contract Coal Shipments by Rail, by Demand Region, 1988-1997
(Cents per Million Btu in Nominal and 1996 Dollars)

Demand Region	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
East North Central										
Nominal Dollars .	46.2	46.0	42.5	45.2	45.2	47.9	45.0	51.8	50.5	51.3
1996 Dollars	57.6	55.2	49.1	50.4	49.2	50.9	46.9	52.8	50.5	50.3
East South Central										
Nominal Dollars .	21.8	22.0	23.9	23.2	21.8	22.0	28.8	32.0	37.0	41.4
1996 Dollars	27.2	26.5	27.6	25.8	23.7	23.4	30.0	32.6	37.0	40.6
Mid Atlantic										
Nominal Dollars .	53.3	52.5	42.2	45.0	39.5	39.7	47.6	50.8	44.9	45.5
1996 Dollars	66.5	63.1	48.8	50.1	43.0	42.2	49.6	51.7	44.9	44.6
Mountain										
Nominal Dollars .	47.0	44.7	39.5	37.4	35.6	36.3	33.5	34.2	39.2	37.7
1996 Dollars	58.6	53.6	45.7	41.7	38.8	38.6	34.9	34.8	39.2	36.9
New England										
Nominal Dollars .	66.0	66.0	69.7	69.5	68.1	69.7	53.6	69.9	68.5	69.9
1996 Dollars	82.3	79.3	80.6	77.5	74.2	74.1	55.8	71.3	68.5	68.5
Pacific										
Nominal Dollars .	98.6	–	–	–	–	–	81.2	80.5	80.0	86.0
1996 Dollars	122.9	–	–	–	–	–	55.9	82.0	80.0	84.3
South Atlantic										
Nominal Dollars .	43.8	43.2	44.1	45.2	43.7	45.4	37.1	37.9	43.3	48.8
1996 Dollars	54.6	51.9	50.9	50.4	47.6	48.2	33.8	38.7	43.3	47.9
West North Central										
Nominal Dollars .	64.8	65.6	61.3	59.7	60.0	60.7	57.3	55.7	57.5	56.8
1996 Dollars	80.8	78.7	70.8	66.6	65.4	64.5	59.7	56.8	57.5	55.7
West South Central										
Nominal Dollars .	110.1	107.6	126.0	95.1	99.7	98.2	107.2	102.4	94.0	91.2
1996 Dollars	137.2	129.2	145.6	106.0	108.5	104.4	111.6	104.4	94.0	89.4
U.S. Average										
Nominal Dollars .	58.5	58.9	63.1	54.7	54.8	57.5	53.6	56.0	56.3	57.1
1996 Dollars	72.9	70.8	72.9	61.0	59.7	61.1	55.8	57.1	56.3	56.0

– = Not applicable.
Source: Energy Information Administration, Coal Transportation Rate Database.

23712

DOE024-1118

Table C6. Average Rate per Ton-Mile for Contract Coal Shipments by Rail, by Demand Region, 1988-1997
(Mills per Ton-Mile in Nominal and 1996 Dollars)

Demand Region	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
East North Central										
Nominal Dollars	21.3	20.9	19.6	18.4	18.1	14.6	12.7	13.0	12.3	11.5
1996 Dollars	26.5	25.1	22.7	20.5	19.7	15.6	13.2	13.2	12.3	11.3
East South Central										
Nominal Dollars	27.4	28.4	29.7	30.4	25.9	26.0	19.1	20.0	15.4	14.4
1996 Dollars	34.2	34.1	34.3	33.9	28.2	27.6	19.9	20.4	15.4	14.2
Mid Atlantic										
Nominal Dollars	32.3	32.6	35.4	36.2	36.8	36.6	33.4	33.9	35.4	35.0
1996 Dollars	40.3	39.1	40.9	40.4	40.0	38.9	34.8	34.6	35.4	34.3
Mountain										
Nominal Dollars	26.1	27.4	28.2	27.8	28.8	27.2	27.4	26.9	24.4	23.4
1996 Dollars	32.6	32.9	32.6	31.0	31.3	28.9	28.5	27.4	24.4	22.9
New England										
Nominal Dollars	20.2	20.2	22.0	21.9	21.3	21.6	16.7	20.9	20.6	21.2
1996 Dollars	25.1	24.2	25.5	24.4	23.2	22.9	17.4	21.3	20.6	20.8
Pacific										
Nominal Dollars	15.2	—	—	—	—	—	12.2	11.7	10.4	11.3
1996 Dollars	19.0	—	—	—	—	—	12.7	11.9	10.4	11.1
South Atlantic										
Nominal Dollars	31.1	32.0	27.7	28.9	27.7	27.8	22.7	22.9	24.7	20.4
1996 Dollars	38.8	38.4	32.0	32.2	30.2	29.5	23.6	23.3	24.7	20.0
West North Central										
Nominal Dollars	15.2	14.8	15.8	15.4	14.7	13.2	13.1	12.5	12.4	12.3
1996 Dollars	19.0	17.8	18.2	17.2	16.1	14.0	13.7	12.8	12.4	12.0
West South Central										
Nominal Dollars	13.6	13.3	14.8	13.1	13.2	12.9	13.5	13.2	12.5	12.0
1996 Dollars	17.0	15.9	17.1	14.6	14.3	13.7	14.1	13.4	12.5	11.7
U.S. Average										
Nominal Dollars	18.6	18.0	18.9	18.2	17.5	15.9	15.4	15.1	14.8	13.9
1996 Dollars	23.2	21.6	21.9	20.3	19.0	16.9	15.0	15.4	14.8	13.6

— = Not applicable
Source: Energy Information Administration, Coal Transportation Rate Database.

Table C7. Average Rate per Ton for Contract Coal Shipments by Rail, by Supply Region, 1988-1997
(Nominal and 1996 Dollars)

Supply Region	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Central Appalachia										
Nominal Dollars	12.06	11.94	11.42	11.72	11.25	11.33	9.60	9.79	10.51	10.11
1996 Dollars	15.03	14.33	13.20	13.07	12.25	12.04	10.00	9.98	10.51	9.92
Illinois Basin										
Nominal Dollars	3.89	3.68	4.18	4.02	3.92	3.69	3.67	4.49	4.05	4.11
1996 Dollars	4.86	4.42	4.84	4.48	4.27	3.93	3.82	4.58	4.05	4.04
North Dakota Lignite										
Nominal Dollars	8.00	7.90	6.94	6.67	6.67	6.62	5.13	4.90	2.26	2.29
1996 Dollars	9.98	9.48	8.02	7.44	7.27	7.03	5.34	4.99	2.26	2.24
Northern Appalachia										
Nominal Dollars	9.42	9.20	9.97	10.38	9.14	9.51	10.01	10.64	10.95	11.34
1996 Dollars	11.75	11.05	11.53	11.57	9.95	10.11	10.43	10.85	10.95	11.13
Other Western Interior										
Nominal Dollars	2.45	7.40	6.47	7.61	7.98	8.16	11.12	7.23	9.54	—
1996 Dollars	3.05	8.88	7.48	8.48	8.69	8.67	11.58	7.37	9.54	—
Powder River Basin										
Nominal Dollars	15.54	15.54	16.21	13.98	14.25	13.55	13.18	13.08	12.66	12.80
1996 Dollars	19.38	18.65	18.73	15.59	15.52	14.40	13.73	13.34	12.66	12.56
Rockies										
Nominal Dollars	14.80	13.77	13.19	13.12	14.36	13.45	14.65	14.25	13.10	12.21
1996 Dollars	18.45	16.53	15.25	14.63	15.64	14.29	15.26	14.52	13.10	11.98
Southern Appalachia										
Nominal Dollars	5.27	4.57	5.14	4.71	4.91	4.96	4.03	6.57	3.77	4.25
1996 Dollars	6.58	5.49	5.95	5.25	5.35	5.27	4.20	6.70	3.77	4.17
Southwest										
Nominal Dollars	7.41	6.43	6.48	6.40	6.67	7.05	6.89	6.91	6.83	7.13
1996 Dollars	9.24	7.72	7.49	7.14	7.27	7.49	7.18	7.04	6.83	7.00
U.S. Average										
Nominal Dollars	11.68	11.62	11.89	10.99	10.91	11.21	10.53	10.92	10.96	11.02
1996 Dollars	14.56	13.95	13.75	12.25	11.89	11.91	10.97	11.13	10.96	10.82

— = Not applicable
Source: Energy Information Administration, Coal Transportation Rate Database.

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Table C8. Average Rate per Million Btu for Contract Coal Shipments by Rail, by Supply Region, 1988-1997
(Cents per Million Btu in Nominal and 1996 Dollars)

Supply Region	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Central Appalachia										
Nominal Dollars	47.3	47.2	46.6	47.8	44.5	44.8	38.2	38.8	41.9	40.6
1996 Dollars	59.0	56.7	53.8	53.3	48.4	47.6	39.8	39.5	41.9	39.8
Illinois Basin										
Nominal Dollars	17.4	16.5	18.5	17.7	17.3	16.2	16.2	19.7	18.0	18.4
1996 Dollars	21.7	19.8	21.4	19.7	18.8	17.2	16.9	20.1	18.0	18.1
North Dakota Lignite										
Nominal Dollars	64.1	63.6	56.0	54.1	54.6	53.8	41.5	39.3	16.3	16.8
1996 Dollars	79.9	76.3	64.7	60.3	59.5	57.2	43.2	40.1	16.3	16.5
Northern Appalachia										
Nominal Dollars	37.7	36.8	39.0	40.0	35.5	37.0	38.5	40.8	42.2	43.5
1996 Dollars	47.1	44.1	45.0	44.6	38.7	39.4	40.1	41.6	42.2	42.6
Other Western Interior										
Nominal Dollars	10.0	31.6	27.5	31.8	33.3	34.7	47.4	30.9	41.2	–
1996 Dollars	12.5	37.9	31.8	35.5	36.3	36.9	49.4	31.5	41.2	–
Powder River Basin										
Nominal Dollars	88.9	89.3	99.5	80.3	81.6	77.9	75.7	75.5	73.1	73.7
1996 Dollars	110.9	107.2	115.0	89.6	88.8	82.8	78.9	77.0	73.1	72.3
Rockies										
Nominal Dollars	66.0	61.4	58.7	57.9	63.3	60.3	65.0	62.8	56.9	52.9
1996 Dollars	82.2	73.8	67.8	64.5	69.0	64.2	67.7	64.0	56.9	51.9
Southern Appalachia										
Nominal Dollars	21.4	18.8	20.7	19.1	19.9	20.6	16.4	25.8	15.1	17.0
1996 Dollars	26.7	22.5	23.9	21.3	21.6	21.9	17.1	26.3	15.1	16.7
Southwest										
Nominal Dollars	36.0	32.5	33.5	33.4	33.5	34.9	35.3	35.6	34.2	36.3
1996 Dollars	44.9	39.0	38.7	37.2	36.5	37.1	36.7	36.3	34.2	35.6
U.S. Average										
Nominal Dollars	58.5	58.9	63.1	54.7	54.8	57.5	53.6	56.0	56.3	57.1
1996 Dollars	72.9	70.8	72.9	61.0	59.7	61.1	55.8	57.1	56.3	56.0

– = Not applicable
Source: Energy Information Administration, Coal Transportation Rate Database.

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Table C9. Average Rate per Ton-Mile for Contract Coal Rail Shipments by Rail, by Supply Region, 1988-1997
(Mills per Ton-Mile in Nominal and 1996-Dollars)

Supply Region	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Central Appalachia										
Nominal Dollars	27.1	28.6	27.0	27.5	25.8	25.8	22.7	22.9	24.7	24.14
1996 Dollars	33.8	34.3	31.2	30.7	28.1	27.4	23.7	23.3	24.7	23.6
Illinois Basin										
Nominal Dollars	36.0	35.9	36.3	36.0	34.2	39.1	33.4	36.2	40.1	33.7
1996 Dollars	44.9	43.1	42.0	40.1	37.3	41.5	34.8	36.9	40.1	33.1
North Dakota Lignite										
Nominal Dollars	26.4	26.6	23.1	21.9	21.7	21.9	22.5	24.2	61.1	62.9
1996 Dollars	32.9	31.9	26.8	24.4	23.6	23.2	23.5	24.7	61.1	61.8
Northern Appalachia										
Nominal Dollars	41.8	39.6	33.1	34.2	34.0	34.4	30.7	32.5	31.9	32.8
1996 Dollars	52.1	47.5	38.3	38.1	37.0	36.5	32.0	33.1	31.9	32.2
Other Western Interior										
Nominal Dollars	98.0	45.4	37.0	38.1	39.9	40.8	54.2	33.8	53.0	—
1996 Dollars	122.2	54.5	42.8	42.4	43.5	43.4	56.4	34.5	53.0	—
Powder River Basin										
Nominal Dollars	14.4	14.1	14.7	13.5	13.6	12.6	12.3	12.1	11.7	11.2
1996 Dollars	18.0	16.9	17.0	15.0	14.8	13.4	12.8	12.4	11.7	11.0
Rockies										
Nominal Dollars	21.5	21.5	20.8	20.9	19.5	18.2	15.7	14.9	15.5	12.8
1996 Dollars	26.8	25.8	24.0	23.2	21.2	19.4	16.4	15.2	15.5	12.6
Southern Appalachia										
Nominal Dollars	36.6	32.6	32.1	34.5	34.6	31.6	43.4	30.6	54.4	41.8
1996 Dollars	45.6	39.1	37.1	38.5	37.7	33.5	45.2	31.2	54.4	41.0
Southwest										
Nominal Dollars	35.2	45.7	51.3	48.6	30.8	25.4	37.3	35.8	36.0	31.9
1996 Dollars	43.9	54.8	59.3	54.2	33.6	27.0	38.8	36.5	36.0	31.3
U.S. Average										
Nominal Dollars	18.6	18.0	18.9	18.2	17.5	15.9	15.4	15.1	14.8	13.9
1996 Dollars	23.2	21.6	21.9	20.3	19.0	16.9	16.0	15.4	14.8	13.6

— = Not applicable
Source: Energy Information Administration, Coal Transportation Rate Database.

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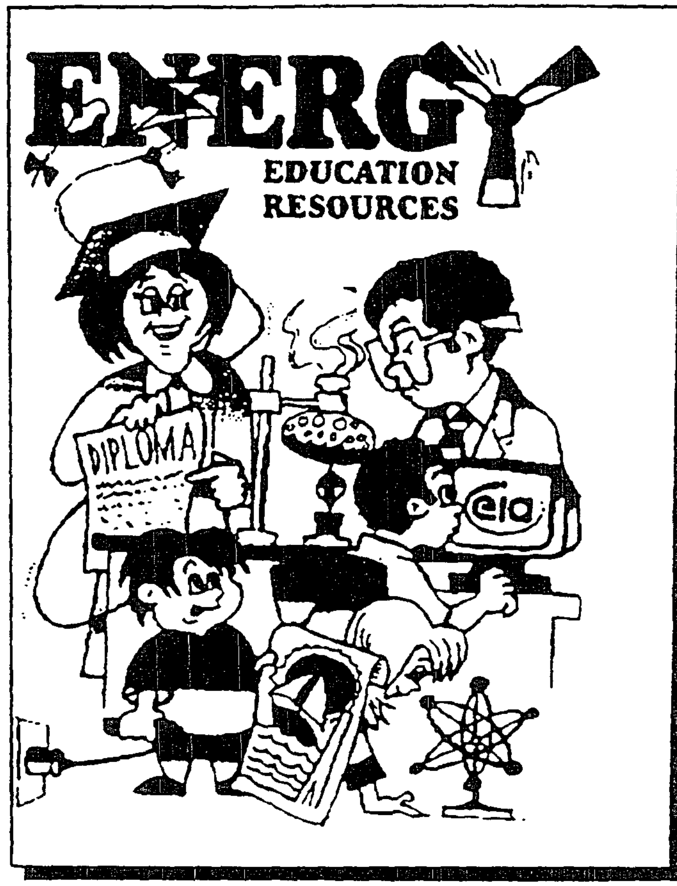
Attention, teachers and students!



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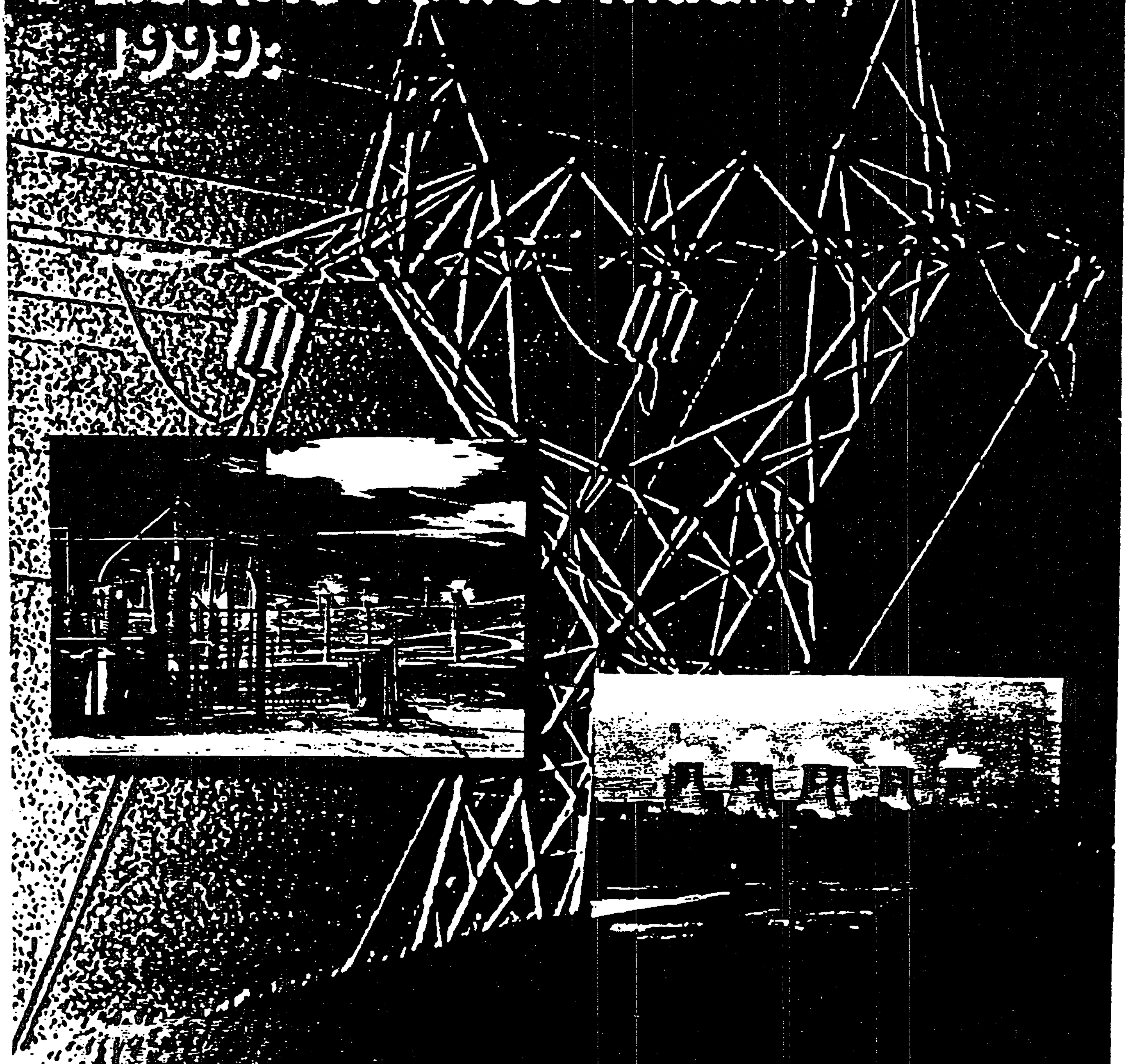

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The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations

December 1999

This report is available on the WEB at:

http://www.eia.doe.gov/cneaf/electricity/corp_str/corpcomb.pdf

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Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
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This report was prepared by the staff of the Electric Market Assessment Team, Office of Coal, Nuclear, Electric and Alternate Fuels. Questions about this publication, as well as other energy inquiries, may be directed to the National Energy Information Center on (202) 586-8800 or via Internet e-mail at infoctr@eia.doe.gov. This report is accessible via the Internet at http://www.eia.doe.gov/cneaf/electricity/page/pubs.html.

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Preface

Section 205(A)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data information program. Under this program, EIA will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information.

To assist in meeting these responsibilities, EIA has prepared this report, *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*, which is the latest in a series of reports covering key issues in the electric power industry. This series of reports is intended for use by the U.S. Congress, Federal and State government agencies, the electric power industry, and the general public.

EIA is an independent statistical agency, and it does not advocate positions on public policy issues. Its responsibility is to provide timely, high quality information, and to perform objective, credible analyses in support of deliberations by public and private organizations. Accordingly, this report does not represent any policy positions of the U.S. Department of Energy or the Administration.

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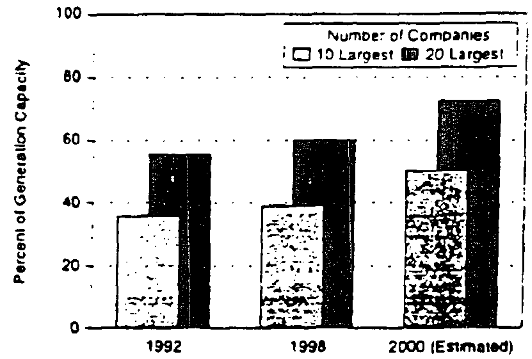
Executive Summary

Since the passage of the Energy Policy Act of 1992, which opened the U.S. electric power industry to the start of competition,[1] investor-owned electric utilities (IOUs) have been under pressure to cut costs, to become more efficient, and to expand their products and services. Mergers, acquisitions, asset divestitures, and other forms of corporate combinations have become widespread as IOUs seek to improve their positions in the increasingly competitive electric power industry. Since 1992 IOUs have been involved in 26 mergers, and an additional 16 mergers are pending approval. One effect of these mergers is that the industry is becoming more concentrated. In 1992 the 10 largest IOUs owned 36 percent of total IOU-held generation capacity, and the 20 largest IOUs owned 56 percent of IOU-held generation capacity (Figure ES1). By 2000, the 10 largest IOUs will own an estimated 51 percent of IOU-held generation capacity, and the 20 largest will own an estimated 73 percent.

Figure ES1. Concentration of Ownership of Investor-Owned Utility Generating Capacity, 1992, 1998, and 2000



Notes: • The ten largest companies are public utility holding companies that own one or more operating electric utilities. • The 2000 data assume that all pending mergers as of September 1999 will be completed by year-end 2000. • Capacity owned by subsidiaries of IOUs was not counted when computing the rankings.

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generation Report, 1992;" Form EIA-860A, "Annual Electric Generator Report - Utility, 1998;" and EIA-861, "Annual Electric Utility Report (1992 and 1998)."

In addition to mergers within the electricity industry, IOUs, seeing growth opportunities in the natural gas industry, are merging with or acquiring natural gas companies, contributing to what is referred to as "convergence" of the two industries. Since 1997, 20 convergence mergers involving companies with assets valued at $0.5 billion or higher have been completed or are pending completion. Combining energy marketing expertise, improving access to natural gas supply, and expanding products and services are reasons most often mentioned for the mergers.

Joint ventures and strategic alliances are alternative forms of corporate combinations used to meet the challenges of competition. Many IOUs have entered into ventures or alliances with other companies to construct or purchase power plants, to purchase energy products and services, and to market energy. The benefits of these arrangements are shared risks and costs.

Influenced predominantly by State-level electricity industry restructuring programs that emphasize the unbundling of generation from transmission and distribution, and in some cases by a desire to exit the competitive power generation business, IOUs are divesting power generation assets in unprecedented numbers. Starting in late 1997 through September 1999, IOUs collectively have divested or are in the process of divesting 133.0 gigawatts of power generation capacity, representing about 17 percent of total U.S. electric utility generation capacity. Divestiture means that the IOU will either sell its generation capacity to another company or transfer the generation capacity to an unregulated subsidiary within its own holding company structure.

Most of the sold capacity has been acquired by nonutility power producers that are subsidiaries of utility

[1] In general, competition means that electricity prices will be based on market forces as opposed to being administratively set, and that electricity markets will be open to more power suppliers than in the past.

holding companies. For the most part, the generation assets are sold through auctions. Final selling prices have been relatively high, usually 50 to 100 percent above book value (except for nuclear power plants, which have sold for less than book value).

As a result of mergers and divestitures over the past few years, the organizational structure of the electric power industry (i.e., the numbers and roles of the industry participants) is changing. The traditional role of the electric utility as a provider of electric power is giving way to the expanding role of nonutilities as providers of electric power. An analysis of electric power data collected by the Energy Information Administration for the period 1992 through 1998 offers the following insights:

- The number of IOUs has decreased by nearly 8 percent, while the number of nonutilities has increased by over 9 percent.
- Nonutilities are expanding and buying utility-divested generation assets, causing their net generation to increase by 42 percent and their nameplate capacity to increase by 72 percent from 1992 to 1998. Nonutility capacity and generation will increase even more as they acquire additional utility-divested generation assets over the next few years.
- The nonutility share of net generation has risen from 9 percent (286 million megawatthours) in 1992 to 11 percent (406 million megawatthours) in 1998.
- Utilities have historically dominated the addition of new capacity but additions to capacity by utilities are decreasing while additions by nonutilities are increasing. In the period 1985-1991, utilities were responsible for 62 percent of the industry's additions to capacity, but that figure dropped to 48 percent in the period 1992-1998.

1. Introduction

The electric utility industry, once highly regulated, is becoming more competitive. In the past, retail customers purchased electricity from local utilities. Now, in some States, retail customers can shop around for an alternative electricity supplier with lower prices or better services. The transition to a competitive market for electricity has started but is not complete, nor is it occurring uniformly across the country. As of mid-1999, about 24 States are implementing retail competition, and more States are expected to follow.[1]

At the national level, the Energy Policy Act of 1992 (EPACT) and orders by the Federal Energy Regulatory Commission (FERC), the agency responsible for regulating interstate commerce of electricity, have promoted wholesale electricity competition. EPACT makes it easier for certain independent electricity suppliers to generate electric power and sell the power in wholesale electricity markets by exempting them from the constraints of the Public Utility Holding Company Act of 1935 (PUHCA).[2] These independent electric companies compete against traditional electric utilities for the sale of electric power in wholesale and retail electricity markets. FERC Order 888 further promoted wholesale electricity competition by providing open access to the bulk power transmission grid to all electricity suppliers including power marketers, electric utilities, and nonutilities (i.e., power generation companies that are not utilities and therefore do not have a franchised service territory or own transmission facilities). Prior to Order 888, electric utilities owning bulk power transmission lines could restrict competitors' ability to move power by restricting access to their transmission lines.

Now that the industry is becoming more competitive, electricity suppliers are developing strategies to enhance their ability to compete. More and more the strategy involves a corporate combination such as a merger, joint venture, or business alliance to strengthen a company's position in the industry, or a divestiture of certain assets to refocus a company's business line. Corporate combinations are not new to the electric power industry. Mergers between electric utilities, for example, have been employed many times to improve a company's performance. Over the past few years, however, the size and frequency of mergers among investor-owned electric utilities (IOUs) have increased dramatically.

This report presents data about corporate combinations involving IOUs in the United States, discusses corporate objectives for entering into such combinations, and assesses their cumulative effects on the structure of the industry. From the combinations that have taken place over the past few years, three trends have emerged: (1) an increase in the size of IOUs and the concentration of generation capacity within the IOU sector; (2) an expansion of IOUs, which once focused mainly on electricity production and delivery, into the natural gas industry (a trend that has been labeled "convergence" in the trade press and elsewhere); and (3) the move of many vertically integrated IOUs (i.e., utilities that own generation, transmission, and distribution assets) to exit the power generation business to become "wire" companies, enabling them to concentrate solely on operating their transmission and distribution systems.

Chapter 2 presents an overview of ownership in the electric power industry, comparing the ownership structure from 1992 to 1998. It compares and analyzes changes in the number of companies and in the relative shares of nameplate capacity, net generation, and additions to capacity by type of ownership. The year 1992 was selected because it was the year in which EPACT was passed by the U.S. Congress, and it represents, to a large extent, the beginning of the restructuring of the electric power industry.

Chapter 3 discusses mergers and acquisitions among electric utilities. It takes a quantitative look at the trend in consolidation of generation capacity caused by mergers and acquisitions, followed by a brief discussion of the primary reasons for electric utility mergers. Next, there is a discussion of specific developments in the

[1] The Energy Information Administration's Internet site displays the status of State electricity industry restructuring programs (http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html)

[2] Appendix A contains a discussion of the Public Utility Holding Company Act of 1935.

industry related to the merger trend: (1) pending mergers that will create large vertically integrated power companies and significantly advance the consolidation trend in the industry; (2) the creation of large regional energy delivery companies; and (3) first-of-a-kind mergers involving electric utilities, independent power producers, and foreign utilities. The final section of the chapter discusses regulatory review of electric utility mergers and the FERC's role in ensuring Nonutilitythat combined companies will not have excess market power.

Chapter 4 discusses mergers and acquisitions between electric utilities and natural gas companies—or "convergence mergers." A combined natural gas and electric distribution utility is not new, but recent mergers involving vertically integrated electric utilities and integrated natural gas companies have created energy companies that produce, transport, market, and sell both gas and electricity. The chapter includes a listing of convergence mergers and a discussion of the rationale behind some of the major ones.

Two different forms of corporate combinations—joint ventures and marketing alliances of electric utilities—are discussed in Chapter 5. Many utilities enter joint ventures or marketing alliances in order to share the costs of new ventures, reduce risks, or capitalize on the expertise of other companies. Joint ventures and alliances have been around for some time, but in today's environment they tend to be used more.

Over the past year or more, many IOUs have sold some or all of their power generation assets. This trend is new to the electric power industry, and it signifies fundamental changes in corporate ownership of power generation in the United States. Chapter 6 analyzes utility divestitures of generating assets, which are expected to continue as more States move to restructure the electricity industry in their jurisdictions.

Appendix A presents a discussion of the Public Utility Holding Company Act of 1935. Many industry observers believe that this Act unfairly constrains registered holding companies, is no longer relevant in today's industry, and, therefore, should be repealed. Proposals to repeal or modify the Act have been introduced into the current Congress and are summarized in the appendix.

Appendix B contains case studies describing the process of asset divestiture for three utilities. It discusses the reasons given by the utilities for divesting their assets, the auction process, and special issues that may affect the selling of power generation assets.

Appendices C and D are two detailed case studies of electric utility mergers. Significant cost savings are almost always used to justify mergers to the regulatory authorities responsible for approving them. The objective of the case studies was to determine, using public data, whether the mergers resulted in the savings originally estimated by the companies.

Appendix E contains definitions of various types of corporate combinations.

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2. Organizational Components of the Electric Power Industry

This chapter examines the components that make up the infrastructure of the electric power industry. It explains their ownership characteristics, their current role in electricity supply, and how some roles have shifted since passage of the Energy Policy Act of 1992 (EPACT). EPACT, which provided a Federal mandate to open up the national electricity transmission system to wholesale suppliers, marked the beginning of competition in the electric power industry and was the impetus for significant structural changes. In 1996, the Federal Energy Regulatory Commission (FERC) issued its Order 888, which carried out the goal of EPACT.[3] From the 1970s until 1992, little change had occurred in the industry, either structurally or operationally, with the exception of the creation of nonutility qualifying facilities brought about by the Public Utility Regulatory Policies Act of 1978 (PURPA).[4] The data presented in this analysis are for 1998. In some cases, data for 1992 are compared with 1998 data to show trends.

Generation of electricity in the United States is performed by two types of companies—utilities and nonutilities. Table 1 presents their numbers and characteristics by ownership category. An electric utility is a private company or public agency engaged in the generation, transmission, and/or distribution of electric power that is given a monopoly franchise over a specific geographic area. In return for this franchise, the electric utility is regulated by State and Federal agencies. Utilities can be further classified into four subcategories based on ownership—investor-owned (IOU), Federally owned, other publicly owned, and cooperatively owned. Recently a fifth subcategory of electric utilities has emerged—the power marketers. They are classified as electric utilities because they buy and sell electricity. However, they do not own or operate generation, transmission, or distribution facilities, and therefore, their data (primarily electricity purchase and sales data) are not included in this chapter, except to give their characteristics in Table 1. Although relatively small in terms of volume of sales, the power marketers are a growing segment of the industry. Currently, about 400 power marketers have filed rate tariffs with FERC to sell electric power. Forty-nine power marketers reported retail sales and 111 reported wholesale sales during 1998.

In addition to power marketers, several other entities have come into existence as a result of the move to competition and can be added to the operational underpinnings of the electric power industry—namely, regional independent transmission system operators (ISOs), power exchanges (PXs), and futures contracts. Power marketers are the only one of the new entities that report to the Energy Information Administration (EIA) in its ongoing data collection program.[5]

Nonutilities are companies that generate power for their own use and/or for sale in wholesale markets.[6] Past EIA reports have subcategorized nonutilities (for example, as qualifying or nonqualifying facility cogenerators, small power producers, exempt wholesale generators, etc.[7]) based on their qualifications under certain Federal laws. However, as the industry furthers its transition to full retail competition in the generation portion of electricity

[3] FERC could not mandate an electric utility to open its transmission system for wholesale electric trade until EPACT amended the Federal Power Act.

[4] For further details on qualifying facilities and the Public Utility Regulatory Policies Act of 1978 and other laws that have had significant impacts on electric power supply, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), Chapter 4.

[5] For details surrounding these recently emerged elements, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), and *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE/EIA-0562(98) (Washington, DC, July 1998).

[6] Another term for a nonutility is an "independent power producer" (IPP). The two terms are used interchangeably throughout this report.

[7] For details on each of these nonutility subsections, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 13-15.

Table 1. Major Characteristics of Electricity Providers by Type of Ownership, 1998

Ownership	Major Characteristics
Investor-Owned Utilities (IOUs) IOUs account for about three-quarters of all utility generation and capacity. There are 239 in the United States, and they operate in all States except Nebraska. They are also referred to as privately owned utilities.	• Earn a return for investors; either distribute their profits to stockholders as dividends or reinvest the profits • Are granted service monopolies in specified geographic areas • Have obligation to serve and to provide reliable electric power • Are regulated by State and Federal governments, which in turn approve rates that allow a fair rate of return on investment • Most are operating companies that provide basic services for generation, transmission, and distribution
Federally Owned Utilities There are 10 Federally owned utilities in the United States, and they operate in all areas except the Northeast, the upper Midwest, and Hawaii.	• Power not generated for profit • Publicly owned utilities, cooperatives, and other nonprofit entities are given preference in purchasing from them • Primarily producers and wholesalers • Producing agencies for some are the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the International Water and Boundary Commission • Electricity generated by these agencies is marketed by Federal power marketing administrations in the U.S. Department of Energy • The Tennessee Valley Authority is the largest producer of electricity in this category and markets at both wholesale and retail levels
Other Publicly Owned Utilities Other publicly owned utilities include: Municipals Public Power Districts State Authorities Irrigation Districts Other State Organizations There are 2,009 in the United States.	• Are nonprofit State and local government agencies • Serve at cost; return excess funds to the consumers in the form of community contributions and reduced rates • Most municipals just distribute power, although some large ones produce and transmit electricity; they are financed from municipal treasuries and revenue bonds • Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California; voters in a public power district elect commissioners or directors to govern the district independent of any municipal government • Irrigation districts may have still other forms of organization (e.g., in the Salt River Project Agricultural Improvement and Power District in Arizona, votes for the Board of Directors are apportioned according to the size of landholdings) • State authorities, such as the New York Power Authority and the South Carolina Public Service Authority, are agents of their respective State governments
Cooperatively Owned Utilities There are 912 cooperatively owned utilities in the United States, and they operate in all States except Connecticut, Hawaii, Rhode Island, and the District of Columbia.	• Owned by members (rural farmers and communities) • Provide service mostly to members • Incorporated under State law and directed by an elected board of directors which, in turn, selects a manager • The Rural Utilities Service (formerly the Rural Electrification Administration) in the U.S. Department of Agriculture was established under the Rural Electrification Act of 1936 with the purpose of extending credit to co-ops to provide electric service to small rural communities (usually fewer than 1,500 consumers) and farms where it was relatively expensive to provide service
Nonutilities There are 1,934 nonutility power producers in the United States.	• Generate power for their own use and/or for sale in wholesale power markets • Can be subcategorized as qualifying facility (QF) cogenerators, non-QF cogenerators, QF small power producers, exempt wholesale generators, and/or non-QF other. • Also generally referred to as independent power producers
Power Marketers Approximately 400 have filed with FERC.	• Some are utility-affiliated while others are independent • Buy and sell electricity • Do not own or operate generation, transmission, or distribution facilities

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

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supply, the distinctions between the nonutility subcategories are becoming less clear, and some may fade entirely within the next 10 years as a result of ongoing structural changes and the imminent repeal of the Federal mandates that created them. For purposes of this report, nonutility data are reported in the aggregate.

Utilities and nonutilities can also be broken down in a different manner, i.e., the number of companies that generate, transmit, and/or distribute electric power. It is interesting to note that only about 27 percent of the Nation's 3,170 utilities actually generate electric power. Many electric utilities (67 percent) are exclusively distribution utilities, purchasing wholesale power from others to distribute it, over their own distribution lines, to the ultimate consumer. These are primarily the utilities owned by State and local governments and cooperatives. Conversely, all nonutilities generate power but do not own or operate transmission or distribution systems (Table 2).

The relative contribution of utility and nonutility components to the supply of the Nation's electricity can be understood by looking at their shares of nameplate capacity,[8] net generation,[9] additions to capacity, and number of companies (Figure 1). The number of publicly owned utilities (i.e., those owned by State and local governments) far outweighs the number of IOUs (2,009 versus 239); however, IOUs are responsible for the lion's share of capacity (66 percent) and generation (68 percent). On the other hand, the nonutility share of capacity and generation has been relatively small, but that trend is changing. The change began with the passage of PURPA when nonutilities were promoted as energy-efficient, environment-friendly alternative sources of electricity. More recently, FERC Order 888 opened the bulk power transmission grid to suppliers other than utilities. In response, nonutilities have been expanding their roles in wholesale power supply and are taking advantage of the divestiture activities of utilities by purchasing their generation assets. As a result, the nonutility share of total industry capacity rose from 7 percent in 1992 to 12 percent in 1998.[10]

A yearly comparison of the above-mentioned four statistics (Figure 2) gives a clear picture of the significant shifts in ownership of electricity supply that have taken place in the relatively short period of time since passage of EPACT. A number of these shifts can be attributed to the strategic business plans companies are using to cope in a deregulated and competitive market. For instance, since 1992, the number of IOUs has decreased by nearly 8 percent and their nameplate capacity has decreased by 5 percent (Figure 3). The decrease in the number of IOUs is a result of recent mergers between IOUs. The decrease in generation capacity is evidence of divestiture of generation assets. On the other hand, the fact that IOU net generation has actually increased by 11 percent since 1992 can be attributed to such factors as higher demand for electricity or efficiency gains stemming from competition and mergers.

Although there was a drop in the number of nonutility companies in 1997, nonutilities grew by over 9 percent during the 7-year period examined. Also, with nonutilities expanding by buying IOU generation assets and constructing new generation units, the result was an increase in nonutility nameplate capacity (up 72 percent since 1992) and generation (up 42 percent since 1992). Nonutility additions to capacity have been increasing at an average annual rate of nearly 7 percent since 1992.

Historically, utilities have generally been vertically integrated companies that provided for generation, transmission, and/or distribution for all customers in a designated franchised service territory. Currently, the industry is in transition from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation. Market forces will replace State and Federal regulators in setting the price and terms of electricity supply and are expected to lead to lower rates for customers. In addition, the individual States are moving toward opening their retail markets to competition. The transition has begun to induce many far-reaching changes in the structure of the industry (and the institutions that govern it) especially through the corporate combinations that are the subject of this report. The following chapters address the objectives, characteristics, and cumulative effects of these corporate combinations—mergers and acquisitions, convergence mergers, joint ventures and marketing alliances, and divestitures of generation assets.

[8] EIA defines nameplate capacity as the maximum design production capacity specified by the manufacturer of a processing unit or the maximum amount of a product that can be produced running the manufacturing unit at full capacity.

[9] EIA defines net generation as gross generation minus plant use from all electric utility-owned plants.

[10] Energy Information Administration, *1998 Electric Power Annual, Volume I* (DOE/EIA-0348(98)/1) (Washington, DC, April 1999), p. 1.

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Table 2. Energy Supply Participants and Their Operations, 1998

Participants/Operations	Number of Companies	Percent of All Utilities
Vertically Integrated (Generate,[a] Transmit,[b] and Distribute[c])		
Utilities Only		
Investor Owned	140	4.4
Federal	3	0.1
Publicly Owned	132	4.2
Cooperatives	20	0.6
Total	295	9.3
Generate and Transmit Only		
Utilities Only		
Investor Owned	10	0.3
Federal	3	0.1
Publicly Owned	36	1.1
Cooperatives	40	1.3
Total	89	2.8
Transmit and Distribute Only		
Utilities Only		
Investor Owned	6	0.2
Federal	1	0.0
Publicly Owned	58	1.8
Cooperatives	74	2.3
Total	139	4.4
Generate and Distribute Only		
Utilities Only		
Investor Owned	25	0.8
Federal	2	0.1
Publicly Owned	403	12.7
Cooperatives	23	0.7
Total	453	14.3
Generate Only		
Utilities		
Investor Owned	11	0.3
Federal	0	–
Publicly Owned	12	0.4
Cooperatives	1	0.0
Total	24	0.8
Nonutilities	1,930	[d]100.0
Transmit Only		
Utilities Only		
Investor Owned	7	0.2
Federal	0	–
Publicly Owned	8	0.3
Cooperatives	19	0.6
Total	34	1.1

See notes at end of table.

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Table 2. Energy Supply Participants and Their Operations, 1998 (Continued)

Participants/Operations	Number of Companies	Percent of All Utilities
Distribute Only		
Utilities Only		
Investor Owned	34	1.1
Federal	1	0.0
Publicly Owned	1,358	42.8
Cooperatives	735	23.2
Total	2,128	67.1
Other[e]		
Utilities Only		
Investor Owned	6	0.2
Publicly Owned	2	0.1
Total	8	0.2
Power Marketers[f]	[g]400	–

[a]An electricity generator is a facility that converts mechanical energy into electrical energy.

[b]An electricity transmitter moves or transfers electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

[c]An electricity distributor delivers electric energy to an end user.

[d]This figure represents the percentage of nonutilities rather than utilities.

[e]"Other" includes maintenance service companies for parent utilities that perform such functions as guard services, equipment maintenance, etc. Also, one of the publicly owned utilities in this category acts as an agent to buy and schedule power for the parent utility.

[f]An electricity power marketer buys and sells electricity but does not own or operate generation, transmission, or distribution facilities.

[g]Currently, about 400 power marketers have filed rate tariffs with FERC; 111 reported wholesale sales and 49 reported retail sales during 1998.

– = Not applicable.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report, 1998," and EIA-860B, "Annual Electric Generator Report - Nonutility, 1998."

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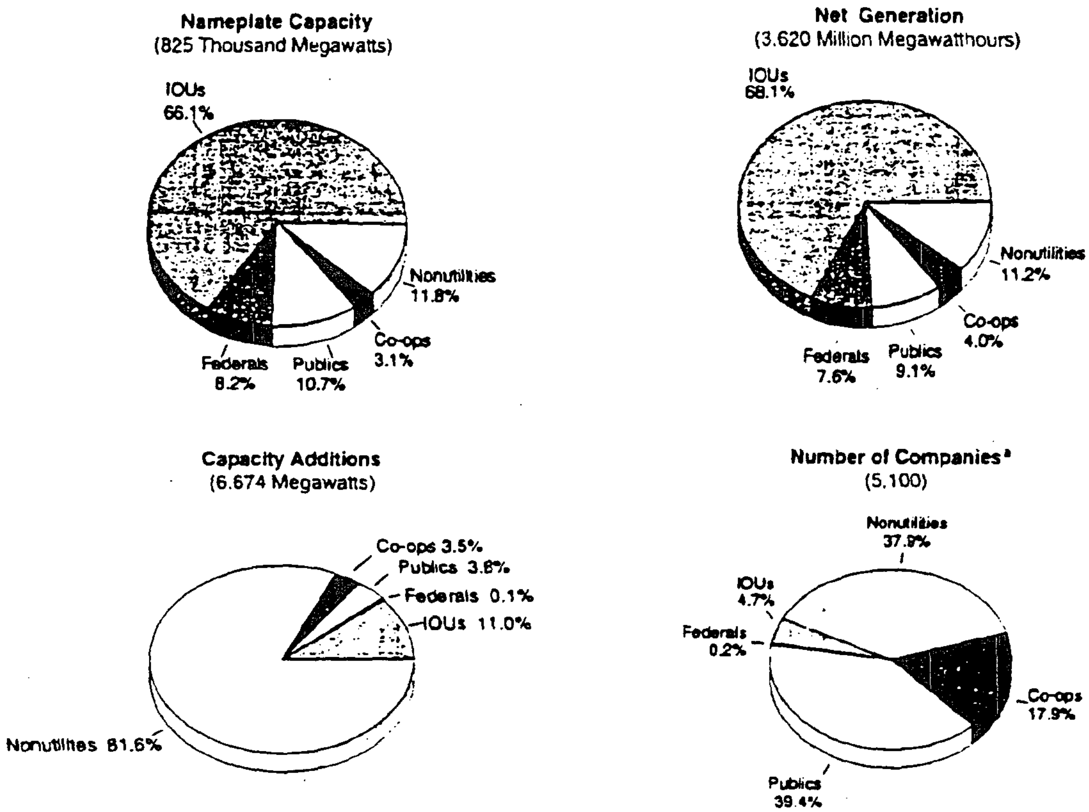
Figure 1. Share of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report, December 1998;" EIA-860A, "Annual Electric Generator Report - Utility, 1998;" EIA-861, "Annual Electric Utility Report, 1998;" and EIA-860B, "Annual Electric Generator Report - Nonutility, 1998."

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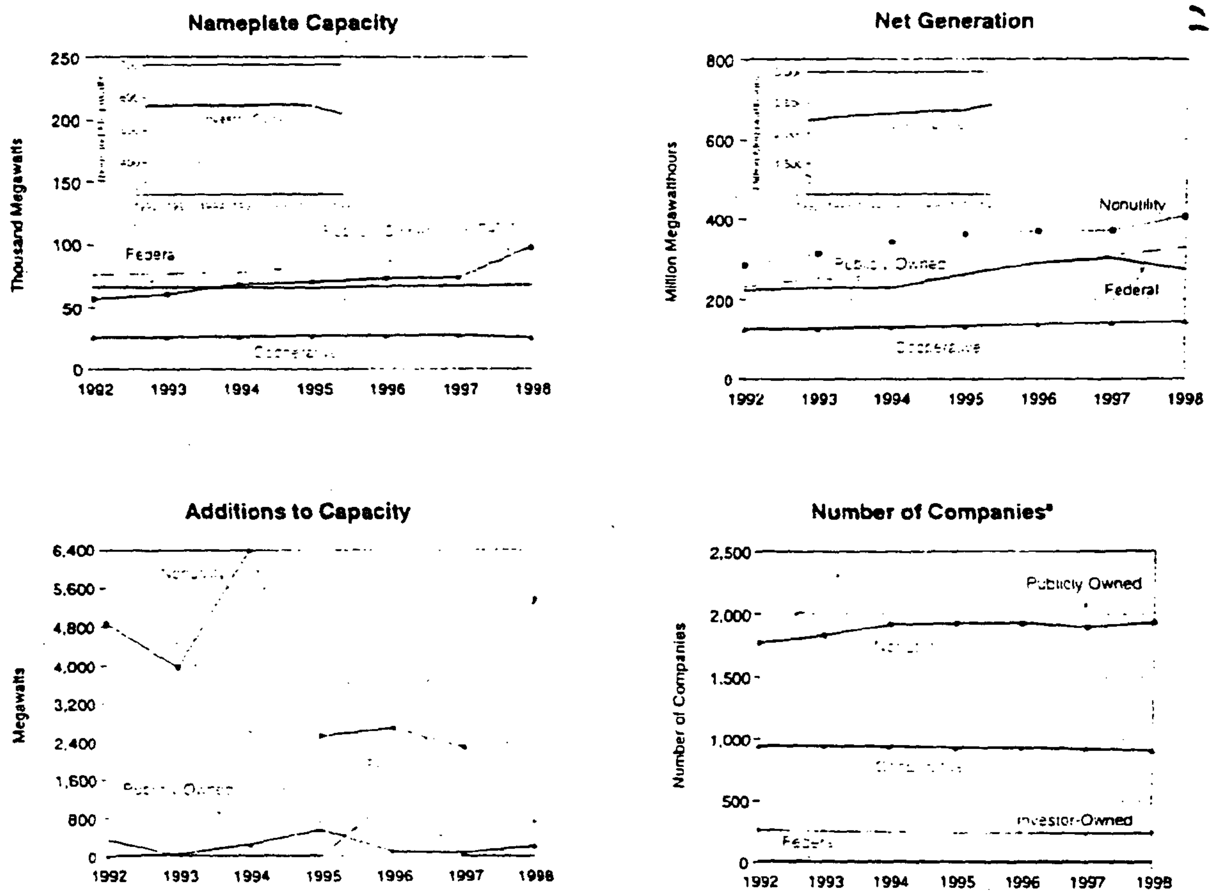
Figure 2. Total Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1992-1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report, January 1992 through December 1998;" Form EIA-860, "Annual Electric Generator Report, 1992 through 1997;" EIA-860A, "Annual Electric Generator Report - Utility, 1998;" EIA-861, "Annual Electric Utility Report, 1992 through 1998;" EIA 867, "Annual Nonutility Power Producer Report, 1992 through 1997;" and EIA-860B, "Annual Electric Generator Report - Nonutility, 1998."

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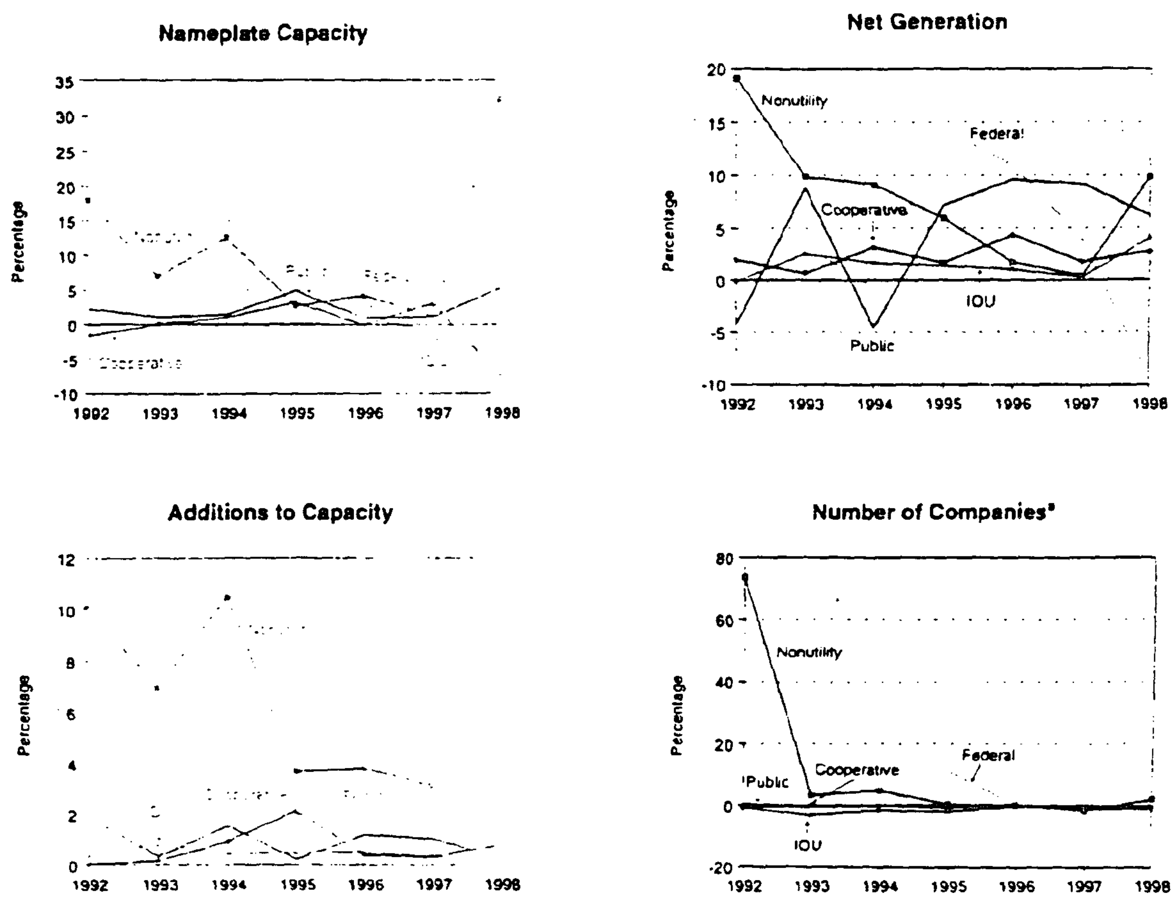
Figure 3. Annual Growth Rate of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Companies, 1992-1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report, January 1992 through December 1998;" Form EIA-860, "Annual Electric Generator Report, 1992 through 1997;" EIA-860A, "Annual Electric Generator Report - Utility, 1998;" EIA-861, "Annual Electric Utility Report, 1992 through 1998;" EIA 867, "Annual Nonutility Power Producer Report, 1992 through 1997;" and EIA-860B, "Annual Electric Generator Report - Nonutility, 1998."

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3. Mergers and Acquisitions of Investor-Owned Electric Utilities

Mergers and acquisitions are occurring throughout the U.S. economy, and the electric power industry is no exception.[11] Since 1992, 26 mergers or acquisitions have been completed between investor-owned utilities (IOUs) or between IOUs and independent power producers (IPPs). Sixteen mergers have been announced and are now pending stockholder or Federal and State government approval (Table 3).[12] The size of IOU mergers, in terms of value of assets, is also getting larger. Between 1992 and 1998, only four mergers were completed in which the combined assets of the companies in each merger were greater than $10 billion. More recently, 10 mergers either completed in 1999 or pending completion each have combined assets greater than $10 billion.

The current wave of mergers and acquisitions is not the first wave in the electric power industry. From 1917 through 1930, mergers of electric utilities were more common than at any other time in the history of the industry. Mergers occurred at a rate of more than 200 per year, peaking at over 300 per year in the mid-1920s.[13] Most of the mergers in the 1920s combined small operating companies into large holding companies. These holding companies acquired numerous and widely scattered utility and nonutility properties throughout the United States, and they became a dominant force in the industry by permitting concentration of control of many electric utilities in the hands of a few. This era can clearly be considered the first wave of mergers in the history of the industry, but it came to an end in 1935.

In the early 1930s many of the holding companies collapsed financially. The Federal Trade Commission (FTC) investigated the situation and uncovered a host of financial abuses, leading to passage of the Public Utility Holding Company Act of 1935 (PUHCA). (See Appendix A for a discussion of the Act.) Among other things, the Act resulted in the reorganization and divestiture of assets of many of the holding companies, and the requirement that the remaining holding companies be limited to a single integrated electricity system. Between 1935 and 1950, more than 750 utilities were spun off from the holding companies, and by the early 1950s compliance with the requirements of PUHCA were nearing completion.

Following the breakup of the large holding companies, mergers continued, but at a much lower rate. From 1936 through 1975 there were 517 mergers, occurring at an annual rate of less than 15 a year. From 1976 through 1998, 76 mergers have taken place, about 3 per year on average. The distinguishing difference between the heyday of mergers occurring early in the industry and now, is the relative size of the mergers. It is no longer smaller companies being acquired by large companies, but in many cases it is large companies merging with other large companies. "Mega-mergers" is the term used to describe such large mergers.

Some financial analysts say that good economic conditions and relatively high stock values are responsible for the current wave of electric utility mergers. High stock prices allow companies to take an inexpensive source of capital (common stock in this case) and buy other companies in a stock-for-stock transaction. However, the current wave of utility mergers is probably driven more by increasing competition in the electric power industry, although financial factors play a part. Mergers of IOUs can be classified broadly into two categories, each category representing a fundamentally different reason for merging. The first category includes mergers between IOUs and mergers between IOUs and

[11] For this report no attempt was made to classify a transaction as a merger or acquisition, although there is a difference in terms of how the financial accounting of the transaction is recorded. Throughout the report, the transactions are collectively referred to as mergers and acquisitions or mergers.

[12] This report covers IOU acquisitions of other electric utilities, privately owned IPPs, and companies involved in the natural gas industry. It does not cover IOU acquisitions of foreign companies or non-energy-related companies.

[13] National Regulatory Research Institute, Electric Utility Mergers and Regulatory Policy, Occasional paper #16, NRRI 92-12 (June, 1992).

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Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**Allegheny Energy, Inc.** (a registered holding company for Monongahela Power Co.,The Potomac Edison Co., West Penn Power, Allegheny Generating Co., and Ohio Valley Electric Corp.)	**DQE, Inc.** (a holding company for Duquesne Light Co.)	**Allegheny Energy, Inc.** (DQE will be a wholly-owned subsidiary of Allegheny Energy, Inc.)	PA, WV, OH, MD	Allegheny: $6.7 DQE: $5.2 Total: $11.9	DQE informed Allegheny that it has terminated the merger plan. Allegheny took legal action in Federal Court to compel DQE to honor its obligation. Case is pending.
Pending	**Western Resources** (a holding company for Kansas Gas and Electric Co.; partial owner of Wolf Creek Nuclear Operating Co.)	**Kansas City Power & Light** (an operating utility)	**Westar Energy** (proposed name of new holding company)	KS, MO	Western: $8.0 Kansas City P&L: $3.0 Total: $11.0	Under State regulatory review.
Pending	**American Electric Power Co., Inc.** (a registered holding company for AEP Generating Co., Appalachian Power Co., Columbus Southern Power, Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co.)	**Central and South West Corp.** (a registered holding company for Central Power and Light Co., Public Service Co. of Oklahoma, Southwestern Electric Power Co., and West Texas Utilities Co.)	**American Electric Power Co.** (Central and South West will be a wholly-owned subsidiary)	VA, WV OH, IN MI, KY TN, TX OK, LA AR	AEP: $19.5 CSW: $13.7 Total: $33.2	On July 23, 1999, the Federal Energy Regulatory Commision (FERC) filed an order accelerating the schedule for review of this merger. The FERC's goal is to act on the merger in February or March 2000.
Pending	**Nevada Power** (an operating utility)	**Sierra Pacific Resources** (a holding company for Sierra Pacific Power Co.)	**Sierra Pacific Resources** (Nevada Power will be a wholly-owned subsidiary)	NV, CA	Nevada Power: $2.6 Sierra Pacific: $2.0 Total: $4.6	Received FERC and Department of Justice (DOJ) approval. Completion of merger expected in next few months
Pending	**Consolidated Edison, Inc.** (a holding company for Consolidated Edison Co. of New York, Inc., and Orange and Rockland Utilities)	**Northeast Utilities** (a holding company for Connecticut Light & Power, Public Service Co. of New Hampshire, and Western Massachusetts Electric Co.)	**Consolidated Edison, Inc.** (Northeast Utilities will be a subsidiary)	NY, CT, MA, NH	Consolidated Edison: $14.4 Northeast: $10.4 Total: $24.8	Merger was announced October 13, 1999.
Pending	**AES Corporation** (an independent power producer)	**CILCORP** (a holding company for Central Illinois Light Co.)	**AES** (CILCORP will be a wholly-owned subsidiary)	IL	AES: $10.0 CILCORP: $1.3 Total: $11.3	Under SEC review; has completed all other reviews.
Pending	**BCE Energy** (a holding company for Boston Edison)	**Commonwealth Energy** (a holding company for Cambridge Electric Light Co., Canal Electric Co., and Commonwealth Electric Co.)	**NSTAR** (a new holding company; Boston Edison and Commonwealth Energy will be subsidiaries)	MA	BCE: $3.2 Commonwealth: $1.5 Total: $4.7	Under regulatory review.

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**Scottish Power PLC** (a foreign company)	**PacifiCorp** (an operating utility)	Unknown (a new holding company; PacifiCorp will be a subsidiary)	UT, OR, WY, WA, ID, MT, CA	Not available because Scottish Power is a foreign company.	Pending shareholder and regulatory approval; they hope to complete merger by late 1999.
Pending	**National Grid Group PLC** (a foreign company)	**New England Electric Systems (NEES)** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	**National Grid Group** (NEES will be a wholly-owned subsidiary)	VT, NH MA	Not available because National Grid Group is a foreign company.	Pending regulatory approval.
Pending	**Carolina Power & Light Co.** (an operating utility)	**Florida Progress Corp.** (a holding company for Florida Power Corp.)	Unknown	FL, NC, SC	CP&L: $8.3 Florida: $6.2 Total: $14.5	This merger was announced on August 23, 1999.
Pending	**New England Electric System** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	**Eastern Utility Associates** (a registered holding company for Blackstone Valley Electric Co., Newport Electric Corp., Eastern Edison Co., EUA, and Ocean State Corp.)	**New England Electric System** (EUA will be a wholly-owned subsidiary)	MA, RI VT, NH	NEES: $5.3 EUA: $1.3 Total: $6.6	EUA shareholders approved merger; pending regulatory review; expected to be completed in early 2000.
Pending	**UtiliCorp United** (a holding company)	**St. Joseph Light & Power** (an operating utility)	**Utilicorp** (St. Joseph will keep its name and become a wholly-owned subsidiary)	MO, KS CO, WV CO, KA	Utilicorp: $6.0 St. Joseph: $0.3 Total: $6.3	Under regulatory review.
Pending	**New Century Energies** (a registered holding company for Public Service Co. of Colorado, Southwestern Public Service Co., and Cheyenne Light, Fuel, & Power)	**Northern States Power** (a holding company)	**Xcel Energy** (unknown if New Centuries and Northern States Power operate as subsidiaries)	NM, OK TX, WY AR, MI MN, SD ND, WI	New Century: $7.7 NSP: $7.4 Total: $15.1	Under regulatory review.
Pending	**UtiliCorp United** (a holding company)	**Empire District Electric Co.** (an operating utility)	Unknown	MO, CO KA, WV OK, AR	Utilicorp: $6.3 Empire District: $0.7 Total: $7.0	Under regulatory review.

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**Energy East** (a holding company for New York Electric & Gas)	**CMP Group** (a holding company for Central Maine Power)	**Energy East** (CMP Group will be a wholly-owned subsidiary)	MA, MI NY, NH	Energy East: $4.9 CMP Group: $2.3 Total: $7.2	This merger was announced on June 15, 1999.
Pending	**Unicom Corporation** (a holding company for Commonwealth Edison)	**PECO Energy Co.** (a registered holding company for Susquehanna Power Co.)	A new holding company, to be named later, will be created.	IL, PA	Unicom: $30.2 Peco: $12.0 Total: $42.2	This merger was announced September 23, 1999.
Completed in 1999 (year-to-date)	**CalEnergy Co., Inc.** (an independent power producer)	**MidAmerican Energy Holding Co.** (a holding company for MidAmerican Energy Co.)	**MidAmerican Energy Holding** (CalEnergy will be a subsidiary)	KS	CalEnergy: $7.5 MidAmerican: $4.3 Total: $11.8	Completed.
	Consolidated Edison, Inc. (a holding company for Consolidated Edison Co. of New York, Inc.)	**Orange and Rockland Utilities** (an operating utility)	**Consolidated Edison, Inc.** (Orange and Rockland will be a wholly-owned subsidiary)	NY	ConEd: $14.4 O&R: $1.3 Total: $15.7	Completed.
Completed in 1998	**Delmarva Power & Light Co.** (an operating utility)	**Atlantic Energy** (a holding company for Atlantic City Electric Co.)	**Conectiv** (a new registered holding company)	MD, DE VA, NJ	Delmarva Power: $3.0 Atlantic: $2.7 Total: $5.7	Completed.
	LG&E Energy (a holding company for Louisville Gas & Electric Co.)	**KU Energy** (a holding company for Kentucky Utilities)	**LG&E Energy** (KU Energy will be dissolved)	KY, VA TN	LG&E: $3.0 KU Energy: $1.7 Total: $4.7	Completed.
	WPL Holding, Inc. (a holding company for Wisconsin Power & Light)	**IES Industries** (a holding company for IES Utilities and Interstate Power, an operating utility)	**Alliant Energy** (a new holding company)	WI, IA MN, IL	WPL Holding: $1.9 IES: $2.5 Interstate: $0.6 Total: $5.0	Completed.
	Wisconsin Energy (a holding company for Wisconsin Electric Power Co.)	**ESELCO** (a holding company for Edison Sault Electric Co.)	**Wisconsin Energy Company** (ESELCO will be a wholly-owned subsidiary)	WI, MI	Wisconsin: $5.0 ESELCO: $0.1 Total: $5.1	Completed.
	WPS Resources (a holding company for Wisconsin Public Service Corp., Wisconsin River Power Co.)	**Upper Peninsula Energy** (a holding company for Upper Peninsula Power Co.)	**WPS Resources** (Upper Peninsula Energy will cease to exist)	WI, MI	WPS: $1.1 Upper Peninsula: $0.1 Total: $1.2	Completed.

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Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1997	Ohio Edison Co. (an operating utility; Ohio Edison also owns Pennsylvania Power Co.)	Centerior Energy (a holding company for Cleveland Electric Illuminating Co. and Toledo Edison Co.)	FirstEnergy (a new registered holding company)	OH	Ohio Edison: $8.9 Centerior: $10.2 Total: $19.1	Completed.
	Public Service Co. of Colorado (an operating utility and a holding company for Cheyenne Light, Fuel, and Power)	Southwestern Public Service Co. (an operating utility)	New Century Energies (a new registered holding company)	CO, TX NM, OK KS	PS Co. of CO: $4.6 Southwestern: $2.0 Total: $6.6	Completed.
	Union Electric Co. (an operating utility)	CIPSCO (a holding company for Central Illinois Public Service Co.)	Ameren (a new registered holding company)	MO, IL	Union: $6.8 CIPSCO: $1.8 Total: $8.6	Completed.
	Pacific Gas & Electric Corp. (a holding company for Pacific Gas & Electric)	U.S. Generating Co. (USGen) (an independent power producer)	Pacific Gas & Electric Corp. (USGen will be an unregulated affiliate of PG&E)	USGen has plants in numerous States	USGen: $5.0	PG&E acquired 50 percent in USGen. At the time, USGen had ownership in 17 electric generating facilities operating in the United States.
Completed in 1996	New England Electric Systems (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragan-sett Electric Co., and New England Power Co.)	Nantucket Electric (a small electric distribution company)	New England Electric System (Nantucket Electric is a subsidiary)	VT, NH MA	NEES: $5.1 Nantucket: $0.1 Total: $5.2	Completed.
Completed in 1995	City of Groton, CT	Bozrah Light and Power	Unknown	CT	Unknown	Completed.
	Delmarva Power and Light	Conowingo Power Co.	Delmarva Power and Light	DE,MD, VA	Delmarva Power: $2.9 Conowingo: $0.1 Total: $3.0	Completed.
	Midwest Resources (a holding company for Midwest Power Systems)	Iowa-Illinois Gas and Electric (an operating utility)	MidAmerican Energy (a holding company and operating utility)	IA, SD, IL	Midwest: $2.6 Iowa: $1.9 Total: $4.5	Completed.
Completed in 1994	PSI Resources (an operating utility)	Cincinnati Gas & Electric (an operating utility)	CINergy (PSI Resources and Cincinnati are wholly-owned subsidiaries)	IN,OH, KY	PSI Resources: $2.9 Cincinnati: $5.2 Total: $8.1	Completed.

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1993	**Citizens Utilities Co.** (an operating utility)	**Franklin Electric** (an operating utility)	**Citizens Utilities** (Franklin Electric ceased to exist)	AZ,HI, VT	Citizens: $2.6 Franklin: $0.8 Total: $3.4	Completed.
	IES Utilities Inc. (a holding company)	**Iowa Electric Light & Power and Iowa Southern Utilities**	**IES Industries** (IES Utilities, Iowa Electric, and Iowa Southern are subsidiaries)	IA	Total: $1.8	Completed.
	Texas Utilities (a holding company)	**Southwestern Electric Service Co.** (an operating utility)	**Texas Utilities** (Southwestern Electric is a subsidiary)	TX	Total: $20.9	Completed.
	Entergy Corp. (a holding company)	**Gulf States Utilities** (a holding company)	**Entergy Corp.** (Gulf States is a wholly-owned subsidiary)	AR,TN, LA, TX, MS, NY	Entergy: $14.2 Gulf States: $7.2 Total: $21.4	Completed.
Completed in 1992	**Connecticut Light & Power**	**Fletcher Electric Light Co.**	**Connecticut Light and Power**	CT	Total: $6.2	Completed.
	Iowa Public Service Co.	**Iowa Power Co.**	**Midwest Power**	IA, SD	Total: $2.6	Completed.
	Kansas Power & Light	**Kansas Gas & Electric**	**Western Resources**	KS	Total: $5.2	Completed.
	Indiana Michigan Power Co.	**Michigan Power Co.**	**Indiana Michigan Power Co.**	IN, MI	Total: $4.3	Completed
	Unitil Corp.	**Fitchburg Gas & Electric**	**Unitil Corp.**	NH	Total: $0.2	Completed.
	Northeast Utilities	**Public Service of New Hampshire**	**Northeast Utilities**	NH, CT, MA	Total: $10.6	Completed.

Notes: U.S. investor-owned electric utility acquisitions of foreign companies are not included in this table.
Sources: Mergers and acquisitions were identified from trade journals, newspapers, and electric utility press releases found on their websites. Values for company assets were obtained from the Securities and Exchange Commission, 10-K filings.

IPPs. These mergers are motivated by the desire to increase power generation capacity and/or transmission and distribution capacity and in general become a larger electric utility. Most utility executives take the position that to compete successfully in today's electricity industry, a company must be relatively large.

The second category includes mergers between electric utilities and natural gas companies. These mergers are motivated by the desire to become a regional or national energy company that produces, transports, and/or sells both electricity and natural gas. Mergers of this type are called "convergence mergers" because they represent the increasing number of companies that own both electricity and natural gas assets and are actively engaged in both industries. Convergence mergers are discussed in Chapter 4.

Investor-Owned Electric Utilities Consolidating Generation Assets Through Mergers and Acquisitions

Mergers and acquisitions among IOUs over the past few years have resulted in fewer electric utilities owning generation capacity. In 1992, 172 IOUs owned generation capacity in the United States. By 1998 that number had decreased to 161 (Table 4).[14] Assuming that all mergers pending as of September 1999 will be approved and completed by 2000, the number of operating IOUs owning generation capacity will decrease to 143. Power plant divestitures, discussed in detail in Chapter 6, have also reduced the total number of IOUs owning generation capacity.

The majority of electric utilities are wholly-owned subsidiaries of public utility holding companies.[15] The

Table 4. Comparison of the Number of Investor-Owned Electric Utilities Owning Generation Capacity, 1992, 1998, and 2000

Company Category	1992			1998			2000 (Estimated)		
	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)	Number[a] of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)
Utility that Is a Subsidiary to a Holding Company	113	70	(78%) 422.1	125	68	(83%) 441.0	114	53	(89%) 396.3
Independent Utility	59	–	(22%) 120.3	36	--	(17%) 87.3	29	–	(11%) 49.0
Total	172	70	(100%) 542.4	161	68	(100%) 528.3	143	53	(100%) 445.3

[a]The number of utilities reported here does not match the number of utilities reported in Chapter 2 for the following reasons: (1) these data include IOUs that own power generation capacity, whereas the data reported in Chapter 2 include IOUs that operate power plants; (2) some utilities operate transmission and distribution systems only and are not included here; and (3) these data exclude Alaska and Hawaii.

Notes: • The 2000 data include the effects of pending mergers on consolidation of ownership. It is assumed that all pending mergers that were announced by September 30, 1999 will be completed by 2000. • Also, the 2000 data include the effects of generation asset divestitures on consolidation of ownership. It is assumed that all divestitures where a buyer has been announced as of September 30, 1999 will be completed by 2000. • Holding companies were identified from the following documents: U.S. Securities and Exchange Commission Financial and Corporate Reports, "Holding Companies Registered Under the Public Utility Holding Company Act of 1935 as of October 1, 1995, as of December 1, 1996, and as of June 1, 1998," and "Holding Companies Exempt from the Public Utility Holding Company Act of 1935 Under Section 3(a) (1) and 3(a) (2) Pursuant to Rule 2 Filings or By Order as of August 1, 1995 and as of November 1, 1997."

Sources: Energy Information Administration, Forms EIA-860, "Annual Electric Generator Report, 1992;" EIA-860A, "Annual Electric Generator Report - Utility, 1998;" and EIA-861, "Annual Electric Utility Report, 1992 and 1998."

[14] Because these figures include IOUs that own power generation capacity only, they do not match data in Chapter 2, which discusses the number of utilities that operate power plants. Some utilities own power generation capacity but do not operate a power plant, and some utilities operate power plants but do not own them.

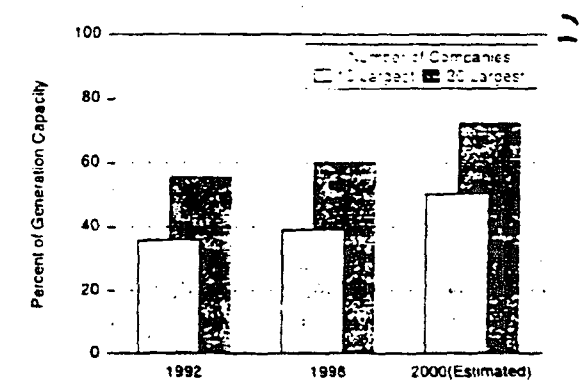
[15] In some cases a holding company will also be a subsidiary of another holding company. The number of holding companies cited in this report refers to the highest level holding company.

affect of mergers on consolidation of the industry is more evident when ownership capacity is aggregated by holding company. In 1992, there were 70 holding companies owning 78 percent of the IOU-held generation capacity (Table 4). By 1998 the number of holding companies decreased to 68, but yet the percent of total IOU-owned capacity increased to 83 percent, primarily because of mergers and acquisitions between IOUs. Assuming that all mergers pending as of September 1999 are completed by 2000, the number of holding companies will decrease to 53, and the generation capacity they own will increase to about 89 percent of the total IOU-owned capacity. The number of holding companies will decrease because most of the pending mergers are between holding companies, which indicates that relatively large companies are becoming even larger.

Although many IOUs that own power generation capacity have merged or have announced plans to merge, the majority of them have not. Of the 104 IOUs (either electric utility holding companies or independent electric utilities) that owned generation capacity in 1998 (see Table 4), 60 (58 percent) have not been involved in a merger since 1992 and have not announced plans to merge. This suggests that even though the merger trend is strong, most IOUs believe consolidation is not necessary to remain competitive in the industry in spite of the fact that those companies choosing to merge are acquiring a larger share of the industry's assets.

The absolute number of companies provides insight into consolidation trends, but concentration of generation capacity ownership is perhaps more indicative of consolidation.[16] As a measure of consolidation of the industry, concentration indicates the extent to which total capacity ownership is dispersed among companies. The data suggest that generation capacity owned by IOUs has been concentrated in the hands of a few companies, and that mergers and acquisitions are increasing the concentration of ownership. In 1992, the 10 largest utilities, ranked according to generation capacity, owned 33 percent of all IOU generation capacity; by 1998 their share had increased to 39 percent, primarily as a result of mergers (Figure 4). Again, assuming that all pending mergers will be completed by 2000, the 10 largest companies' share will increase to about 51 percent. Evidence of consolidation among the 20 largest companies is even more compelling: in 1998 the 20 largest companies owned 60 percent of total IOU generation capacity; by 2000 their share is expected to increase to approximately 73 percent, assuming that all pending mergers are completed.

Figure 4. Concentration of Ownership of Investor-Owned Utility Generating Capacity, 1992, 1998, and 2000



Notes: •The 10 largest companies are public utility holding companies that own one or more operating electric utilities. • The 2000 data assume that all pending mergers as of September 1999 will be completed by year-end 2000. •Capacity owned by subsidiaries of IOUs was not counted when computing the rankings.

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generation Report,1992;" Form EIA-860A, "Annual Electric Generator Report - Utility,1998;" and EIA-861, "Annual Electric Utility Report (1992 and 1998)."

The conclusion suggested by the data is that power generation capacity owned by IOUs is becoming concentrated in companies that are becoming larger through mergers and acquisitions. However, because of power plant divestitures, IOUs, as a whole, will own less of the Nation's power generation capacity in the future. Mergers and acquisitions also result in consolidation of bulk power transmission systems and distribution systems. This trend is not quantified in the report, but examples of it are discussed below.

Ranking of Largest Investor-Owned Electric Utilities

The 10 largest owners of power generation capacity in the United States are public utility holding companies

[16] Concentration of generation capacity does not imply market power or the ability to charge higher prices. Market power and other issues concerning the effects of a merger on competition are reviewed by the Federal Energy Regulatory Commission.

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(Table 5).[17] Presently, Southern Company is the largest, with six electric utility subsidiaries located in the southeastern United States. Southern Company not only has six electric utility subsidiaries, it also owns Southern Energy, an IPP active in the purchase and construction of power plants throughout the United States. As a side note, many public utility holding companies own IPP subsidiary companies that generate and sell power in wholesale markets. The number of IPPs and their share of total generation capacity in the United States are expected to increase.

American Electric Power Company (AEP), the second largest company in 1992, had dropped to third by 1998 because of a merger between Entergy Corporation and Gulf States Utilities. AEP, with eight operating electric utility subsidiaries, is attempting to merge with Central & Southwest Corporation, a large utility holding company with four operating electric utilities. If that merger is approved, the combined company will become the largest IOU holding company in the United States, in terms of power generation capacity.

Two companies, SCE Corporation and Pacific Gas & Electric Corporation, have divested or are in the process of divesting a large portion of their power generation assets. As a result, they have dropped from the list of the 10 largest companies in the 2000 ranking based on ownership of generation capacity. Interestingly, Unicom is also divesting its fossil-fuel generation capacity, representing almost one-half of its total capacity, but plans to hold onto its nuclear power plants. In September 1999 Unicom and Peco Energy announced merger plans. When completed the new company will be the fifth largest IOU in the Nation, and one of the largest producers of electricity using nuclear power in the United States.

Some of these top electric power companies have invested in other energy-related industries, with large investments in natural gas production, pipelines, storage, or gas distribution. Duke Energy Corporation, for example, has embarked on an aggressive growth plan to become a leading energy company and is now one of the largest combined electric power and natural gas companies in the United States.

Table 5. Ranking of the 10 Largest Investor-Owned Companies by Ownership of Generation Capacity, 1992, 1998, and 2000

Company	1992 Ranking	1998 Ranking	2000 (Estimated) Ranking
Southern Company	1	1	2
American Electric Power Company	2	3	[a]1
Unicom (formerly Commonwealth Edison)	3	5	Not in 10 largest
TXU (formerly Texas Utilities Company)	4	4	4
Duke Energy Corporation	5	7	8
Entergy Corporation	6	2	3
FPL Group, Inc. (Florida Power & Light)	7	6	7
SCE Corp. (Southern California Edison)	8	Not in 10 largest	Not in 10 largest
PG&E Corporation (Pacific Gas & Electric)	9	Not in 10 largest	Not in 10 largest
Reliant Energy (formerly Houston Industries)	10	9	10
New Century Energies	Did not exist	Not in 10 largest	[b]8
First Energy	Did not exist	8	10
Carolina Power & Light/Florida Progress[c]	Did not exist	Did not exist	6
Dominion Resources, Inc.	Not in 10 largest	10	Not in 10 largest
Unicom/Peco	Did not exist	Did not exist	5
Xcel Energy (New Century Energies/Northern States Power)[d]	Did not exist	Did not exist	9

[a] Assumes merger with Central & Southwest Corp. will be completed by 2000.
[b] Assumes merger with Nothern States Power will be completed by 2000.
[c] Assumes merger will be completed by 2000.
[d] Assumes merger between New Century Energies and Northern States Power will be completed by 2000.
Notes: •The 10 largest companies are public utility holding companies that own one or more operating electric utilities.
•Capacity owned by IPP subsidiaries of these companies was not counted in computing the rankings.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

[17] Other criteria for ranking these companies (i.e., total assets) would produce significantly different results; some of these companies would drop out of the 10-largest list.

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