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

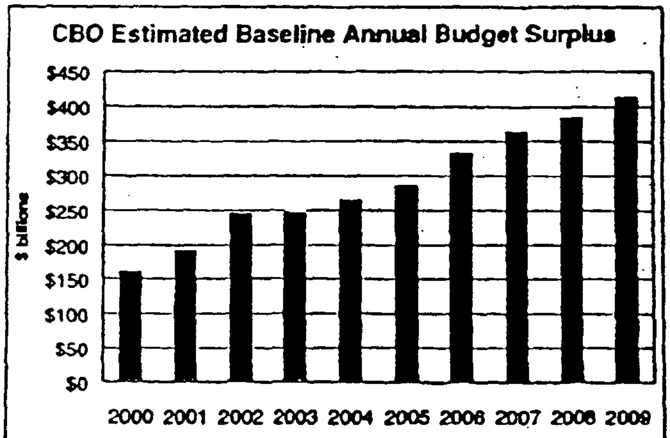
Repeal Deficit Reduction Fuel Taxes

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.



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.

The Importance of Fuel Diversity in Establishing a National Energy Policy and a Sound Climate Change Strategy

The U.S. economy is highly dependent on affordable electricity. Since 1970, electricity growth has closely tracked the rise in GDP. To meet increased demand and to offset retirements of existing power plants, the Department of Energy forecasts that 1,310 new power plants – with 393 gigawatts of capacity – will be needed by 2020.[1] A sound national energy policy is needed to continue to ensure the affordability and reliability of electricity, and to meet future energy demands.

The Coal-Based Generation Stakeholders (CBGS) group believes that fuel diversity – coal, natural gas, nuclear energy, oil, hydropower and other renewables, to generate electricity – must be maintained as a matter of national energy policy and national security. An energy policy that maintains fuel diversity can appropriately balance continued utilization of coal, the most essential fuel for reliable and affordable electricity, with a sensitivity to the climate change issue that reflects both economic and environmental objectives.[2]

The industries that comprise CBGS have long supported voluntary, flexible, cost-effective and inclusive approaches to reducing greenhouse gases.[3] For example, under the Climate Challenge program, the electric utility industry was projected to reduce 174 million metric tons of carbon dioxide (CO_2)-equivalent greenhouse gases in 2000. The electric power industry is currently developing a voluntary climate initiative that would serve as an extension of the Climate Challenge program. The industry expects to partner with the federal government – particularly the Department of Energy – and other industries to pursue approaches to further reducing greenhouse gases. This initiative will reduce greenhouse gases in the near term, and promote a technology research, development and deployment (R, D & D) program that will lead to the development of cost-effective options to reduce greenhouse gases.

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[1] Energy Information Administration (EIA), "Annual Energy Outlook 2001 with Projections to 2020" (Dec. 2000).

[2] Coal-based generation is increasingly clean. Since 1970, coal-based electric generation has increased 234 percent and coal use in power plants has increased 270 percent, yet criteria pollutant emissions have steadily declined. EIA, "Annual Energy Review 1999."

[3] "Voluntary" recognizes that the climate change issue merits policy responses that explore economically sustainable measures should any legally binding agreement to address greenhouse gases be adopted. Full "flexibility" encompasses emissions trading, project-based offsets, forestry and soils projects, and banking, which will be critical in the event of any domestic or international agreement. "Inclusive" encompasses all greenhouse gases; all sources and sinks; and all locations, domestic and international. "Reduce" means reduce, avoid, sequester or otherwise mitigate greenhouse gases, whether domestically or internationally.

CBGS supports continued scientific research to evaluate if human activity is adversely affecting the climate, and, if so, to evaluate the causes, costs, policies and adaptation strategies to address possible solutions. Consistent with the President's March 13 letter to several Senators, CBGS opposes ratification of the Kyoto Protocol because it would cause serious harm to the U.S. economy and lacks binding commitments for all nations. Also consistent with the President's letter, CBGS strongly opposes regulation of CO_2 or any other greenhouse gas as a pollutant under the Clean Air Act or other legislation.

Because there is currently no cost-effective control technology for greenhouse gas emissions, compliance with stringent, mandatory targets and timetables such as those contained in the Protocol would cause massive fuel switching in the electric utility industry from coal to natural gas,[4] which would be enormously expensive and dramatically increase electricity prices,[5] and which would further exacerbate the fuel diversity issue. A Kyoto Protocol-type scenario would also raise serious problems in natural gas supply, prices and infrastructure, and would cause significant job losses in CBGS industries and among our suppliers. Stringent targets and timetables other than those contained in the Protocol also could be harmful to our nation's economy and energy policies. Moreover, they could have a chilling effect on badly needed investment in new coal-based generation because of a legitimate concern that such investments would become stranded in the event legally binding regulations were imposed in the future.

As currently envisioned, a sound voluntary climate initiative would consist of three major elements:

1. In the short term, the climate initiative is expected to achieve credible, verifiable emission reductions or offsets of greenhouse gases facilitated by certain policies and incentives from the federal government, including those that encourage full flexibility for emission credit and trading programs.

2. Further reductions of greenhouse gases in the medium to long term would result from the development and application of more energy-efficient, cost-effective electricity supply options, such as clean coal technology and renewables, that allow for a reliable and affordable supply of energy.

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[4] See, *e.g.*, the reference study that demonstrates that under a Kyoto Protocol-type scenario, coal would decline from 50 percent of electric generation to as low as 13 percent in 2010, while natural gas would rise from 25 percent to 50 percent in the same time frame. Research Data International, Inc., U.S. Gas and Power Supply under the Kyoto Protocol, Vol. I at 1-9 (Sept. 1999).

[5] A recent EIA report (which actually understates costs because mercury has not yet been analyzed) found that reductions in sulfur dioxide, nitrogen oxides and CO_2 consistent with recent legislative proposals would increase electricity prices by 17-33 percent in 2005, and by 30-43 percent in 2010. EIA, Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides and Carbon Dioxide xvii, 27 (Dec. 2000). The bulk of the cost increases are due to CO_2 restrictions.

3. A climate technology R, D & D program is needed to ensure that cost-effective technologies are developed in the long term. This program should complement overall U.S. energy policy and the Framework Convention on Climate Change.

   - In accordance with legislation introduced in the 106^{th} Congress – such as S. 882, S. 1776, S. 1777 and S. 3253 – and public-private studies,[6] the R, D & D program could focus on 1) advanced technologies in electric generation and transportation, 2) cost-effective direct carbon capture and removal from powerplant and other emission sources, and 3) carbon sequestration in natural "sinks" such as forests, soils and oceans.

   - Two program goals could be to 1) fast track such climate technologies to market, and 2) promote export of such technologies overseas, particularly to developing countries such as China and India that could greatly benefit from more energy-efficient electric generation technology.

   - In partnership with the federal government, the climate initiative would be expected to adequately fund the climate technology R, D & D program and to provide appropriate financial incentives, with periodic reassessment. Industry partners that install new climate technologies would be interested in recouping any substantial investments over a reasonable period of time.

The climate initiative should be consistent with government policies that encourage full flexibility, both domestically and internationally, in emissions trading, project-based offsets, forestry and soils projects, and banking. Financial and policy-oriented government incentives should be explored as a means to jump start credit and trading programs, offset projects, and the climate technology program.

Development of a voluntary climate initiative presents an opportunity not only for innovative emission reduction programs, but also for the inclusion of a broader number of partners involved in the life cycle of coal-based generation. For example, credit could be given to environmental improvements from extracting coal at the mine and delivering it to the generator.

CBGS believes that a climate change strategy premised on a voluntary climate initiative would achieve both environmental and economic objectives, and would help maintain fuel diversity. The strategy would reduce greenhouse gases in the short term as technological responses are developed for long-term availability, all the while maintaining the viability of coal as a vital component of electric generation. In short, environmental policy would complement energy policy, which is consistent with the President's goal of ensuring that global climate change issues are addressed "in the context of a national energy policy that protects our environment, consumers, and economy."

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[6] See, *e.g.*, Battelle's Global Energy Technology Strategy – Addressing Climate Change (2000).

New Source Review

Description: The Clean Air Act imposes stringent "new source" control technology requirements on new units, and on existing sources if they are extensively modified. In 1996, EPA reinterpreted the new source review (NSR) program in a way that redefines when an existing source is considered to have been "modified," and issued a proposed rule consistent with this reinterpretation. EPA's approach presents an obstacle to efficiency improvement projects, safe operations and reliable generation, which is inconsistent with a sound national energy policy and the need to continue to ensure affordable and reliable electricity.

In addition, EPA has initiated litigation against over 40 investor owned power plants and 10 TVA plants to force installation of new control technology on plants that EPA alleges have been modified. EPA's litigation and enforcement strategy is inconsistent with past interpretations and implementation of the NSR program.

Status: EPA has not yet finalized its proposed NSR rule, but, on December 12, 2000, the agency published a *Federal Register* notice regarding a Detroit Edison project that has national implications because it interprets the existing NSR rule to cover reliability and efficiency improvement projects. In that notice, EPA claims, contrary to the language of the current NSR modification rules, that electric utility sources must get state (or EPA) approval before undertaking necessary maintenance, repair, and replacement projects. An administrative petition has been filed requesting that the Administrator reconsider the Detroit Edison notice and confirm that EPA's 1992 WEPCo rule and pre-1996 policies remain in effect. Regarding ongoing EPA enforcement efforts, additional notices of violation and lawsuits are expected unless policy changes are initiated.

Key Issues/Decisions: How can the NSR program be reformed to complement national energy policy objectives, and to avoid being an impediment to efficient, safe and reliable plant operations?

Actions Requested: The Administrator should grant the Detroit Edison petition and publish notice of this action in the *Federal Register*. In that notice, EPA should confirm that the WEPCo rule and pre-1996 policies remain in effect pending a reevaluation of regulatory and policy options. The Administrator also should initiate true NSR reform. The industry is ready to work cooperatively with EPA on this effort.

Harmonizing Ozone Rules Under the Clean Air Act

Description: In January 2000, EPA issued its Clean Air Act "section 126" rule, requiring power plants and some industrial sources in 13 states to make significant cuts in nitrogen oxide (NO_x) emissions to help four states (Connecticut, Massachusetts, New York and Pennsylvania, all of which filed petitions under section 126 requesting source-specific reductions) reduce their ozone levels. EPA insists targeted sources must comply by May 1, 2003, even though this date would make compliance very difficult because of the lead time needed to engineer, purchase, install and test emission control equipment. More importantly, this deadline conflicts with a court-ordered May 31, 2004 compliance date for EPA's "SIP call" rule. The SIP call requires NO_x reductions from power plants and some other sources in 22 eastern states, including those subject to the section 126 rule, and will necessitate capital costs in excess of $13 billion and associated O&M costs of at least this much. The North American Electric Reliability Council has issued a study concluding that pending NO_x reductions will require many Midwestern coal-fired plants to retrofit with sophisticated new technologies, thus significantly increasing planned maintenance outages (on top of projected low reserves), and hence some reliability risks in the next several years. NO_x controls are imminent, but it is imperative that reductions occur in the least burdensome and most economically responsible manner possible.

The section 126 rule also removes state flexibility to decide which sources to control and by how much. Many states want the section 126 rule deadline to be the same as the SIP call compliance date, or made inapplicable for states that implement the SIP call. Some northeast states, companies and environmental groups want the section 126 rule and its deadline retained. Congressional appropriators have repeatedly urged EPA to harmonize the section 126 rule and SIP call implementation dates.

Status: The Supreme Court denied an appeal by parties challenging the underlying merits of the SIP call rule; however, this did not affect the May 31, 2004 compliance date. Legal challenges to the section 126 rule are pending in the D.C. Circuit Court of Appeals. A decision is expected by spring 2001, but may not resolve the SIP call/section 126 conflict. In the interim, states face significant uncertainty in developing implementation plans. Similarly, regulatory certainty is *critical* to companies, yet affected sources currently do not know which deadline and what controls apply.

Key Issue/Decision: The section 126 and SIP call rules must be harmonized.

Actions Requested: Congress clearly intended that the SIP call process would drive state compliance with Clean Air Act emission reduction requirements. The section 126 rule explicitly provides the Administrator authority to deny, or withdraw prior approval of, any section 126 petition targeting sources in a state where EPA approves that particular state's implementation plan. The Administrator should clarify immediately that the SIP call implementation schedule is controlling and that NO_X reductions must be made by the May 31, 2004 compliance date.

Regulation of Mercury Emissions from Coal- and Oil-Based Power Plants

Description: On December 14, 2000, EPA made a "regulatory determination" under the Clean Air Act 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, and EPA is scheduled to issue a proposed rule in late 2003 and a final rule in late 2004. EPA has estimated costs of a mercury control program to be about $5 billion annually, while DOE and others have estimated significantly higher costs. Members of Congress from both parties have raised concerns about the adverse consequences of mercury regulation, including impacts to the fish industry. A stringent mercury control program could impact fuel diversity and coal-based generation in the same manner as a mandatory CO_2 reduction program.

Unfortunately, the language of the regulatory determination could severely limit the Administrator's future options. EPA's designation of a specific regulatory approach -- even though the regulatory determination is not a formal rule -- means that *new* coal- and oil-based plants, as well as *existing* coal- and oil-based plants that are "reconstructed," will be regulated immediately in accordance with the stringent, source-by-source control program called for in the determination. Ironically, this harsh impact occurs at the outset of a multi-year regulatory process during which EPA will be attempting to establish a scientific record that justifies a stringent mercury control rule. Note that a decision today to modify the regulatory determination would neither affect the regulatory schedule, nor hinder ongoing mercury-related health effects, fate-and-transport, and emission reduction technology research critical to making sound regulatory decisions.

Status: EPA's regulatory determination was published in the *Federal Register* on December 20. The agency indicated it did not want more input on the determination, instead noting that a proposed rule will be subject to public review and comment. Legal challenges have been filed in the D.C. Circuit by the utility industry. An administrative Petition for Reconsideration also has been filed with EPA, in effect requesting the agency to withdraw that portion of the regulatory determination that prescribes a specific control program and immediately impacts new and reconstructed units.

Key Issues/Decisions: Electric utilities are explicitly treated differently under the CAA than other major sources of HAPs, in that EPA's assessment of power plants "shall" address "alternative control strategies." However, language in EPA's determination sets in motion the regulation of mercury emissions under a strict, source-by-source control program that eliminates flexibility and use of market mechanisms. The Administrator should avoid this unnecessary limitation on possible regulatory options.

Actions Requested: The Administrator should (1) reconsider that portion of the regulatory determination that prescribes a specific control program and immediately impacts new and reconstructed units; (2) clarify that EPA does not intend to limit regulatory options when proposing a rule; and (3) clarify further that the regulatory determination applies only to mercury and not other HAPs.

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

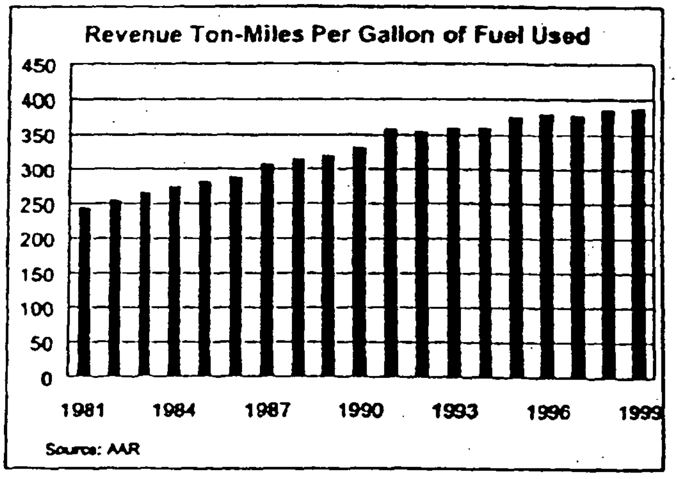
In April 2000, the Clinton Administration announced the creation of the "21st Century Truck Initiative," a public-private research partnership involving many of the nation's largest heavy-duty engine and truck companies; the U.S. Departments of Defense, Energy, and Transportation; and the Environmental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

- 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.



COAL-BASED GENERATION STAKEHOLDERS

March 16, 2001

Vice President Richard B. Cheney
The White House
Washington, DC 20500

Dear Mr. Vice President:

We are addressing this letter to you in your capacity as chairman of the White House Energy Policy Development Task Force. We co-chair the Coal-Based Generation Stakeholders Group, an informal coalition of utilities, coal producers and railroads whose companies represent nearly one million employees and $275 billion in combined revenues. The coalition is working together to promote a balanced energy policy that recognizes the critical role coal-based electric generation plays in America's national and economic security.

We applaud the announcement this week that the Administration did not support regulation of carbon dioxide as an air pollutant under the Clean Air Act; the position reflects one of our central guiding principals. Over the last eight years, a number of environmental and energy policies were adopted that placed enormous constraints on the continued viability of coal-based generation. The recent price volatility and reliability problems in our electricity and natural gas markets are symptomatic of a larger energy crisis in the United States and in part are the result of a loss of fuel diversity in our energy mix engendered by those policies.

Our coalition is committed to being part of the clean air solution by continuously improving the environmental performance of coal-based generation through increased public-private funding and incentives for development and deployment of advanced clean coal technologies. The group also seeks environmental policies that: 1) rely on sound science and demonstrable public health benefits, 2) consider fuel costs and security and reliability of electric supplies, 3) establish practical compliance schedules, 4) provide reasonable certainty for investments in environmental controls and new generating facilities; and 5) give states appropriate flexibility in implementing Clean Air Act policies.

Enclosed are a set of briefing papers covering the major issues that we have discussed with your Administration's representatives, including recommendations on establishing a robust, voluntary CO2 reduction program, reforming EPA's New Source Review process, establishing consistent NOx standards and timetables, and developing a more flexible and cost-effective Mercury rulemaking.

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

Sincerely,

Bill McCormick

William T. McCormick, Jr.
Chairman and Chief Executive Officer
CMS Energy

Irl Engelhardt

Irl F. Engelhardt
Chairman and Chief Executive Officer
Peabody Group

Enclosure

cc: The Honorable Spencer Abraham
The Honorable Donald Evans
Mr. Lawrence Lindsey
Mr. Andrew Lundquist

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SIGNED COPY

THE NATIONAL MINING ASSOCIATION
AND
THE ASSOCIATION OF AMERICAN RAILROADS
MEMORANDUM OF UNDERSTANDING
IN REGARD TO RAILROAD COAL TRANSPORTATION

I. INTRODUCTION

The National Mining Association, hereinafter referred to as "NMA", the Association of American Railroads, hereinafter referred to as "AAR", and those members of the AAR and the NMA who have subscribed to this memorandum of understanding express their mutual agreement and acceptance of the Rail/Coal Communication/Dispute Resolution Process, which is set forth herein.

NMA and AAR realize that abundant coal reserves mined in the United States represent a strategic resource required to fuel the generation of electricity and to furnish an important feedstock for other purposes, and that U.S. coal exports are significant contributors toward improving the U.S. balance of trade with other countries that are coal consumers.

NMA and AAR recognize that the coal industry must rely on dependable, efficient railroad services for distribution of coal produced in the eastern and western states, and that coal traffic represents a highly important element of total railroad freight carried by the railroads and is important to the economic health of the railroads.

NMA and AAR further recognize that the rail industry must rely upon a reliable and adequate supply of coal, equipment and mining infrastructure in order to provide railroad coal customers with efficient service.

II. PURPOSE

This agreement by and between NMA and AAR is entered in for the purpose of establishing a Rail/Coal Communication/Dispute Resolution Process, which will seek inter-industry understanding and resolution of issues which may arise with regard to the adequacy and reliability of railroad and coal company services required for coal shipments from mines to power plants and other coal-consuming facilities, and to inland and coastal ports, in order to supply U.S. coal to domestic and foreign markets. The process will only consider matters which involve providing and utilizing transportation services for coal shipments, and will not discuss transportation rates, costs, or other charges for rail traffic services.

III. STRUCTURE

A. Joint Policy Committee

A Joint Policy Committee shall be created, comprised of six members consisting of the Chief Executive Officers ("CEO") of the NMA, the AAR, two members of the AAR (to be designated by the AAR), and two members of the NMA (to be designated by the NMA). It shall meet annually, or at any other time, at the request of a member of the Committee, to discuss policy issues of industry-wide application relating to the rail transportation of coal. The CEOs of all other AAR and NMA members will also be invited to attend and fully participate in the annual Committee meeting. The Joint Policy Committee shall not have authority to set rates or charges or reach any agreement relating to rate related matters. The annual meetings will be alternately hosted by the AAR and the NMA.

B. Joint Coal Logistics Committee

A Joint Coal Logistics Committee shall be created, comprised of ten members consisting of four railroad coal marketing vice presidents (to be designated by the AAR), four vice presidents of members of the NMA who are responsible for rail transportation within their respective organizations (to be designated by the NMA), and one representative each from the AAR and the NMA. It shall meet semi-annually, or at any other time, at the request of a member of the Committee, to examine, and if applicable, make non-binding recommendations regarding industry-wide issues relating to rail transportation service, efficiency and deployment of assets. The Joint Coal Logistics Committee shall not have authority to set rates or charges or reach any agreement relating to rate related matters. Each semi-annual meeting will be scheduled to allow for in-depth examination of rail coal transportation issues. The meetings will be alternately hosted by the AAR and the NMA.

The Joint Coal Logistics Committee will elect a chairman from its members. The chairman, in alternate years, will be a member of the NMA delegation or the AAR delegation serving on the Committee. The presidents of NMA and AAR will identify matters for consideration by the Committee during its semi-annual or special meetings. The Committee will act as an advisory body only, with the view of providing professional expertise on matters it considers, and of communicating with the association presidents and the Joint Policy Committee on methods for improving both rail service and coal supply reliability and adequacy to overcome problems that may arise with regard to coal shipments on a nationwide or a regional venue.

IV. DISPUTE RESOLUTION PROCESS

A. In the event of disputes between a member of the AAR and a member of the NMA who subscribe to this agreement, those members consent to participate in a dispute resolution process. The goal of this process will be to enable the parties to develop a voluntary, mutually acceptable resolution to their dispute.

B. In the event of disputes, prior to invoking this dispute resolution process AAR and NMA members subscribing to this agreement agree to employ their best efforts to resolve differences through expanded communications and good faith negotiations between the parties involved.

C. If mutual discussions between AAR and NMA members who have subscribed to this agreement do not result in dispute resolution, both parties shall advise the CEOs of their respective organizations of their difficulties. Either CEO may then submit a written request to the CEOs of both the AAR and the NMA to review the dispute.

D. Upon receipt of a request for review, the CEOs of the AAR and the NMA will initiate the following dispute resolution process.

1. Step 1. Convene a panel consisting of the CEOs of the AAR, the NMA and a representative of each organization involved in the dispute. The dispute resolution shall be conducted via informal non-binding meeting or meetings among the panel members in which they will seek resolution of the dispute.

2. Step 2. If the dispute cannot be resolved by the panel convened in Step 1, and if both association CEOs agree, then the matter will be presented to a panel consisting of the

CEOs of the companies involved and the association CEOs. This meeting will seek to develop a consensus on recommended actions among the participants.

E. The dispute resolution process shall be continued until the matters in dispute are resolved or the panel members make a finding that there is no possibility of settlement through the dispute resolution process. All matters relating to a dispute resolution process involving a specific dispute shall be treated as confidential, including the convening of a panel to review such dispute. No party to the process shall disclose to the public that a dispute resolution process is ongoing. Statements, notes, and all records associated with the dispute resolution process shall be treated as confidential and privileged against use in any other proceeding relating to the dispute. Any notes taken by persons during the process shall be destroyed at the conclusion of the process, except for the notes of any final agreement reached by the parties.

V. TERM

This memorandum of understanding shall be effective as of the date executed by both the NMA and the AAR and shall remain in effect through and including December 31, 2000.

The parties agree to the policies, principles and procedures stated herein. Individual members of the NMA and the AAR will indicate their acceptance of this memorandum of understanding by executing a separate document indicating their agreement to subscribe to and be bound by the terms and conditions of this memorandum of understanding.

NATIONAL MINING ASSOCIATION　　ASSOCIATION OF AMERICAN RAILROADS

Richard L. Lawson

12/1/99

Western Independent Refiners Association

Impacts of EPA Regulation

Small Refiners Are Key

- WIRA represents refiners with fewer than 1,500 employees and less than 155,000 barrels per day total capacity. WIRA members produce a full slate of petroleum products including everything from gasoline, diesel and jet fuels to asphalt, lube oil and specialty petroleum products.
- Today, approximately 124 refineries are operating in this country. About 25 percent are small, independent refiners. Small business refiners are primarily owned by U.S. citizens, including privately held businesses and one farmer cooperative.
- Small independent refineries employ thousands of people and each company pays millions of dollars in taxes, even after excluding income taxes.
- In addition to maintaining competition, small and independent refiners often supply other petroleum products not otherwise available in certain areas. For example, small refiners manufacture 100 percent of California's grade 80-aviation fuel, aliphatic solvents, and JP-4 jet fuel. Small refiners also manufacture 100 percent of the asphalt produced in southern California and much of the off-road diesel fuel. Half of the diesel fuel produced in the San Joaquin Valley, California's farm belt, is refined by small refiners.

Refining Capacity is at a Maximum

- As Secretary of Energy Spencer Abraham noted in recent comments to the United States Chamber of Commerce, the number of American refineries has been cut in half since 1980. Many of these were small business refiners unable to meet the challenges of poor refining margins and expensive regulations. Meanwhile, no new refinery has been built in the United States in over 25 years and regulatory requirements limit the ability of existing refineries to expand capacity.
- Government regulations require the production of more than 15 types of gasoline. Existing refineries are operating at capacity resulting in more frequent unplanned shutdowns. Every small refiner forced from the marketplace increases our vulnerability. Given the foregoing, one must agree with Secretary Abraham that we "have a refining industry strained to capacity, leaving us dangerously vulnerable to regional supply disruptions and price spikes."

Federal Regulations Burden Small Refiners Disproportionately

- On January 18, 2001, the EPA published new regulations, which create **new standards for levels of sulfur in highway diesel fuel** beginning in June 2006. Under the new regulations, refiners must meet a stringent new standard of 15 parts per million sulfur limit for most on-road diesel volume ("Ultra Low Sulfur Diesel Fuel").
  - Small refiners produce about four percent of the Nation's diesel fuel and in some regions produce over half of the diesel fuel.

- Access to crude oil is an ongoing challenge, as large companies merge and the remaining mega-companies are not consistently willing to supply small refiners.
- Wastewater treatment controls and stationary source air quality controls have become increasingly stringent, thus raising costs for small refiners.

The challenges facing small refiners continue. Not only must they compete head to head with some of the largest companies on the planet, but also they must comply with increasingly stringent government regulations. Of most concern: on January 18, 2001, the EPA published new regulations, which create **new standards for levels of sulfur in highway diesel fuel** beginning in June, 2006. Under the new regulations, refiners must meet a stringent new standard of 15 parts per million sulfur limit for most on-road diesel volume ("Ultra Low Sulfur Diesel Fuel"). Small refiners produce about four percent of the Nation's diesel fuel and in some regions produce over half of the diesel fuel. In the final rule, EPA stated regarding the diesel sulfur standards "that small business refiners would likely experience a significant and disproportionate financial hardship in reaching the objectives of our diesel fuel sulfur program." In the final rule, EPA agreed with the final Small Business Administration report regarding the diesel sulfur standards "that small business refiners would likely experience a significant and disproportionate financial hardship in reaching the objectives of our diesel fuel sulfur program." However, EPA has made no provision to assist small business refiners in financing the mandated capital expenditures.

The new regulations also will make it even less likely that new refineries will ever be built. With the exception of one small topping facility in Alaska, no new refinery has been built in the United States for almost 20 years. Existing facilities are operating at full sustainable capacity. Operational demands imposed by the new regulations will result in a reduction of on-road diesel production. At the same time, U.S. consumer demand for diesel fuel, as forecast by the Energy Information Administration, is expected to grow by 6.5 percent between now and 2007. If small business refiners are eliminated from diesel production, supply shortages will become even more likely. Therefore, it is important to seek methods to reimburse small business refiners for their costs in meeting these new government imposed mandates, which endanger their long-term economic viability.

EPA estimates that small business refiners will incur average capital costs of $14 million per facility to meet the new diesel regulations. For some facilities, the cost will be substantially more.

In addition, costs to produce low-sulfur gasoline and to comply with other regulations will add significantly to capital requirements in approximately the same time frame. Such capital investments are significantly beyond the financial capability of facilities operated by small business refiners, whose total investment is dwarfed by these requirements. On top of the initial required capital expenditures, the related increases in operating costs could equal or exceed the refineries' historical annual profits, and thus, imperil the viability of these important US businesses.

While WIRA does not oppose the regulation, and is fully committed to compliance, we believe that national energy policy should take into account the importance of the small refiners and should include proposals for mitigating the impact of this regulation. Without such provisions, some small business refiners will shut down and all will struggle to meet the mandated expenditures. Such a policy ignores the important role of the small business refiner in the U.S. energy market. The result of such a policy will have serious consequences for our country.

Conclusion: U.S. Government Energy Policy Should Recognize the Role of the Small Refiner

The challenges to small business refiners, including the need for mitigation for the impact of otherwise appropriate environmental policies, should be recognized by the Congress and should be addressed in overall U.S. energy policy. If this does not occur, and small refiners go out of business, the competitive fabric of the U.S. oil and gas industry will be irreparably damaged.

Thank you for your consideration of these important comments.

STATEMENT OF CRAIG MOYER,
MANATT, PHELPS & PHILLIPS
SUBMITTED ON BEHALF OF
THE WESTERN INDEPENDENT REFINERS ASSOCIATION
BEFORE THE HOUSE SUBCOMMITTEE ON ENERGY AND AIR QUALITY
MARCH 30, 2001

On behalf of the Western Independent Refiners Association (WIRA), in my capacity as counsel for WIRA, I am pleased to provide this statement for the record providing an overview of the current challenges facing small business refiners (refiners with fewer than 1500 employees and less than 155,000 barrels per day total capacity). WIRA is a trade association of small and independent refineries on the West Coast. At this time, ten small independent refineries continue to operate on the West Coast, nine in California and one in Tacoma, Washington. In California, these refineries are located in each of the three refining areas within California. One is located in the San Francisco Bay area. One is located in the Bakersfield area of the Southern San Joaquin Valley and the remaining facilities operate in the Los Angeles Basin. Small independent refineries employ thousands of people and each company pays millions of dollars in taxes, even after excluding income taxes. WIRA members produce a full slate of petroleum products including everything from gasoline, diesel fuel and jet fuel to asphalt, lube oil and specialty petroleum products. At this time, when it so clear that all domestic energy sources should remain viable and that no domestic source should be overlooked, I believe that it is important for this Subcommittee to understand the role of small refiners to the energy supply of our nation.

The Pro-competitive Role of the Small Refiners

Small and independent refiners have long been recognized as an important competitive force in the refining sector. Individually, each small refiner represents a relatively small share of the petroleum product marketplace. Cumulatively, however, their impact is substantial. Their pricing competition pressures the larger integrated companies to lower prices to the consuming public. Without that competition pressure, consumers will pay more. For example, in early 1991, Amoco shut down a 40,000 barrels per day refinery in Casper, Wyoming, and gasoline prices jumped almost 10 cents per gallon. In California, the Attorney General concluded that after five small refiners shut down because they could not manufacture California's cleaner burning gasoline, the loss of competition cost consumers hundreds of millions of dollars. Through experience, we know that when small refiners leave the marketplace, prices go up and consumers suffer.

Congress and many agencies, including the Environmental Protection Agency ("EPA") and the California Air Resources Board ("CARB"), have long recognized the importance of the independent refining sector to maintaining a competitive market for petroleum products. For example, after EPA promulgated rules limiting the sulfur content of diesel fuel to 500 parts per million effective October 1, 1993, Congress recognized the implications of this rule on small diesel refiners and authorized the issuance of acid rain credits to small diesel refiners pursuant to Section 410 (h) of the

1990 Clear Air Act amendments. Because of the important pro-competitive impact of small refiners, CARB, an agency that has promulgated perhaps the most stringent fuels regulations in the Country, has provided separate treatment for small refiners in virtually every fuels regulation it has passed since 1988. In its two most recent fuels rulemakings, EPA has authorized separate treatment for small business refiners, as well. Even the South Coast Air Quality Management District, an agency leading the nation and perhaps the world, in stringent air quality regulations, authorized separate treatment for small refiners in its recently promulgated Rule 431.1 regulating diesel fuel.

In addition to maintaining competition, small and independent refiners often supply other petroleum products not otherwise available in certain areas. For example, small refiners manufacture 100 percent of California's grade 80-aviation fuel, aliphatic solvents, and JP-4 jet fuel. Small refiners also manufacture 100 percent of the asphalt produced in southern California and much of the off-road diesel fuel. Half of the diesel fuel produced in the San Joaquin Valley, California's farm belt, is refined by small refiners.

Small business refiners also fill a critical national security function. For example, in 1998 and 1999, small business refiners provided almost 20 percent of the jet fuel used by U.S. military bases. This adds up to almost 500 million gallons of jet fuel supplied each year under defense contracts between the government and small business refiners.

Challenges Facing the Industry

Today, approximately 124 refineries are operating in this country. About 25 percent are small, independent refiners. Small business refiners are primarily owned by U.S. citizens including privately held businesses and one farmer cooperative.

As Secretary of Energy Spencer Abraham noted in recent comments to the United States Chamber of Commerce, the number of American refineries has been cut in half since 1980. Many of these were small business refiners unable to meet the challenges of poor refining margins and expensive regulations. Meanwhile, no new refinery has been built in the United States in over 25 years and regulatory requirements limit the ability of existing refineries to expand capacity. Government regulations require the production of more than 15 types of gasoline. Existing refineries are operating at capacity resulting in more frequent unplanned shutdowns. Every small refiner forced from the marketplace increases our vulnerability. Given the foregoing, one must agree with Secretary Abraham that we "have a refining industry strained to capacity, leaving us dangerously vulnerable to regional supply disruptions and price spikes."

Some of the major challenges facing small refiners in today's market include:

- Small refiners are large users of electricity and natural gas. The remarkably high prices of these inputs are affecting the small refiners.
- The phase out of MTBE as an oxygenate will lead to increased costs as reformulations are required.

Martin, Adrienne

From: Anderson, Margot
Sent: Monday, April 23, 2001 5:15 PM
To: 'Charles Smith (E-mail)'; 'Joan O'Callahan (E-mail)'
Subject: TWO (only 2) comments on chapter 9

Joan and Charlie,

b5

Thanks,

Margot

2279

Martin, Adrienne

From:	Anderson, Margot
Sent:	Monday, March 26, 2001 12:11 PM
To:	Zimmerman, MaryBeth; Breed, William
Subject:	FW: questions
Importance:	High

Joe has some questions on the policy options list.

Mary Beth, can you answer 1 & 2
Bill, can you answer 3,4,5?

ASAP

Margot

-----Original Message-----

From:	Kelliher, Joseph
Sent:	Monday, March 26, 2001 10:48 AM
To:	Anderson, Margot
Subject:	questions
Importance:	High

A few questions to help winnow down our list even more --

b5

2280

Martin, Adrienne b5

From: Kelliher, Joseph
Sent: Thursday, April 12, 2001 8:24 PM
To: Anderson, Margot
Subject: RE: VP Task Force

-----Original Message-----
From: Anderson, Margot
Sent: Thursday, April 12, 2001 12:37 PM
To: Kolevar, Kevin; Kelliher, Joseph
Subject: RE: VP Task Force

Kevin,

Margot

-----Original Message-----
From: Kolevar, Kevin
Sent: Thursday, April 12, 2001 12:04 PM
To: Kelliher, Joseph; Anderson, Margot
Subject: RE: VP Task Force

I am familiar with the first but not the second.

Margot, can you help me on that?

-----Original Message-----
From: Kelliher, Joseph
Sent: Thursday, April 12, 2001 10:49 AM
To: Kolevar, Kevin
Subject: VP Task Force

We have some assignments with respect to next week's meeting. Can you handle two of them? First, working with EPA and Ag on an RFG recommendation. Second, working with EPA on a NSR recommendation. Can you contact EPA on these issues? Are you familiar with NSR? Please work with Margot on these. Thanks.

2281

Martin, Adrienne

From:	Anderson, Margot
Sent:	Wednesday, March 21, 2001 7:07 PM
To:	'Charles_M._Smith@ovp.eop.gov%internet'
Subject:	RE: comments on graphics

Charlie,

Just a reminder but I still don't have this.

Margot

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Wednesday, March 21, 2001 2:19 PM
To: Anderson, Margot
Subject: comments on graphics

Below are the comments/suggestions re. graphics for the interim report

---

Following is my feedback on DOI's suggestions for graphics.

b5

FYI,
I'll be in tomorrow morning, but out for the rest of the day. If you think you'll need me for a meeting on graphics early next week, please let me know
ASAP, since I currently have afternoon meetings scheduled for Mondav and Tuesday afternoons (which I can reschedule with sufficient notice).

b5

2324

b5

2325

DOE026-0048

Martin, Adrienne

From: Anderson, Margot
Sent: Thursday, March 08, 2001 12:02 PM
To: Carter, Douglas
Subject: RE: Multipollutant strategies & CO2

Thanks. Doug. PO looked at this too. Will send out what I send to Kyle.

-----Original Message-----
From: Carter, Douglas
Sent: Wednesday, March 07, 2001 5:35 PM
To: Anderson, Margot
Cc: Kripowicz, Robert
Subject: Multipollutant strategies & CO2

Margot -

Bob Kripowicz asked me for a quick review of EIA's December 2000 report. That review (1-page) is attached, fyi.

<< File: EIA-3Pol.wpd >>

Doug Carter (FE-26)
US DOE
Washington, DC 20585
202-586-9684

(This email uses 100% recycled electrons.)

2326

DOE026-0049

Martin, Adrienne

From: Carter, Douglas
Sent: Wednesday, March 07, 2001 5:35 PM
To: Anderson, Margot
Cc: Kripowicz, Robert
Subject: Multipollutant strategies & CO2

Margot -

Bob Kripowicz asked me for a quick review of EIA's December 2000
That review (1-page) is attached, fyi.

b5

Bob asked that I share these views with you, given your likely involvement in future activities related
Please call if you wish to discuss.

EIA-3Pol.wpd

Doug Carter (FE-26)
US DOE
Washington, DC 20585
202-586-9684

[This email uses 100% recycled electrons.]

2327

DOE026-0050

Martin, Adrienne b5

From: Anderson, Margot
Sent: Tuesday, February 20, 2001 5:29 PM
To: Beschen, Darrell; 'Margot Andersen@DOE%HQ-NOTES'
Subject: RE: The Regional piece....reminder

Can't read. Please take most recent copy and hand write edits and deliver. by 5.45. Thanks.

-----Original Message-----
From: Darrell Beschen
Sent: Tuesday, February 20, 2001 4:26 PM
To: Anderson, Margot; Margot Andersen@DOE%HQ-NOTES
Subject: Re: The Regional piece....reminder

..only the magenta stuff counts.....d.

---------------------- Forwarded by Darrell Beschen/EE/DOE on 02/20/2001 04:24 PM ---------------------------

Jerry Dion
02/20/2001 04:06 PM

To: Darrell Beschen/EE/DOE@DOE
cc:

Subject: Re: The Regional piece....reminder

Darrell,

Jerry

DARRELL BESCHEN
02/20/2001 09:49 AM

To: #EE-DAS, #EE-ADAS, Kenneth Friedman/EE/DOE@DOE, Jerry Dion/EE/DOE@DOE, Linda Silverman/EE/DOE@DOE, Ellyn Krevitz/EE/DOE@DOE, Ed Wall/EE/DOE@DOE, David Rodgers/EE/DOE@DOE, Douglas Kaempf/EE/DOE@DOE
cc: Gail McKinley/EE/DOE@DOE, Phillip Tseng/EE/DOE@DOE, Peggy Podolak/EE/DOE@DOE, William Noel/EE/DOE@DOE, Philip Overholt/EE/DOE@DOE, Lawrence Mansueti/EE/DOE@DOE, Sam Baldwin/EE/DOE@DOE, Darrell Beschen/EE/DOE@DOE, Michael York/EE/DOE@DOE, Joel Rubin/EE/DOE@DOE, Nancy Jeffery/EE/DOE@DOE, Philip Patterson/EE/DOE@DOE

Subject: The Regional piece....reminder

2380

Current text on the regional piece:

b5

<< File: ATTACHMENT.TXT >> << File: The Short Term Energy Situation BTS region.doc >>

2382

Martin, Adrienne

b5

From: Anderson, Margot
Sent: Thursday, March 01, 2001 12:47 PM
To: 'Charles_M._Smith@ovp.eop.gov%internet'
Subject: RE: Feedback on captions

Sent: Thursday, March 01, 2001 12:38 PM
To: Anderson, Margot
Subject: Feedback on captions

Margot:

---------------------- Forwarded by Charles M. Smith/OVP/EOP on 03/01/2001 12:32 PM ---------------------------

(Embedded image moved to file: PIC05332.PCX)
CommColl@aol.com
03/01/2001 11:43:01 AM

Record Type: Record

To: Charles M. Smith/OVP/EOP

cc:
Subject: Feedback on captions

Charlie--

2398

DOE026-0120

2399

Martin, Adrienne

(?) – 5

From: Anderson, Margot
Sent: Monday, February 12, 2001 10:47 AM
To: Conti, John; Breed, William; Friedrichs, Mark; Paik, Inja; Bradley, Richard; Newton, Bill
Subject: FW: National Energy Strategy

As we discussed.

-----Original Message-----
From: Kelliher, Joseph
Sent: Friday, February 09, 2001 6:39 PM
To: Anderson, Margot
Subject: RE: National Energy Strategy

Thanks, I was just writing you. Here it is.

taskoutst1.doc

-----Original Message-----
From: Anderson, Margot
Sent: Friday, February 09, 2001 6:39 PM
To: Kelliher, Joseph
Subject: National Energy Strategy

Joe,

Please don't forget to send your outline before you take off this evening. I'll get it around to the group.

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Friday, February 09, 2001 4:35 PM
To: Anderson, Margot
Subject: RE: Summer Electricity Assessment meeting

I invited Abe Haspel and FE to our meeting, since they will have to be involved in our new project for the Vice President's task force. Abe will be there, but not FE.

-----Original Message-----
From: Anderson, Margot
Sent: Friday, February 09, 2001 12:43 PM
To: Carrier, Paul; 'JKStier@bpa.gov'; Conti, John; SCHNAPP, ROBERT; 'CAball@bpa.gov'; Scalingi, Paula; PETTIS, LARRY; GEIDL, JOHN
Cc: Kelliher, Joseph; Whatley, Michael
Subject: RE: Summer Electricity Assessment meeting

All,

Today's meeting will be in 7B-138. CI's conference room. We will circulate a draft prior to the meeting.

Margot

-----Original Message-----
From: Anderson, Margot
Sent: Friday, February 09, 2001 11:42 AM
To: Anderson, Margot; Carrier, Paul; 'JKStier@bpa.gov'; Conti, John; SCHNAPP, ROBERT; 'CAball@bpa.gov'; Scalingi, Paula; PETTIS, LARRY; GEIDL, JOHN
Cc: Kelliher, Joseph; Whatley, Michael
Subject: RE: Summer Electricity Assessment meeting

All,

Due to scheduling conflicts, our meeting will be held at 5:00 today instead of 3:30. Thanks. I confirm a room number.

2401

DOE026-0125

Margot

-----Original Message-----
From: Anderson, Margot
Sent: Friday, February 09, 2001 11:29 AM
To: Carrier, Paul; 'JKStier@bpa.gov'; Conti, John; SCHNAPP, ROBERT; 'CAball@bpa.gov'; Scalingi, Paula; PETTIS, LARRY; GEIDL, JOHN
Cc: Kelliher, Joseph; Whatley, Michael
Subject: Summer Electricity Assessment meeting

All,

At the request of Joe Kelliher, we will be meeting at 3:30 today to go over the status of the summer electricity assessment report. PO will have a draft ready based on your contributions. As you are the points of contact and major, contributors, it would be helpful to have you attend the meeting. I will confirm a meeting room later today.

Margot Anderson
Acting Director, Office of Policy
6,2589

2402

DOE026-0126

Martin, Adrienne

From: Anderson, Margot
Sent: Monday, February 12, 2001 1:11 PM
To: Braitsch, Jay

Now with the attachment!

increased production eia.wpd

Margot

2406
DOE026-0130

Martin, Adrienne

From: Anderson, Margot
Sent: Monday, February 12, 2001 1:08 PM
To: Braitsch, Jay
Subject: increased production outline

Jay,

EIA took a stab at the increased production outline. Anything you think you want to incorporate?

Margot

2407

Martin, Adrienne b5

From:	Charles_M._Smith@ovp.eop.gov%internet [Charles_M._Smith@ovp.eop.gov]
Sent:	Monday, April 30, 2001 10:25 PM
To:	Kelliher, Joseph; Anderson, Margot; Moss.Jacob@epamail.epa.gov%internet; William_bettenberg@ios.doi.gov%internet; Tom_fulton@ios.doi.gov%internet
Cc:	Kjersten_drager@ovp.eop.gov%internet; Andrew_D._Lundquist@ovp.eop.gov%internet; Karen_Y._Knutson@ovp.eop.gov%internet
Subject:	chapter 3

The following are the remaining open items in the Environment chapter:

I need this literally first thing in the am. Chapter 3 is to be laid out starting about noon.

Charlie

2410

DOE026-0134

Martin, Adrienne

b5

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 11:50 AM
To: Anderson, Margot
Cc: Kripowicz, Robert; Rudins, George; Braitsch, Jay
Subject: Chap 3 - Coal gasification intro

Margot -

Intro material for goal gasification:

[It is not clear where this goes, my latest draft has this type of discussion on page 5, not page 9 as indicated in the question below.]

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:49 AM
To: Cook, Trevor; Carter, Douglas
Cc: Magwood, William
Subject: Going to Press: chapter 3

Doug and Trevor,

Chapter 3, the environment chapter has a few outstanding questions remaining but only 2 pertain to DOE.

By 10:00 if possible. Thanks.

Margot

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Monday, April 30, 2001 10:25 PM
To: Kelliher, Joseph; Anderson, Margot;
Moss.Jacob@epamail.epa.gov%internet;
William_bettenberg@ios.doi.gov%internet; Tom_fulton@ios.doi.gov%internet
Cc: Kjersten_drager@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet
Subject: chapter 3

The following are the remaining open items in the Environment chapter:

DOE - page 9.

3411

DOE026-0135

I need this literally first thing in the am. Chapter 3 is to be laid out starting about noon.

Charlie

2412

From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 10:28 AM
To: 'Charles_M._Smith@ovp.eop.gov%internet'; Anderson, Margot; 'Moss.Jacob@epamail.epa.gov%internet'; 'William_bettenberg@ios.doi.gov%internet'; 'Tom_fulton@ios.doi.gov%internet'
Cc: 'Kjersten_drager@ovp.eop.gov%internet'; 'Andrew_D._Lundquist@ovp.eop.gov%internet'; 'Karen_Y._Knutson@ovp.eop.gov%internet'
Subject: RE: chapter 3

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Monday, April 30, 2001 10:25 PM
To: Kelliher, Joseph; Anderson, Margot;
Moss.Jacob@epamail.epa.gov%internet;
William_bettenberg@ios.doi.gov%internet; Tom_fulton@ios.doi.gov%internet
Cc: Kjersten_drager@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet
Subject: chapter 3

The following are the remaining open items in the Environment chapter:

I need this literally first thing in the am. Chapter 3 is to be laid out starting about noon.

Charlie

65

Martin, Adrienne

From:	Poche, Michelle [Michelle.Poche@ost.dot.gov]
Sent:	Wednesday, April 04, 2001 8:29 PM
To:	Anderson, Margot
Subject:	RE: coal

-----Original Message-----
From: Anderson, Margot [mailto:Margot.Anderson@hq.doe.gov]
Sent: Thursday, March 29, 2001 6:48 PM
To: 'michelle.poche@dot.gov'
Subject: more DOE edits + graphics
Importance: High

Michelle,

I will try to get the graphics printed out here and delivered to Charlie.

Margot

> -----Original Message-----
> From: Freitas, Christopher
> Sent: Thursday, March 29, 2001 4:12 PM
> To: Anderson, Margot
> Cc: Como, Anthony; DeHoratiis, Guido; Johnson, Nancy
> Subject: RE: NEP chapter 9 --Final edits
> Importance: High
>
>
>
>
>
>
> <<Permits Flow.jpg>> <<Pipeline Construction.jpg>> <<Permits
> Schedule.jpg>> <<Ch9.03.28.doc>>
> Margot, FYI see attached file and my (FE-30) corrections/edits.
>
>
>
> Sincerely,
>
> Christopher J. Freitas
> Program Manager, Natural Gas Infrastructure
> (202) 586-1657
>
> -----Original Message-----
> From: Anderson, Margot
> Sent: Thursday, March 29, 2001 8:53 AM
> To: Conti, John; Haspel, Abe; Zimmerman, MaryBeth; Lockwood, Andrea;
> Breed, William; KYDES, ANDY; Whatley, Michael; Carter, Douglas; Braitsch,

2444

DOE026-0138

> Jay; Melchert, Elena; Cook, Trevor; Breed, William; 'jkstier@bpa.gov';
> York, Michael; Freitas, Christopher; Friedrichs, Mark; Pumphrey, David;
> Kolevar, Kevin; Pumphrey, David; Scalingi, Paula
> Cc: Kelliher, Joseph
> Subject: chapter 9
>

> Crystal - still no luck getting through to Jeff but we much need a BPA
> review, Can you help?
>
> Thanks,
>
> Margot
> << File: Ch9.03.28.doc >> << File: Silicon Valley.doc >> << File:
> transmissionprobmap.doc >>

2515

Martin, Adrienne

b5

From: KYDES, ANDY
Sent: Monday, April 30, 2001 8:27 PM
To: Anderson, Margot
Cc: HUTZLER, MARY
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

Here is a minor correction

Andy

-----Original Message-----
From: Schnapp, Robert
Sent: Monday, April 30, 2001 4:15 PM
To: Kydes, Andy
Cc: Kanhouwa, Suraj; Geidl, John
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

Andy,

Here are Suraj's comments. If you have any further questions, please give him a
call at 7-1919.

Thanks,

Bob

-----Original Message-----
From: Kanhouwa, Suraj
Sent: Monday, April 30, 2001 4:10 PM
To: Schnapp, Robert
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...
Importance: High

Bob:

Some amendments to what I sent earlier:

Suraj

-----Original Message-----
From: Kanhouwa, Suraj
Sent: Monday, April 30, 2001 03:49 PM
To: Schnapp, Robert
Subject: RE: Info. Needed for Chapter 5 by 3:00 TODAY...
Importance: Low

Bob:

I have gone through the document very rapidly.

2416

b5

Suraj

-----Original Message-----
From: Schnapp, Robert
Sent: Monday, April 30, 2001 02:45 PM
To: Kanhouwa, Suraj
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...
Importance: High

Suraj,

Can you please look at this right away and let me know if there are any errors.
They need it by 3 today.

Thanks,

Bob

-----Original Message-----
From: Kydes, Andy
Sent: Monday, April 30, 2001 1:59 PM
To: Schnapp, Robert; Benneche, Joseph
Cc: Pettis, Larry; Hutzler, Mary
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

Bob:

Thanks for your help.

Andy

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Monday, April 30, 2001 11:15 AM
To: Kydes, Andy; Douglas Carter_at_HQ-EXCH at X400PO; William Breed_at_HQ-EXCH at X400PO
Cc: Joseph Kelliher_at_HQ-EXCH at X400PO
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

2417

Doug and Andy,

Bill, PO should be on call to help if asked.

Margot

-----Original Message-----
From: Kjersten_S._Drager@ovp.eop.gov%internet
[mailto:Kjersten_S._Drager@ovp.eop.gov]
Sent: Monday, April 30, 2001 10:56 AM
To: McSlarrow, Kyle; Anderson, Margot; Kelliher, Joseph
Cc: Karen_Y._Knutson@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Charles_M._Smith@ovp.eop.gov%internet
Subject: Info. Needed for Chapter 5 by 3:00 TODAY...

(See attached file: Chapter Five Assignments.doc)

Please e-mail me the pertinent information ASAP as I am keeping track of everything outstanding for Andrew and Karen.

Also attached is a copy of the Chapter Five draft that we've been working from so you can refer to that it if you don't already have a copy.

Thanks so much! -Kjersten

2418

Martin, Adrienne b5

From: KYDES, ANDY
Sent: Monday, April 30, 2001 8:32 PM
To: Anderson, Margot
Cc: HUTZLER, MARY
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

More data checking on 5.

Andy
-----Original Message-----
From: Benneche, Joseph
Sent: Monday, April 30, 2001 5:31 PM
To: Kydes, Andy
Subject: RE: Info. Needed for Chapter 5 by 3:00 TODAY...

Forecast comments on chapter 5:

2419
DOE026-0143

-----Original Message-----
From: Kydes, Andy
Sent: Monday, April 30, 2001 1:59 PM
To: Schnapp, Robert; Benneche, Joseph
Cc: Pettis, Larry; Hutzler, Mary
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

Bob:

Thanks for your help.

Andy

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Monday, April 30, 2001 11:15 AM
To: Kydes, Andy; Douglas Carter_at_HQ-EXCH at X400PO; William Breed_at_HQ-EXCH at X400PO
Cc: Joseph Kelliher_at_HQ-EXCH at X400PO
Subject: FW: Info. Needed for Chapter 5 by 3:00 TODAY...

Andy. What's reasonable goal for fact checking this chapter?

Bill, PO should be on call to help if asked.

Margot

-----Original Message-----
From: Kjersten_S._Drager@ovp.eop.gov%internet

2420

[mailto:Kjersten_S._Drager@ovp.eop.gov]
Sent: Monday, April 30, 2001 10:56 AM
To: McSlarrow, Kyle; Anderson, Margot; Kelliher, Joseph
Cc: Karen_Y._Knutson@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Charles_M._Smith@ovp.eop.gov%internet
Subject: Info. Needed for Chapter 5 by 3:00 TODAY...

(See attached file: Chapter Five Assignments.doc)

(See attached file: CHAPTER 5 - original.doc)

Also attached is a copy of the Chapter Five draft that we've been working from so you can refer to that it if you don't already have a copy.

Margot - we still need EIA to fact check Chapters 3, 5, 6, 7 and 8.

Thanks so much! -Kjersten << File: CHAPTERF.DOC >> << File: CHAPTER5.DOC >>

2421

Martin, Adrienne

From: Carter, Douglas
Sent: Monday, April 30, 2001 4:45 PM
To: Anderson, Margot
Subject: RE: Questions for Infrastructure chapter (Joe, FE, PO, EIA)

Chapter Five Assignments O&G.d...

Margot -

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 4:15 PM
To: Carter, Douglas
Cc: Braitsch, Jay; Kripowicz, Robert
Subject: RE: Questions for Infrastructure chapter (Joe, FE, PO, EIA)

Doug,

I only sent stuff to you.

Can you recap what I've got.

Margot

-----Original Message-----
From: Carter, Douglas
Sent: Monday, April 30, 2001 3:20 PM
To: Anderson, Margot
Cc: Braitsch, Jay; Kripowicz, Robert
Subject: RE: Questions for Infrastructure chapter (Joe, FE, PO, EIA)

Margot:

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 9:03 AM
To: Freitas, Christopher; Carter, Douglas; Breed, William; McNutt, Barry; Kelliher, Joseph; KYDES, ANDY
Subject: FW: Questions for Infrastructure chapter (Joe, FE, PO, EIA)

Martin, Adrienne

From: Carter, Douglas
Sent: Monday, April 30, 2001 3:20 PM
To: Anderson, Margot
Cc: Braitsch, Jay; Kripowicz, Robert
Subject: RE: Questions for Infrastructure chapter (Joe, FE, PO, EIA)

Infrastructure correction.doc

Margot:

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 9:03 AM
To: Freitas, Christopher; Carter, Douglas; Breed, William; McNutt, Barry; Kelliher, Joseph; KYDES, ANDY
Subject: FW: Questions for Infrastructure chapter (Joe, FE, PO, EIA)

Another NEP chapter:

Joe: WH wants several policy recommendations. Charlie indicated this was you assignment. Please call an let me know if you want help.

Please call if you have questions. 6-2569

Margot

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Monday, April 30, 2001 8:24 AM
To: Kelliher, Joseph; Anderson, Margot;
Michelle.Poche@OST.DOT.Gov%Internet;
William_bettenberg@ios.doi.gov%internet;
Tom_fulton@ios.doi.gov%internet; Kjersten_drager@ovp.eop.gov%internet
Cc: Kjersten_drager@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet
Subject: Questions for Infrastructure chapter

With respect to the Infrastructure section, the following questions need to be addressed and answers provided by 3:00 PM, Monday, April 30, 2001. If you have any questions, give me a call. I'm on 456-7874. I've also attached a copy of the draft chapter we've been working from.

2423

DOE026-0147

2424

Martin, Adrienne b5

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 11:23 AM
To: Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert; Anderson, Margot; Braitsch, Jay
Subject: RE: clean coal

Joe -

Doug

-----Original Message-----
From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 10:37 AM
To: Carter, Douglas; Anderson, Margot
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

-----Original Message-----
From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:35 AM
To: Anderson, Margot; Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

If this doesn't work, please email or call me at x69684.

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:28 AM
To: Carter, Douglas
Subject: FW: clean coal

Doug,

Can you fill this is for Joe Kelliher?

margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:49 PM

2426

DOE026-0150

To: Anderson, Margot
Subject: RE: clean coal

Yes. in addition. They want something like this (I guess):

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe,

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

2427

DOE026-0151

Martin, Adrienne

b5

From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 10:37 AM
To: Carter, Douglas; Anderson, Margot
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

-----Original Message-----
From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:35 AM
To: Anderson, Margot; Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

If this doesn't work, please email or call me at x69684.

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:28 AM
To: Carter, Douglas
Subject: FW: clean coal

Doug,

Can you fill this is for Joe Kelliher?

margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:49 PM
To: Anderson, Margot
Subject: RE: clean coal

Yes, in addition. They want something like this (I guess):

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe,

2428

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

2429

Martin, Adrienne

b5.

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:35 AM
To: Anderson, Margot; Kelliher, Joseph
Cc: Rudins, George; Kripowicz, Robert
Subject: RE: clean coal

If this doesn't work, please email or call me at x69684.

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, May 01, 2001 8:28 AM
To: Carter, Douglas
Subject: FW: clean coal

Doug,

Can you fill this is for Joe Kelliher?

margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:49 PM
To: Anderson, Margot
Subject: RE: clean coal

Yes, in addition. They want something like this (I guess):

From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe,

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot

2430

DOE026-0154

Subject: clean coal

2431

DOE026-0155

Martin, Adrienne

b5

From:	Kelliher, Joseph
Sent:	Monday, April 30, 2001 6:49 PM
To:	Anderson, Margot
Subject:	RE: clean coal

Yes, in addition. They want something like this (I guess):

From:	Anderson, Margot
Sent:	Monday, April 30, 2001 6:19 PM
To:	Kelliher, Joseph; Kripowicz, Robert
Cc:	Carter, Douglas; DeHoratiis, Guido
Subject:	RE: clean coal

Joe,

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

2432

DOE026-0156

Martin, Adrienne b5

From:	Kelliher, Joseph
Sent:	Monday, April 30, 2001 6:16 PM
To:	Kripowicz, Robert
Cc:	Anderson, Margot
Subject:	clean coal

2423
DOE026-0157

Martin, Adrienne

b5

From: Carter, Douglas
Sent: Tuesday, May 01, 2001 10:26 AM
To: Anderson, Margot; Kelliher, Joseph; Kripowicz, Robert
Cc: Rudins, George
Subject: RE: clean coal

Attached is descriptive info on the CCTP.

Doug

Clean Coal Technology Program...

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 30, 2001 6:19 PM
To: Kelliher, Joseph; Kripowicz, Robert
Cc: Carter, Douglas; DeHoratiis, Guido
Subject: RE: clean coal

Joe,

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, April 30, 2001 6:16 PM
To: Kripowicz, Robert
Cc: Anderson, Margot
Subject: clean coal

2434

DOE026-0158

65

Martin, Adrienne

From:	KYDES, ANDY
Sent:	Wednesday, April 25, 2001 8:05 PM
To:	Anderson, Margot
Cc:	HUTZLER, MARY; PETTIS, LARRY; HOLTE, SUSAN; SITZER, SCOTT; KENDELL, JAMES; COSTELLO, DAVE; KYDES, ANDY
Subject:	RE: NEP help on Chapter 1

JK_042-1.PPT ELECTR~1.PPT CHAPTE~2.DOC

Margot

Here is the material you asked for.

Some first pass issues/suggestions:

-----Original Message-----
From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Wednesday, April 25, 2001 8:42 AM
To: Kydes, Andy
Subject: RE: NEP help on Chapter 1

thanks.

-----Original Message-----
From: KYDES, ANDY
Sent: Wednesday, April 25, 2001 11:23 AM
To: Anderson, Margot
Subject: RE: NEP help on Chapter 1

Yes

-----Original Message-----

2436

DOE026-0160

From: Margot Anderson_at_HQ-EXCH at X400PO
Sent: Tuesday, April 24, 2001 6:08 PM
To: Kydes, Andy; Pettis, Larry; Jay Braitsch_at_HQ-EXCH at X400PO; Douglas Carter_at_HQ-EXCH at X400PO; William Breed_at_HQ-EXCH at X400PO; John Conti_at_HQ-EXCH at X400PO; MaryBeth Zimmerman_at_HQ-NOTES at X400PO; Darrell Beschen_at_HQ-NOTES at X400PO
Cc: Joseph Kelliher_at_HQ-EXCH at X400PO
Subject: NEP help on Chapter 1

Folks,

. Can we meet a 11:00 in the morning? We can get through the list in an nour. Please let me know if you can attend. 7B-040

Margot

2437

Martin, Adrienne

From:	Charles_M._Smith@ovp.eop.gov%internet [Charles_M._Smith@ovp.eop.gov]
Sent:	Thursday, March 08, 2001 11:57 AM
To:	Kelliher, Joseph; Anderson, Margot; Dina.Ellis@do.treas.gov%internet; Galloglysj@State.gov%internet; McManusmj@State.gov%internet; Michelle.Poche@OST.DOT.Gov%internet; Brenner.Rob@EPA.gov%internet; Symons.Jeremy@EPA.gov%internet
Cc:	commcoll@aol.com%internet; Andrew_D._Lundquist@ovp.eop.gov%internet; Karen_Y._Knutson%EOPJohn_Fenzel%OVP.EOP.GOV@oa.eop.gov%internet; Kjersten_S._Drager@ovp.eop.gov%internet

With respect to photos, DOE has a Digital Archive that you can access at:

http://www.doedigitalarchive.doe.gov

The DOE Publications group also has a librarian on staff who can help find pictures that illustrate the point you may be trying to make. Apparently, the photo library is huge with 10s of thousands of images. Let me know if you need her help and I'll set it up.

Attachment 1

2443

DOE026-0167

2444

Martin, Adrienne

From:	Brown.Ellen@epamail.epa.gov%internet [Brown.Ellen@epamail.epa.gov]
Sent:	Friday; March 09, 2001 12:38 PM
To:	Anderson, Margot
Cc:	Symons.Jeremy@epamail.epa.gov%internet; Laitner.Skip@epamail.epa.gov%internet; Hall.Johnm@epamail.epa.gov%internet; Schultheisz.Daniel@epamail.epa.gov%internet
Subject:	chapter 8 comments

b5

tmp.htm

Margot,

We scrambled to put this together this morning. I hope these comments won't be too difficult to use. I never got an electronic copy of chapter 8 so I am not able to give you a redline strikeout.

b5

b5

b5

b5

b5

b5

b5

2445

DOE026-0169

2446

Martin, Adrienne

b5

From: Kelliher, Joseph
Sent: Friday, March 30, 2001 10:34 AM
To: Anderson, Margot; Kripowicz, Robert
Subject: coal transportation

2449

Martin, Adrienne b5

From: Kelliher, Joseph
Sent: Friday, March 23, 2001 8:39 AM
To: Anderson, Margot
Subject: policy options

Importance: High

neplist1.doc

2450

Martin, Adrienne

b5

From: Vernet, Jean
Sent: Tuesday, May 01, 2001 3:12 PM
To: Kelliher, Joseph; Anderson, Margot
Cc: Conti, John; Carter, Douglas
Subject: RE: NSR

Importance: High

Joe,

Just got to look at this. I was out of the office yesterday and this morning at a conference. Please let me know your reaction, and where this stands.

Jean

-----Original Message-----
From: Kelliher, Joseph
Sent: Sunday, April 29, 2001 5:05 PM
To: Vernet, Jean; Anderson, Margot
Subject: NSR

2458

Sorry for the delay.

Thanks. (b)(5)

-----Original Message-----
From: Schmidt.Lorie@epamail.epa.gov%internet
[mailto:Schmidt.Lorie@epamail.epa.gov]
Sent: Tuesday, April 24, 2001 12:08 PM
To: Kelliher, Joseph
Cc: Stevenson, Beverley
Subject: NEPD Recommendations

Joe

I didn't catch Jean's last name, so could you please forward this to her?

Thanks,

Lorie Schmidt
564-1681

(See attached file: nsr rec 4-24.wpd)

2459

Martin, Adrienne

b5

From: Kelliher, Joseph
Sent: Tuesday, May 01, 2001 7:50 AM
To: 'Charles_M._Smith@ovp.eop.gov%internet'; Anderson, Margot; 'William_bettenberg@ios.doi.gov%internet'; 'Tom_fulton@ios.doi.gov%internet'
Cc: 'Kjersten_drager@ovp.eop.gov%internet'; 'Andrew_D._Lundquist@ovp.eop.gov%internet'; 'Karen_Y._Knutson@ovp.eop.gov%internet'
Subject: RE: Chapter 7 requirements

I sent you a path 15 insert yesterday morning. Here it is again:

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Monday, April 30, 2001 10:29 PM
To: Kelliher, Joseph; Anderson, Margot;
William_bettenberg@ios.doi.gov%internet; Tom_fulton@ios.doi.gov%internet
Cc: Kjersten_drager@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet
Subject: Chapter 7 requirements

With respect to Chapter 7, we still need the following:

Let's clean this up so we can get this thing closed.

Charlie

2460

DOE026-0184

Martin, Adrienne b5

From:	Freitas, Christopher
Sent:	Monday, April 23, 2001 12:43 PM
To:	Anderson, Margot
Cc:	DeHoratiis, Guido; Braitsch, Jay; Johnson, Nancy
Subject:	FW: Edited chapter 9
Importance:	High

ch.DOC PIC31207.PCX

Thanks

Sincerely,

Christopher J. Freitas
Program Manager, Natural Gas Infrastructure
(202) 586-1657

-----Original Message-----
From: Braitsch, Jay
Sent: Friday, April 20, 2001 5:00 PM
To: Kripowicz, Robert; DeHoratiis, Guido; Johnson, Nancy; Freitas, Christopher; Rudins, George; Carter, Douglas
Cc: Bajura, Rita
Subject: FW: Edited chapter 9

FYI

-----Original Message-----
From: Anderson, Margot
Sent: Friday, April 20, 2001 4:54 PM
To: Braitsch, Jay; Breed, William; Kelliher, Joseph
Subject: FW: Edited chapter 9

All,
All,

Margot
-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Friday, April 20, 2001 4:44 PM
To: Anderson, Margot
Subject: Edited chapter 9

---------------------- Forwarded by Charles M. Smith/OVP/EOP on 04/20/2001
04:44 PM ---------------------------

2461

(Embedded
image moved CommColl@aol.com
to file: 04/19/2001 11:58:19 AM
PIC31207.PCX)

Record Type: Record

To: Charles M. Smith/OVP/EOP

cc:
Subject: Edited chapter 9

Charlie--
Attached is the edited chapter 9. Please note a few things:

(b)(5)

2462

DOE026-0186

65

Martin, Adrienne

From:	Charles_M._Smith@ovp.eop.gov%internet [Charles_M._Smith@ovp.eop.gov]
Sent:	Friday, April 20, 2001 4:44 PM
To:	Anderson, Margot
Subject:	Re: Environment Chapter

env't ch 4-18 8 pm.DOC   env't ch 4-18.DOC   ATTACHMENT.TXT   PIC20353.PCX

fyi

---------------------- Forwarded by Charles M. Smith/OVP/EOP on 04/20/2001 04:43 PM ---------------------------

(Embedded
image moved   Schmidt.Lorie@epamail.epa.gov
to file: 04/18/2001 08:16:13 PM
PIC20353.PCX)

Record Type: Record

To: Schmidt.Lorie@epamail.epa.gov

cc: See the distribution list at the bottom of this message
Subject: Re: Environment Chapter

Charlie

(See attached file: env't ch 4-18 8 pm.DOC)
Lorie

Lorie Schmidt
To:
Charles_M._Smith@ovp.eop.gov
04/18/2001   cc:
William_Bettenberg@ios.doi.gov,
02:10 PM   Kmurphy@osec.doc.gov, Tom
Gibson/DC/USEPA/US@EPA, Jacob
Moss/DC/USEPA/US@EPA
Subject: Environment
Chapter(Document
link: Lorie Schmidt)

Charlie
Here's the environment chapter as reworked by Bill. Kevin and me.

Also -- I'll have some photos sent over to you today.

2481

DOE026-0205

Lorie
564-1681
(See attached file: env'l ch 4-18.DOC)

2482

Message Copied
To:

Charles M. Smith/OVP/EOP
Moss.Jacob@epamail.epa.gov
Kmurphy@osec.doc.gov
Gibson.Tom@epamail.epa.gov
William_Bettenberg@ios.doi.gov

2517

Martin, Adrienne b5

From:	Breed, William
Sent:	Tuesday, March 27, 2001 8:55 AM
To:	Anderson, Margot
Subject:	Q's from Joe K

Margot:

attached is a 3-pager on Coal in Federal lands, pulled from a USGS report (July '99) -

Acting Director, Office of Energy Efficiency,
Alternative Fuels, and Oil Analysis (PO-22)
202-586-4763

Coal Resources on Federal Land...

2518

Martin, Adrienne

65

From:	Kelliher, Joseph
Sent:	Monday, March 26, 2001 10:48 AM
To:	Anderson, Margot
Subject:	questions
Importance:	High

A few questions to help winnow down our list even more --

2522

DOE026-0246

Martin, Adrienne 65

From:	Brown.Ellen@epamail.epa.gov%internet [Brown.Ellen@epamail.epa.gov]
Sent:	Friday, March 09, 2001 1:23 PM
To:	Anderson, Margot
Subject:	more on 8

tmp.htm

Margot, I just got these but they seem helpful so I am passing them on.

Ellen

2523

DOE026-0247

Martin, Adrienne b5

From: Anderson, Margot
Sent: Tuesday, May 01, 2001 9:55 AM
To: 'Charles Smith (E-mail)'
Cc: Freitas, Christopher
Subject:

Charlie,

chapter 9 DOE comments april 2...

2525

DOE026-0249

b5

Martin, Adrienne

From:	Anderson, Margot
Sent:	Tuesday, May 08, 2001 11:21 AM
To:	Braitsch, Jay; Freitas, Christopher; Conti, John; Breed, William; KYDES, ANDY
Subject:	DOT request for chapter
Importance:	High
Sensitivity:	Confidential

Lotus Manuscript 1.0 ch7.DOC

Jay and John,

Let each of us know (by responding to all) which questions you can do, so we don't duplicate effort.

Margot

-----Original Message-----
From: Poche, Michelle [mailto:Michelle.Poche@ost.dot.gov]
Sent: Tuesday, May 08, 2001 10:55 AM
To: Anderson, Margot; Lawson, Linda; Joost, Elaine (060)RSPA(062); Brigham, Edward (060)RSPA(062); O'Leary, Jeanne; Kelliher, Joseph; 'Moss.Jacob(a)epamail.epa.gov'; 'Kmurphy(a)osec.doc.gov'; Ebersold, Bill (060)MARAD(062); Brown, Manson CAPT(060)USCG(062); 'Tom(u)Fulton(a)OS.DOI.gov'; 'Sue(u)Ellen(u)Wooldridge(a)IOS.DOI.gov'
Cc: 'Elena(u)S.(u)Melchert(a)ovp.eop.gov'
Subject: URGENT: National Energy Policy: citations request
Importance: High
Sensitivity: Confidential

URGENT - DEADLINE 3:00 PM TODAY

Thanks,
Michelle

Michelle Poché
Office of Secretary Norman Y. Mineta

2543

U.S. Department of Transportation
202-366-0251

-----Original Message-----
From: Elena_S._Melchert@ovp.eop.gov
[mailto:Elena_S._Melchert@ovp.eop.gov]
Sent: Monday, May 07, 2001 2:27 PM
To: Poche, Michelle
Subject: National Energy Policy: citations request

(See attached file: CitationsCHAPTER 7.doc)

Please call me if you have any questions.
Thanks fo ryour help on this.
Elena
202/456-5348

2544

DOE026-0269

Martin, Adrienne b5

From: Anderson, Margot
Sent: Tuesday, May 08, 2001 11:12 AM
To: 'Poche, Michelle'
Cc: 'Elena(u)S.(u)Melchert(a)ovp.eop.gov'
Subject: RE: URGENT: National Energy Policy: citations request

Sensitivity: Confidential

Citations Chapter 7.doc

Michelle,

Margot

-----Original Message-----
From: Poche, Michelle [mailto:Michelle.Poche@ost.dot.gov]
Sent: Tuesday, May 08, 2001 10:55 AM
To: Anderson, Margot; Lawson, Linda; Joost, Elaine (060)RSPA(062); Brigham, Edward (060)RSPA(062); O'Leary, Jeanne; Kelliher, Joseph; 'Moss.Jacob(a)epamail.epa.gov'; 'Kmurphy(a)osec.doc.gov'; Ebersold, Bill (060)MARAD(062); Brown, Manson CAPT(060)USCG(062); 'Tom(u)Fulton(a)OS.DOI.gov'; 'Sue(u)Ellen(u)Wooldridge(a)IOS.DOI.gov'
Cc: 'Elena(u)S.(u)Melchert(a)ovp.eop.gov'
Subject: URGENT: National Energy Policy: citations request
Importance: High
Sensitivity: Confidential

URGENT - DEADLINE 3:00 PM TODAY

Thanks,
Michelle

Michelle Poché
Office of Secretary Norman Y. Mineta
U.S. Department of Transportation
202-366-0251

2570

DOE026-0295

-----Original Message-----
From: Elena_S._Melchert@ovp.eop.gov
[mailto:Elena_S._Melchert@ovp.eop.gov]
Sent: Monday, May 07, 2001 2:27 PM
To: Poche, Michelle
Subject: National Energy Policy: citations request

(See attached file: CitationsCHAPTER 7.doc)

Please call me if you have any questions.
Thanks fo ryour help on this.
Elena
202/456-5348

2571

Martin, Adrienne

From: Anderson, Margot
Sent: Monday, May 07, 2001 6:27 PM
To: 'Elena Melchert (E-mail)'
Subject: FW: NEP - Chapter 7

CITATI~9.DOC

Elena,

More on 7.

Margot

-----Original Message-----
From: HOLTE, SUSAN
Sent: Monday, May 07, 2001 9:08 PM
To: Anderson, Margot
Cc: HUTZLER, MARY; KYDES, ANDY
Subject: NEP - Chapter 7

Susan H. Holte
202/586-4838

2579

Martin, Adrienne

From: Anderson, Margot
Sent: Wednesday, April 18, 2001 9:56 AM
To: Braitsch, Jay
Subject: FW: Edited chapter 8

ch.DOC PIC20285.PCX

As we are discussing.

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Wednesday, April 18, 2001 9:41 AM
To: Anderson, Margot
Subject: Edited chapter 8

Margot:

FYI
---------------------- Forwarded by Charles M. Smith/OVP/EOP on 04/18/2001
09:40 AM ---------------------------

(Embedded
image moved CommColl@aol.com
to file: 04/18/2001 09:24:05 AM
PIC20285.PCX)

Record Type: Record

To: Charles M. Smith/OVP/EOP

cc:
Subject: Edited chapter 8

Charlie--

5

b5

2587

5

b5

What does this mean?
I think that does it for this chapter.
Joan

2588

Martin, Adrienne

From: Kripowicz, Robert
Sent: Tuesday, April 03, 2001 5:33 PM
To: Kolevar, Kevin
Cc: Anderson, Margot; Kelliher, Joseph; Braitsch, Jay
Subject: FW: Integrating GHG Reduction into the NEP

Importance: High

Kevin – Based on previous e-mails I offer the following:

b5

Voluntary Reduction of Greenho...

NewCoalPower FE 3.8.01.doc

Sequest FE #2.doc

b5

ClimateChangePlan.doc

2601

Martin, Adrienne

From: Anderson, Margot
Sent: Tuesday, April 03, 2001 5:47 PM
To: Kripowicz, Robert; Kolevar, Kevin
Cc: Kelliher, Joseph; Braitsch, Jay
Subject: RE: Integrating GHG Reduction into the NEP

Bob,

Thanks for cc'ing me on this.

Will circulate

Margot

-----Original Message-----
From: Kripowicz, Robert
Sent: Tuesday, April 03, 2001 5:33 PM
To: Kolevar, Kevin
Cc: Anderson, Margot; Kelliher, Joseph; Braitsch, Jay
Subject: FW: Integrating GHG Reduction into the NEP
Importance: High

Kevin -- Based on previous e-mails I offer the following:

<< File: ClimateChangePlan.doc >>

2608

DOE026-0333

Martin, Adrienne

From:	Anderson, Margot
Sent:	Wednesday, February 14, 2001 3:40 PM
To:	Magwood, William
Subject:	RE: draft NEP instructions

Naw, wait. Thanks

-----Original Message-----
From: Magwood, William
Sent: Wednesday, February 14, 2001 3:23 PM
To: Anderson, Margot
Subject: RE: draft NEP instructions

Margot,

Do you need a paragraph now? I'd rather provide suggested text on Friday in "final" form. Let me know if you need something today.

WDM

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 14, 2001 2:10 PM
To: Magwood, William
Subject: RE: draft NEP instructions

Bill,

Thanks.

b5

-----Original Message-----
From: Magwood, William
Sent: Wednesday, February 14, 2001 1:49 PM
To: Anderson, Margot
Subject: RE: draft NEP instructions
Importance: High

Margot,

thanks,
WDM

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 14, 2001 12:38 PM
To: Kripowicz, Robert; Haspel, Abe; Sullivan, John; Zimmerman, MaryBeth; Magwood, William; Pumphrey, David; Hart, Carole; Scalingi, Paula; Whatley, Michael
Cc: Kelliher, Joseph
Subject: draft NEP instructions

All,

Please review.

What did I miss from the discussion today?

Martin, Adrienne

From: Anderson, Margot
Sent: Wednesday, February 14, 2001 2:10 PM
To: Magwood, William
Subject: RE: draft NEP instructions

Bill,

Thanks. Okay on section 5 - will add. Not clear how we will be engaging on section 7 (State has the lead) but
Do you have a paragraph you'd like to see included?

b5

Margot

-----Original Message-----
From: Magwood, William
Sent: Wednesday, February 14, 2001 1:49 PM
To: Anderson, Margot
Subject: RE: draft NEP instructions
Importance: High

Margot,

Thanks,
WDM

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 14, 2001 12:38 PM
To: Kripowicz, Robert; Haspel, Abe; Sullivan, John; Zimmerman, MaryBeth; Magwood, William; Pumphrey, David; Hart, Carole; Scalingi, Paula; Whatley, Michael
Cc: Kelliher, Joseph
Subject: draft NEP instructions

All,

Please review.

What did I miss from the discussion today?

Note assignments are by office - some of you are asked provide names to Joe, me or other offices to complete tasks.

If only one or two offices are contribtuing the bulk of the information, I am asking one office to compile the bits prior to sending to me. Saves me some time and I can focus on overall gaps.

Also attached outline Joe was working from.

Please get back to me by 2:30 (if possible) with your comments on the instructions. I will edit and send out "officially" ASAP.

I will also need to know who will be doing one so I dont' have to bug you all the time.

Margot

<< File: Draft combo outline WH.doc >> << File: NEP organization.doc >>

2610

Note assignments are by office - some of you are asked provide names to Joe, me or other offices to complete tasks.

If only one or two offices are contribtuing the bulk of the information, I am asking one office to compile the bits prior to sending to me. Saves me some time and I can focus on overall gaps.

Also attached outline Joe was working from.

Please get back to me by 2:30 (if possible) with your comments on the instructions. I will edit and send out "officially" ASAP.

I will also need to know who will be doing one so I dont' have to bug you all the time.

Margot

<< File: Draft combo outline WH.doc >> << File: NEP organization.doc >>

2611

Martin, Adrienne

From: Anderson, Margot
Sent: Wednesday, February 14, 2001 2:38 PM
To: Magwood, William
Subject: Clarification: you NEP instructions

Bill,

Help.

Please advise.

-----Original Message-----
From: Magwood, William
Sent: Wednesday, February 14, 2001 1:49 PM
To: Anderson, Margot
Subject: RE: draft NEP instructions
Importance: High

Margot,

b5

Thanks,
WDM

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 14, 2001 12:38 PM
To: Kripowicz, Robert; Haspel, Abe; Sullivan, John; Zimmerman, MaryBeth; Magwood, William; Pumphrey, David; Hart, Carole; Scalingi, Paula; Whatley, Michael
Cc: Kelliher, Joseph
Subject: draft NEP instructions

All,

Please review.

What did I miss from the discussion today?

Note assignments are by office - some of you are asked provide names to Joe, me or other offices to complete tasks.

If only one or two offices are contribtuing the bulk of the information, I am asking one office to compile the bits prior to sending to me. Saves me some time and I can focus on overall gaps.

Also attached outline Joe was working from.

Please get back to me by 2:30 (if possible) with your comments on the instructions. I will edit and send out "officially" ASAP.

I will also need to know who will be doing one so I dont' have to bug you all the time.

Margot

2612

, << File: Draft combo outline WH.doc >> << File: NEP organization.doc >>

2613

Martin, Adrienne

From: Anderson, Margot
Sent: Wednesday, February 14, 2001 3:37 PM
To: Magwood, William
Subject: RE: Clarification: you NEP instructions

okay, next draft out very soon.

-----Original Message-----
From: Magwood, William
Sent: Wednesday, February 14, 2001 3:21 PM
To: Anderson, Margot
Subject: RE: Clarification: you NEP instructions

Margot,

I didn't have a copy of the outline, so I may have missed that step. Let's try it using your understanding and we can adjust later if it doesn't work.

WDM

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 14, 2001 2:38 PM
To: Magwood, William
Subject: Clarification: you NEP instructions

Bill,

Help.

will

b5

Please advise.

-----Original Message-----
From: Magwood, William
Sent: Wednesday, February 14, 2001 1:49 PM
To: Anderson, Margot
Subject: RE: draft NEP instructions
Importance: High

Margot

Thanks,
WDM

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 14, 2001 12:38 PM
To: Kripowicz, Robert; Haspel, Abe; Sullivan, John; Zimmerman, MaryBeth; Magwood, William; Pumphrey, David; Hart, Carole; Scalingi, Paula; Whatley, Michael
Cc: Kelliher, Joseph
Subject: draft NEP instructions

2614

All,

Please review.

What did I miss from the discussion today?

Note assignments are by office - some of you are asked provide names to Joe, me or other offices to complete tasks.

If only one or two offices are contribtuing the bulk of the information, I am asking one office to compile the bits prior to sending to me. Saves me some time and I can focus on overall gaps.

Also attached outline Joe was working from.

Please get back to me by 2:30 (if possible) with your comments on the instructions. I will edit and send out "officially" ASAP.

I will also need to know who will be doing one so I dont' have to bug you all the time.

Margot

<< File: Draft combo outline WH.doc >> << File: NEP organization.doc >>

Martin, Adrienne

From: Anderson, Margot
Sent: Friday, March 23, 2001 2:08 PM
To: Carter, Douglas; Melchert, Elena
Cc: DeHoratiis, Guido
Subject: RE:

Thanks.

-----Original Message-----
From: Carter, Douglas
Sent: Friday, March 23, 2001 1:56 PM
To: Anderson, Margot; Melchert, Elena
Cc: DeHoratiis, Guido
Subject: RE:

Margot -

Elena will provide additional material for the O&G program.

Doug

<< File: Ch8 Elec Figs.ppt >>

-----Original Message-----
From: Anderson, Margot
Sent: Friday, March 23, 2001 1:12 PM
To: Melchert, Elena
Cc: DeHoratiis, Guido; Carter, Douglas
Subject: RE:

Thanks. I hate to ask, but do you have some nifty graphics?

-----Original Message-----
From: Melchert, Elena
Sent: Friday, March 23, 2001 1:08 PM
To: Anderson, Margot
Cc: DeHoratiis, Guido; Carter, Douglas
Subject:

Fossil Energy final Chapter 8
Thanks for your patience.
e << File: ch 8 march 23.doc >>

Elena Subia Melchert
Petroleum Engineer/Program Manager
Office of Fossil Energy
U.S. Department of Energy

2616

DOE026-0341

Martin, Adrienne

From: Carter, Douglas
Sent: Friday, March 23, 2001 3:24 PM
To: Anderson, Margot
Subject: RE:

Margot -

(b)(5)

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Friday, March 23, 2001 2:08 PM
To: Carter, Douglas; Melchert, Elena
Cc: DeHoratiis, Guido
Subject: RE:

Thanks.

(b)(5)

-----Original Message-----
From: Carter, Douglas
Sent: Friday, March 23, 2001 1:56 PM
To: Anderson, Margot; Melchert, Elena
Cc: DeHoratiis, Guido
Subject: RE:

Margot -

Elena will provide additional material for the O&G program.

Doug

<< File: Ch8 Elec Figs.ppt >>

-----Original Message-----
From: Anderson, Margot
Sent: Friday, March 23, 2001 1:12 PM
To: Melchert, Elena
Cc: DeHoratiis, Guido; Carter, Douglas
Subject: RE:

Thanks. I hate to ask, but do you have some nifty graphics?

-----Original Message-----
From: Melchert, Elena
Sent: Friday, March 23, 2001 1:08 PM

2617

To: Anderson, Margot
Cc: DeHoratiis, Guido; Carter, Douglas
Subject:

Fossil Energy final Chapter 8
Thanks for your patience.
e << File: ch 8 march 23.doc >>

Elena Subia Melchert
Petroleum Engineer/Program Manager
Office of Fossil Energy
U.S. Department of Energy

2618

DOE026-0343

Martin, Adrienne

From: Anderson, Margot
Sent: Monday, February 12, 2001 2:17 PM
To: Braitsch, Jay
Subject: FW: Impediments to Conventional Energy Production

Jay,

Margot

-----Original Message-----
From: Breed, William
Sent: Monday, February 12, 2001 2:17 PM
To: Anderson, Margot
Subject: RE: Impediments to Conventional Energy Production

Our comments:

2619

Another NEP chapter:

Please call if you have questions. 6-2589

Margot

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Monday, April 30, 2001 8:24 AM
To: Kelliher, Joseph; Anderson, Margot;
Michelle.Poche@OST.DOT.Gov%internet;
William_bettenberg@ios.doi.gov%internet;
Tom_fulton@ios.doi.gov%internet; Kjersten_drager@ovp.eop.gov%internet
Cc: Kjersten_drager@ovp.eop.gov%internet;
Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet
Subject: Questions for Infrastructure chapter

2620

Martin, Adrienne

From:	Kelliher, Joseph
Sent:	Friday, March 30, 2001 7:31 PM
To:	'Karen_Y._Knutson@OVP.EOP.Gov'; 'Andrew_D._Lundquist@OVP.EOP.Gov'; 'Charles_M._Smith@ovp.eop.gov%internet'; Anderson, Margot
Cc:	'Symons.Jeremy@epamail.epa.gov'
Subject:	nuclear energy paper

Sorry for the delay, it must be Noon somewhere in the world.

nuclear1.doc

2621

Martin, Adrienne

From:	Anderson, Margot
Sent:	Monday, May 07, 2001 3:29 PM
To:	Braitsch, Jay; Carter, Douglas
Subject:	FW: an additional fact not checked on friday

This just in from Trevor. Belongs in chapter 5. Can you add? Number 73.

-----Original Message-----

From:	Cook, Trevor
Sent:	Monday, May 07, 2001 3:26 PM
To:	Anderson, Margot
Subject:	an additional fact not checked on friday

its in bright pink... the only pink text in the file. No. 73.

Citation Check - ME - CH 5.doc...

2624

DOE026-0349

 b5

From: Kelliher, Joseph
Sent: Monday, April 02, 2001 12:19 PM
To: Anderson, Margot
Subject: RE: energy efficiency one-pager

-----Original Message-----
From: Anderson, Margot
Sent: Monday, April 02, 2001 10:51 AM
To: Kelliher, Joseph; 'Symons.Jeremy@epamail.epa.gov'
Cc: Kolevar, Kevin
Subject: RE: energy efficiency one-pager

Joe,

How do you want to proceed on this? Have you drafted a revised?

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Friday, March 30, 2001 6:48 PM
To: Anderson, Margot; 'Symons.Jeremy@epamail.epa.gov'
Cc: Kolevar, Kevin
Subject: RE: energy efficiency one-pager

-----Original Message-----
From: Anderson, Margot
Sent: Friday, March 30, 2001 5:40 PM
To: 'Symons.Jeremy@epamail.epa.gov'
Cc: Kelliher, Joseph; Kolevar, Kevin
Subject: energy efficiency one-pager

<< File: energy efficiency one-pager.wpd >>

Reviewed/edited by EE, PO. Joe and/or Kevin, Problems?

Jeremy, can you let me know if you get this? I am having problems with your e-mail.

Margot

2631

Martin, Adrienne

From:	Kelliher, Joseph
Sent:	Friday, March 30, 2001 6:48 PM
To:	Anderson, Margot; 'Symons.Jeremy@epamail.epa.gov'
Cc:	Kolevar, Kevin
Subject:	RE: energy efficiency one-pager

-----Original Message-----

From:	Anderson, Margot
Sent:	Friday, March 30, 2001 5:40 PM
To:	'Symons.Jeremy@epamail.epa.gov'
Cc:	Kelliher, Joseph; Kolevar, Kevin
Subject:	energy efficiency one-pager

<< File: energy efficiency one-pager.wpd >>

Reviewed/edited by EE, PO. Joe and/or Kevin, Problems?

Jeremy, can you let me know if you get this? I am having problems with your e-mail.

Margot

2632

DOE026-0357

Martin, Adrienne

From:	Carter, Douglas
Sent:	Tuesday, March 27, 2001 11:30 AM
To:	Anderson, Margot
Cc:	Braitsch, Jay; Kripowicz, Robert; Rudins, George; DeHoratiis, Guido; Melchert, Elena
Subject:	Chapter 8, changes

Margot -

ch 8 march 27.doc

Doug Carter (FE-26)
US DOE
Washington, DC 20585
202-586-9684

2633

Martin, Adrienne

From:	Breed, William
Sent:	Monday, March 26, 2001 1:29 PM
To:	Anderson, Margot
Subject:	quick comments on list of policies

b5

2643

DOE026-0368

SR/OOG/2001-01

Impact of Interruptible Natural Gas Service on Northeast Heating Oil Demand

January 2001

Energy Information Administration
Office of Oil and Gas
U.S. Department of Energy
Washington, DC 20585

2644

Preface

Impact of Interruptible Natural Gas Service on Northeast Heating Oil Demand was undertaken at the request of U.S. Secretary of Energy Bill Richardson to assess the extent of interruptible natural gas contracts and their effect on heating oil demand in the Northeast. An earlier report with policy recommendations was issued by the Department of Energy's Office of Policy in November 2000 that examined the effect of interruptible contracts in New England. The current report expands the geographic scope of the analysis by including New Jersey, New York, and Pennsylvania and presents a more comprehensive assessment of gas service interruptions, the responses of different types of customers, and the effects on the distillate fuel oil market.

The report is based on the results of two surveys developed by the Energy Information Administration (EIA): Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000," and Form EIA-904, "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000." The respondents to Form EIA-903 were 34 natural gas companies who provided 94 percent of natural gas deliveries to interruptible gas customers in the Northeast in 1998, while respondents to Form EIA-904 were 97 end users in New England who were identified by their suppliers as experiencing natural gas interruptions in the winter of 1999-2000.

The report has five chapters and four appendices. Chapter 1 gives an overview of the Northeast heating oil and natural gas markets during the winter of 1999-2000. Chapter 2 provides background information on natural gas markets in the Northeast and the role of interruptible contracts in the region's energy market. Chapter 3 examines the main factors that affect heating oil and natural gas prices by comparing market events during other periods of sharp price increases in recent years. Chapter 4 provides an analysis of the information derived from the EIA surveys of gas suppliers and customers, and Chapter 5 summarizes the market implications.

The report was prepared by the Energy Information Administration, Office of Oil and Gas, Kenneth A. Vagts, Director (202/586-6401). General information concerning this report may be obtained from Elizabeth E. Campbell, Director of the Natural Gas Division (202/586-5590). Questions on specific sections of the report may be addressed to the following analysts:

- Chapter 1. "The Northeast Natural Gas and Heating Oil Markets in the Winter of 1999-2000," Erika Benson (202/586-6531).
- Chapter 2. "Interruptible Gas Market in the Northeast," Erika Benson (202/586-6531).
- Chapter 3. "Natural Gas and Distillate Market Dynamics During Severe Winter Events," Aileen Alex (202/586-4255).
- Chapter 4. "Interruptions in Natural Gas Service in January–February 2000," Jose Villar (202/586-9613).
- Chapter 5. "Conclusion," William Trapmann (202/586-6408).

The overall scope and content of the report was supervised by William Trapmann. Significant analytical contributions were made by the following individuals: Mary E. Carlson, Michael J. Elias, Barbara Mariner-Volpe, Phil Shambaugh, Michael J. Tita, Jamisue Webb, and Lillian (Willie) Young. Editorial support was provided by Willie Young, and desktop publishing and graphic support was provided by Vivianne B. Couts.

Contents

Tables

Figures

2647

DOE006-0004

Executive Summary

The Natural Gas and Heating Oil Market in January-February 2000

Natural gas and distillate fuel oil[1] prices can rise rapidly during winter peak-demand months especially when stocks are low and demand increases quickly. Such was the case in the Northeast in mid-January 2000 when a sudden surge of cold weather blanketed the area, substantially increasing demand. During the week ended January 22, 2000, temperatures in the Northeast shifted from being up to 17 percent warmer than normal to 24 percent colder than normal. This large temperature shift drastically increased heating requirements at a time that the market was experiencing supply constraints. Distillate fuel oil stocks were low, and the colder weather led to distillate delivery problems as well as natural gas capacity constraints in some areas. The low temperatures and high gas demand also triggered service interruptions to natural gas customers without guaranteed (firm) service contracts, which led to purchases of other fuels, especially petroleum products. These elements came together to create rapid and extremely large price increases in the distillate fuel oil and natural gas markets.

- From January 11 to January 20, 2000, spot prices (market prices for immediate delivery) for natural gas in the New York City market rose from $2.65 to $15.34 per million Btu (MMBtu), an increase of nearly 500 percent. Natural gas prices at the Algonquin Pipeline citygate, which serves the Boston area, peaked at $12.54 per MMBtu on January 20, 2000.

- Between January 14 and February 4, 2000, New York Harbor spot prices for home heating oil rose by 133 percent while residential prices for home heating oil in New England increased by 66 percent.

The high prices and supply constraints in both markets caused great concern. Public meetings were held in February 2000 to discuss what may have caused the extreme market conditions in the Northeast and how to avoid such problems in the future. Some meeting participants pointed to interruptible gas service contracts as a major contributor to the fuel oil price spikes because of the increased demand for backup fuel when gas deliveries were suspended. Under interruptible contracts, a customer agrees to gas service without a guarantee of supplies in return for discounted rates. Roughly 10 to 15 percent of all natural gas deliveries by interstate pipeline companies (excluding transportation for other pipelines) in 1997 were on an interruptible basis.

In February 2000, Senator Joseph Lieberman asked the Department of Energy (DOE) to study how service interruptions by natural gas suppliers affected the distillate fuel oil market this past winter. To meet his request and to evaluate other factors affecting oil and gas markets, the Energy Information Administration (EIA) surveyed major gas suppliers and customers in New England and the Middle Atlantic States (New Jersey, New York, and Pennsylvania) on the extent of natural gas service interruptions during the 1999-2000 heating season and the types of fuels burned as alternatives to natural gas. Two surveys were conducted: Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000," and Form EIA-904, "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000." The respondents to Form EIA-903 were 34 natural gas companies who accounted for nearly all of the volumes delivered to end users under interruptible contracts in the Northeast in 1998, while respondents to Form EIA-904 were 97 end users in New England who received natural gas under interruptible service contracts (see Appendix B for details on the data collection methodology).

This report examines the data collected from these companies in the context of the overall energy market in the Northeast. The main purpose of the report is to provide insight into the level and duration of interruptions of natural gas service and the extent of fuel switching between natural gas and other energy markets. An earlier EIA report *The Northeast Heating Fuel Market: Assessment and Options* that addressed the ability of Northeast natural gas customers to switch to distillate fuel oil was released in May 2000. In addition, a report with policy recommendations was issued by DOE's Office of Policy in November 2000 that addressed the role of interruptible gas contracts in the New England heating oil market.

[1]Distillate fuel oil is a general classification for one of the fractions produced from crude oil. It is used primarily for space heating and on- and off-highway diesel engine fuel as well as power generation. It includes products known as No. 1, No. 2, and No. 4 fuel oils and No. 1, No. 2, and No. 4 diesel fuels.

Reductions in Natural Gas Service

An interruption of natural gas service is said to occur if gas service was discontinued to comply with a specific order by the local distribution company (LDC) or pipeline company and the service disruption was not tied to a previously determined schedule as to occurrence or duration. Thus the end user could not predict precisely when or even if a service disruption would occur. For example, customers holding interruptible service contracts would expect that service likely will be suspended sometime during the winter but the date and duration of the interruption(s) would be completely unknown.

Some energy customers contract for natural gas services for only a short period or on a seasonal basis. Service suspensions specified in seasonal or short-term contracts are not considered an interruption as long as the terms of the arrangement are not disrupted during the period of performance for the contract. Interruptions can be triggered by system operating conditions and/or temperatures. The supplier LDC or pipeline company has the right to suspend service at any time that it deems necessary to maintain system integrity or in order not to compromise service to its firm service customers. In some contracts with temperature-controlled provisions, service is suspended automatically when the outside temperature falls below a certain threshold and is not resumed until temperatures are above the threshold for a sustained period determined by the LDC.

Natural gas service may also be suspended voluntarily by customers with switchable or dual-fuel capability, even when delivery capacity is available. Some demand shifted from natural gas to distillate fuel oil during January and February 2000 because of the relative fuel prices. However, this behavior was motivated by market conditions under competition and would not be considered a service interruption.

The interruption data cited in this report are based on the volumes reported by gas suppliers on Form EIA-903. As subsequently discovered, these volumes included reductions in gas consumption because of economic switching and termination of seasonal service in addition to interrupted volumes. Although these *reported interruptions* exceed shifts from gas service due to unexpected interruptions alone, they are informative as an upper limit on volumes of fuel switching owing to gas service interruptions.

Highlights

During the peak week (ended January 22), reported gas service interruptions in the Northeast represented 49 percent of the LDCs' and pipeline companies' planned service levels to interruptible customers for that week. Overall, however, interruptions were limited and no firm service customer was interrupted. Approximately 12.4 trillion Btu or 13 percent of the total planned level of natural gas service to interruptible customers was interrupted in the Northeast during January and February 2000.

The reported gas service interruptions for customers in the Northeast with distillate fuel oil as their backup were the equivalent of between approximately 78 and 84 thousand barrels of distillate per day during the peak week. This corresponds to about 11 percent of the average daily distillate consumption in the Northeast in January 2000 and a smaller but immeasurable share of distillate consumption in the peak week. The greatest level of interruptions was focused on the third week of January, when interruptions were much greater than for any other week in January or February. Most (76 percent) of the interruptions during January and February 2000 occurred in the third and fourth weeks of January.

The estimated range of 78 to 84 thousand barrels per day of potential incremental distillate consumption is consistent with previously published estimates,[2] which ranged up to 100 thousand barrels per day for distillate fuel oil for both interruptions and economic switching combined. In fact, if the larger estimates are reliable, the 78 to 84 thousand-barrel-per-day range shows that more than 15 percent of the fuel shifting from gas to distillate is due to factors other than gas service interruptions. These distinctions have important implications for further analysis or policy formulation. Understanding motivations behind customer behavior is essential to understanding gas and fuel oil markets at critical times of the year.

Actual *purchases* of distillate fuel oil resulting from the interruptions, however, likely were less than the calculated equivalent volumes, because some customers drew down inventories slightly while others simply reduced operations or temporarily shut down. Data from a limited sample of interrupted customers in New England

[2] Energy Information Administration, *The Northeast Heating Fuel Market: Assessment and Options*, SR/OIAF/2000-03 (Washington, DC, May 2000), p. 44. Petroleum Industry Research Foundation, Inc., *What Happened to Heating Oil?* (March 2000), p. 6.

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who responded to Form EIA-904 indicate that less than half the volume of gas interrupted during January and February was replaced with distillate purchases.[3] Scaled-back operations in the Middle Atlantic, as indicated by anecdotal evidence, would have further reduced the demand for distillate fuel oil.

Additional highlights include the following:

- **Interruptions represented a larger share of planned service levels in New England than in the Middle Atlantic.** During the peak week ended January 22, reported interruptions in New England were roughly equal to planned service levels, meaning that virtually no gas was delivered under interruptible service contracts. In contrast, interruptions in the Middle Atlantic during that week were only 39 percent of planned service levels. This relative pattern is present during the full 2 months, although at lower levels. Interruptions totaled 3,786 billion Btu in New England and 8,578 billion Btu in the Middle Atlantic, representing 28 percent and 11 percent, respectively, of planned service levels to interruptible customers in the region.

- **Both large-volume and small-volume customers who responded to the EIA-904 maintained a fairly constant level of distillate inventories.** Throughout the 8-week period, the large customers, which included power producers, maintained their inventories within a narrow range: 90 percent full at its maximum on the week after the largest interruptions and 79 percent full in late February. On average the smaller customers maintained weekly inventories at 68 percent of their distillate capacity with 79 percent as the high and 63 percent as the low during the period.

- **The large-volume and small-volume customers have contrasting distillate inventories and inventory capacities.** Based on maximum potential interruption levels, the small customers had 14.3 days of distillate storage capacity available and 9.8 days of distillate inventories on hand. In contrast, large customers had only 3.7 days of storage capacity and 3.1 days of inventory.

- **Customers in the education, health, and housing/lodging industries accounted for 30 percent of the interruptions known by industry type[4] in the Northeast during January and February 2000.** Customers in these categories relied less heavily on distillate as a backup fuel and had more inventories on hand than the average interrupted customer. Like other customers interrupted, though, they made purchases to replace fuels burned during the interruption in natural gas service in order to maintain onsite stocks.

This study provides better information than previously available on the magnitude of fuel switching from natural gas to alternative fuels. It also contains information on customer behavior during the winter heating season, including times of intense demand when some portion of gas service is not available. This information highlights the complex interactions between interruptible gas service and other fuel markets. Customer reactions to gas service interruptions reflect varying operational objectives and economic circumstances.

The additional demand in the distillate market from interrupted gas customers may not have been as large as previously thought. However, if supplies are tight, additional purchases may have a disproportionate price response, so even small volumes of additional purchases may be difficult to accommodate. Further, although interruptible contracts may have had a limited role in recent fuel oil price spikes, that influence may increase over time as gas markets are expected to expand relative to the distillate fuel oil markets, especially heating oil, in the Northeast.

[3]The findings from the EIA-904 customer survey are provided as illustrative, but they are not statistically valid for the overall regional market.

[4]About 50 percent of the volumes reported by respondents to Form EIA-903 could be categorized by primary business of the customer.

1. The Northeast Natural Gas and Heating Oil Markets in the Winter of 1999-2000

This report was undertaken at the request of U.S. Secretary of Energy Bill Richardson to assess the impact of interruptible natural gas contracts on heating oil demand in the Northeast. An earlier report with policy recommendations was issued by the Department of Energy's Office of Policy in November 2000 that examined the effect of interruptible contracts in New England. The current report expands the geographic scope of the analysis by including New Jersey, New York, and Pennsylvania and presents a more comprehensive assessment of gas service interruptions, the responses of different types of customers, and the effects on the distillate fuel oil market.

Overview

Price spikes and petroleum product shortages dominated the energy market in the Northeast for several weeks in the winter of 1999-2000 as a sudden drop in temperatures led to a sharp increase in demand for heating fuels. Despite generally warmer-than-normal temperatures during much of last winter, the Northeast had a period of cold weather from mid-January to early February 2000 during which daytime temperatures ranged between 10 and 20 degrees Fahrenheit for over a week in many areas (Figure 1).

The colder weather increased demand for energy in all end-use markets. Residential and commercial consumers increased their use of distillate fuel oil[1] to heat their homes and businesses and power companies increased their use to meet electricity demand. Demand for distillate fuel oil was expanded further as power companies and industrial customers with dual-fired facilities increased their use of distillate fuel oil by switching from natural gas, either as required by their gas supply contracts or to avoid the higher price of natural gas.

The unexpected rapid increases in demand for distillate fuel oil coincided with serious delivery problems. Icebound rivers and high winds along the New York, Connecticut, and Massachusetts coastlines hindered the arrival of new distillate fuel oil into New York and Boston harbors. In part, because of weather-related delays in docking and unloading tanker and barge deliveries, the new supply that did arrive commanded higher prices. Also, supply deliveries within the region were impeded by icy roads that slowed truck deliveries.

The colder weather also strained the capacity of the natural gas pipeline system in the Northeast. The increase in heating demand caused natural gas deliveries to expand to the peak-day sendout capacity of a number of natural gas systems.[2] This forced natural gas companies to suspend deliveries to a number of interruptible customers as per the service contract (see box, "Defining an Interruption," p. 2), so that suppliers could meet the demand of their firm service customers and maintain system capability. In addition, several pipeline companies issued operational flow orders (see box, "Operational Flow Orders," p. 3) at locations serving the Northeast, putting further pressure on spot market prices.[3]

Natural Gas Spot Prices at Northeast Markets Reached High Levels in January 2000

Natural gas spot prices spiked sharply in the Northeast as cold weather blanketed much of the area. Daily spot prices show the extent by which weather was a factor in creating these rapid price spikes. Natural gas spot prices at the Boston citygate[4] opened for the month of January at $2.77 per million Btu (MMBtu) and remained less than $3.00 until January 13 (Figure 2). Then prices surged, peaking on January 20, during the height of the severe weather, at a high of $12.54 per MMBtu, and stayed above $9.00 for the following 3 days.

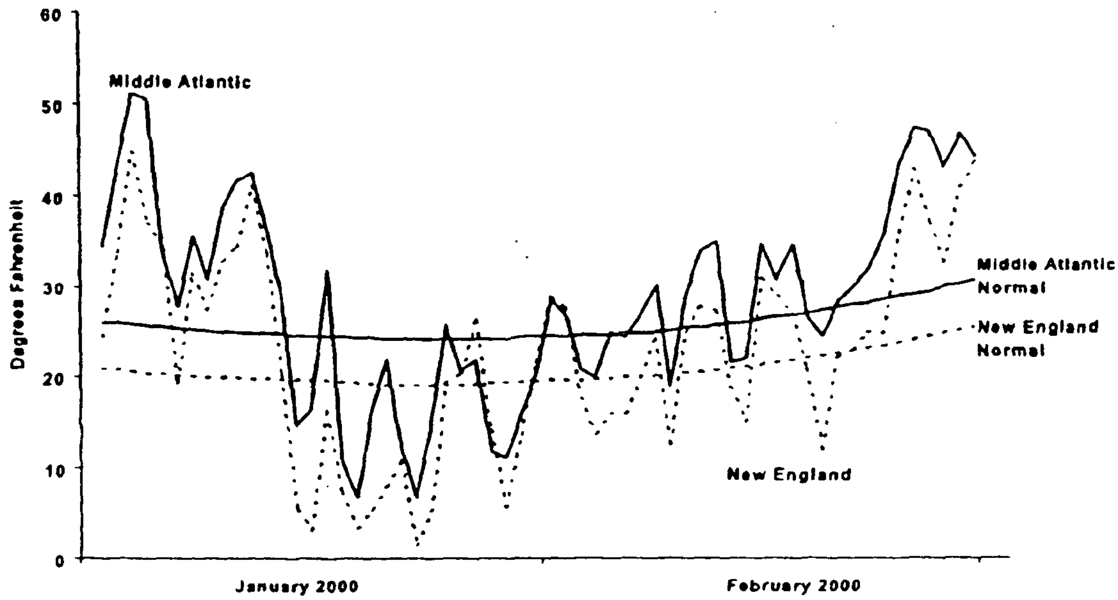
[1] The "distillate fuel oil" designation comprises Nos. 1, 2, and 4 heating oils and diesel fuels. Generally, home heating oil is a high-sulfur No. 2 fuel oil. No. 1 distillate oil and No. 2 low-sulfur diesel fuel can also be used for home heating if necessary and available. Price usually precludes their normal use for these purposes.

[2] For example, regional deliveries in New England hit an unprecendented sendout of 3.4 billion cubic feet per day.

[3] Spot market prices, also known as "cash prices," are the market prices for immediate deliveries of the product.

[4] The Algonquin citygate spot price (as reported by Financial Times in the *Gas Daily*) is used as the approximate measure for the Boston citygate.

Figure 1. Daily and Normal Temperatures in New England and the Middle Atlantic States, January and February 2000



Note: Daily temperatures were computed from daily observations available from the National Climate Data Center website and weighted by housing units within a region. Normal is the 30-year average temperature.
Source: Energy Information Administration, Office of Oil and Gas, derived from National Climate Data Center data (http://www.ncdc.noaa.gov/ol/climate/climatedata.html).

Defining an Interruption

In this analysis, an interruption of natural gas service is said to occur if the end user discontinued gas consumption to comply with a specific order by the local distribution company (LDC) or pipeline company and the service disruption was not tied to a previously determined schedule as to occurrence or duration. Thus the end user could not predict precisely when or even if a service disruption would occur. For example, customers holding interruptible service contracts would expect that service would likely be suspended sometime during the winter but the date and duration of the interruption(s) would not be known beforehand.

Some interruptible customers contract for natural gas services for only a short period or on a seasonal basis. Service suspensions specified in seasonal or short-term contracts generally should not be considered an interruption as long as the service under the arrangement is not disrupted during the period of performance for the contract. Natural gas service also may be suspended voluntarily by customers with switchable or dual-fuel capability, even when delivery capacity is available, because of the relative fuel prices. Survey data presented in this report are *reported interruptions*, based on Form EIA-903, which included reductions in gas consumption because of economic switching and termination of seasonal service in addition to interrupted volumes. The additional distillate fuel oil demand from customers who voluntarily choose to switch from natural gas despite the availability of gas service could be significant and would have the same impact on petroleum markets as equivalent demand owing to interruptions. Although some of this activity was reported by respondents to Form EIA-904, data are not available to quantify reliably the extent of seasonal or voluntary fuel switching in this analysis.

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Operational Flow Orders

When FERC Order 636 was instituted in 1993 and open access became the norm, the Federal Energy Regulatory Commission (FERC) recognized that pipeline operators needed a mechanism that would allow them to maintain the operational integrity of their system during periods of potential flux and when the system is under stress. Conditions such as extreme weather, unscheduled downtime on critical parts of the system, and extreme imbalance situations are some of the reasons pipeline companies cite as the need for such short-term control.

Operational flow orders (OFOs) (also called system emergency orders or critical period measures) are the mechanisms put in place to permit this control. In effect, these orders permit the pipeline operator during emergency situations to restrain shipper activities and to curtail services that could result in imbalances and service interruptions. For instance, OFOs allow the operator to reduce or eliminate flow tolerances and require shippers to maintain a strict daily balance between receipt and delivery volumes. The OFO also may restrict or eliminate such services as intraday nominations, the use of secondary receipt and delivery points, firm storage withdrawals, and interruptible storage services. As an enforcement measure, pipeline companies can exact penalties for violations. Under an OFO, pipeline companies generally perform to the level of their contract obligations, but the strict operational inflexibility does tend to restrict the flow volume in practice.

Despite their utility, OFOs are controversial. Some have suggested that the direct consequence of measures taken under OFOs during the past few years was to lessen short-term trading and shipping flexibility on the part of customers. Also many critics maintained that pipeline operators were given too much discretion regarding what constitutes an OFO situation and that operators had incentives for maintaining the OFO for longer than is needed.

In an effort to minimize the use of OFOs, FERC issued new rules that require each pipeline company to take system-wide measures to ensure that OFOs are used for only the most serious circumstances. In FERC Order 637, issued in February 2000, pipeline companies were directed to change their tariffs to incorporate these new requirements, or to explain and describe how current tariff and operating procedures are consistent with the new requirements. Each pipeline company tariff must now include:

- Clear, pipeline-specific standards, based on objective operational conditions, for when OFOs begin and end
- A stated obligation to provide information about the status of conditions during an OFO as soon as possible
- What steps or remedies will be taken before issuing an OFO so as to provide as much advance warning as possible
- Standards for different levels or degrees of severity for OFOs so that penalties correspond to degree of emergency
- Specific reporting methods for providing later information on why an OFO was issued and lifted.

Pipeline companies can implement these changes into their tariffs on an individual basis: there are no general requirements in regards to specific language that must be used. FERC also ruled that pipeline companies must credit all revenues from penalties (net of cost), including OFO penalties, to shippers.

The same rapid increase and decrease in natural gas spot prices occurred in the New York City market (Figure 3).[5] Prices at the New York citygate peaked at more than $15.00 per MMBtu on January 20, 2000, and traded between $8.00 and $10.00 for several days during the period. The average spot price in January 2000 was $5.98 per MMBtu, which is 57 percent higher than the 4-year average for the month of January and more than double the average price in January 1998. In contrast to the previous three winters (beginning in 1997), during which spot prices declined in the latter part of the season, spot prices remained relatively high in the last 2 months of the 1999-2000 heating season.

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[5]The prices for gas traded at Transco Zone 6 in New Jersey are used as indicators of spot prices for the New York citygate. See *Gas Daily* (Arlington, VA: Financial Times).

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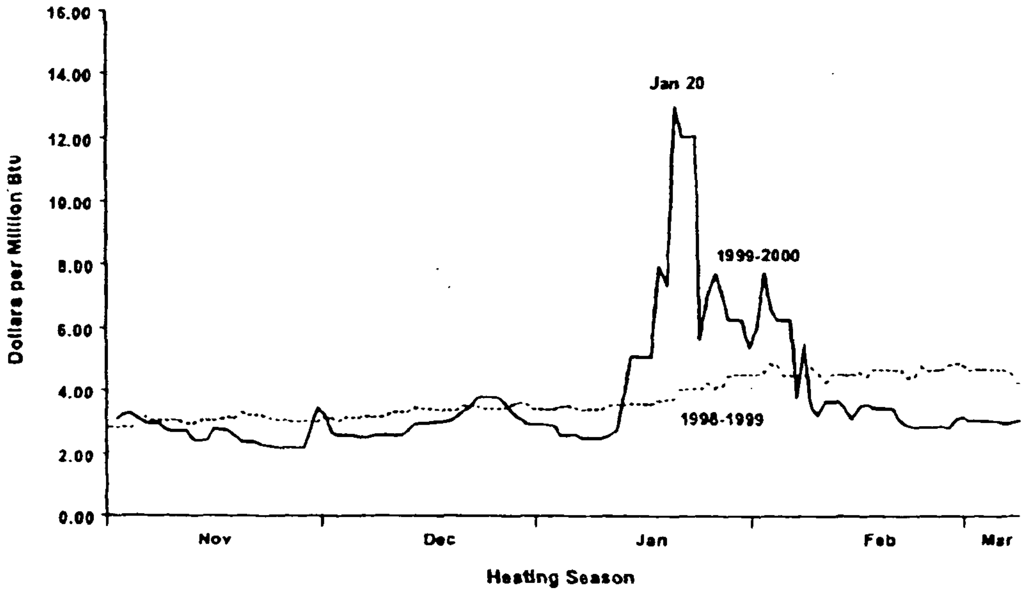
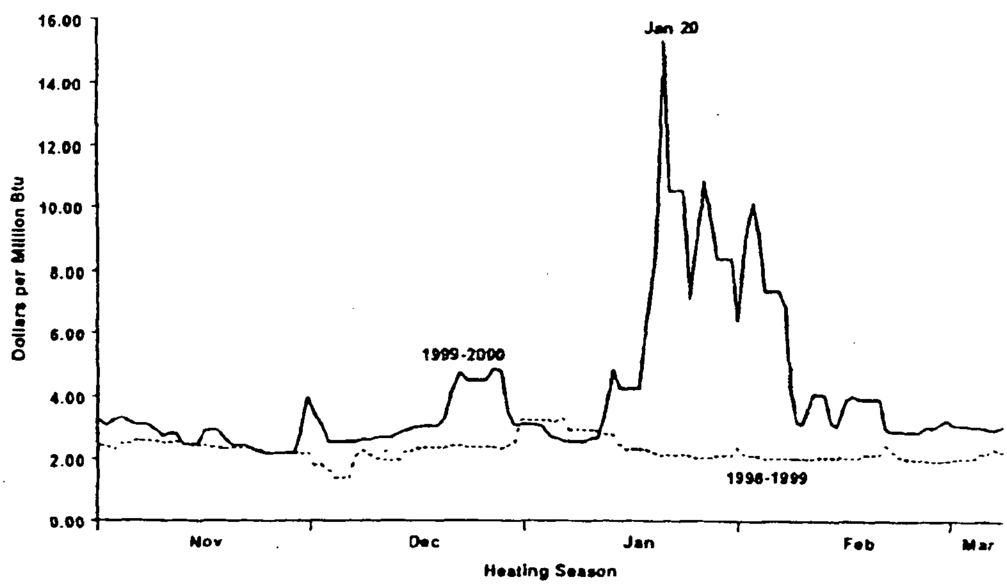
Figure 2. Spot Price of Natural Gas at the Boston Citygate, Heating Seasons 1998-1999 and 1999-2000



Source: Algonquin citygate spot price, Financial Times, *Gas Daily* (various issues).

Figure 3. Spot Price of Natural Gas at the New York Citygate, Heating Seasons 1998-1999 and 1999-2000



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Natural gas consumption in January and February 2000 also increased by a significant percentage in both New England and the Middle Atlantic states. For example, for both January and February, consumption of natural gas for all sectors was 13 percent higher in Connecticut than year-earlier levels and 4 percent higher in Pennsylvania. The increased consumption also resulted in extensive use of underground storage stocks.

About 3,101 billion cubic feet (Bcf) of working gas storage[6] was on hand at the end of October 1999, which was 112 Bcf more than the average (2,989 Bcf) for the previous five years (1994-98) and the second-highest level in 7 years.[7] Net withdrawals during the next 2 months were relatively small (517 Bcf or 21 percent below the 5-year average of 625 Bcf). But net withdrawals from U.S. natural gas storage facilities for January 2000 exceeded the previous single-month record by almost 30 Bcf as 780 Bcf was taken from storage to meet demand. The Consuming East region[8] reported net withdrawals of 527 Bcf or 67 percent of the January total. The week of January 28, 2000, was the largest recorded weekly drawdown from eastern storage facilities with 158 Bcf withdrawn. The cold weather carried over into the first week of February, and net withdrawals for February in the Consuming East region were 289 Bcf or 13 percent more than withdrawals in February 1999. The relatively high prices that continued throughout most of the heating season probably contributed to the increased utilization of storage during a generally warmer-than-normal winter, as companies chose to use their lower-cost inventories as they expected prices to decline in time to replenish stocks.

Low Distillate Stocks Set the Stage for Heating Oil Price Spikes in January 2000

U.S. distillate inventories (including both heating oil and diesel fuel) were at typical stock levels of 145 million barrels on October 1, 1999,[9] but were well below normal by the end of December and even more so by late January. From December 17, 1999, to January 14, 2000, distillate stocks at the primary level fell by 10 million barrels to 119 million barrels, which was 5 million barrels below the low end of the normal range[10] despite warmer-than-normal temperatures. At the time, it was suggested that Y2K precautionary stocking at the consumer level was a possible cause for the sharp decline in supplier stocks prior to the onset of cold weather.

This pattern was also seen in the New England and Central Atlantic states.[11] The pace of the distillate stock drawdown was remarkable, particularly in New England, where stocks fell from more than 13 million barrels in early December to less than 4 million barrels by late January. Stocks in New England were consumed at the rate of 289 thousand barrels per day in December and 363 thousand barrels per day in January, implying that just over 12 days of supply remained in storage at the end of January. In the Central Atlantic, the level of stocks was much higher, and the pace of decline was not as dramatic, but went on longer, falling from almost 33 million barrels at the beginning of November to 18 million barrels by late January. Daily consumption rates in the Central Atlantic averaged 667 thousand barrels in December and 694 thousand barrels in January, with 26 days of supply remaining in storage at the end of January.

Refinery outages at the end of the week of January 21 resulted in a temporary loss of new supply, and sent more buyers into the distillate spot market. When refiners cannot produce enough supply to meet their contracts, customers must enter the spot market to purchase the product from others. Weekly data indicate that for the 4-week period ending February 4, 2000, East Coast distillate stocks fell by almost 20 million barrels or 41 percent during that time, and some terminal outages occurred.

The rapid depletion of stocks led to progressive increases in spot market prices. Low distillate stocks leave little cushion to absorb sudden changes in supply or demand that increase the possibility of price runups. Between January 14 and February 4, 2000, New York Harbor spot prices for home heating oil rose from $0.76 to $1.77 per gallon,[12] a 133-percent increase. Retail prices of home

[6] Working gas is the volume in an underground storage reservoir available for withdrawal. A volume of gas (known as base gas or cushion gas) is needed as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates.

[7] Energy Information Administration, *Natural Gas Weekly Market Update* (November 8, 1999). Web Site: http://www.eia.doe.gov.

[8] A regional storage designation used by the American Gas Association. It includes all states east of the Mississippi River except Alabama and Mississippi and also includes Iowa, Nebraska, and Missouri.

[9] Data for distillate stocks and consumption are from the Energy Information Administration Oil and Gas Information Research System, November 1, 2000.

[10] Normal range estimated based on: Energy Information Administration, *Weekly Petroleum Status Report*, DOE/EIA-0208(2000-2) (Washington, DC, January 14, 2000), Table A1.

[11] The Central Atlantic includes Delaware, Maryland, New Jersey, New York, Pennsylvania, and the District of Columbia.

[12] There are 42 gallons of heating oil per barrel.

heating oil and diesel quickly rose in response. In the 3 weeks between January 17 and February 4, New England residential heating oil prices rose by 66 percent from $1.18 to $1.97 per gallon. During the same period, retail diesel fuel prices rose by 47 percent from $1.44 to $2.12 per gallon.

The market pressures were resolved in February 2000 with the arrival of new supply and a return to warmer weather. Most of the new supply came from imports attracted by the high prices. Prices receded both in the spot markets and at the retail level, although high crude oil prices continued to keep distillate fuel oil prices high relative to the previous year.

Concerns About High Prices and Supply Constraints

The high prices and supply constraints in the Northeast during January and February 2000 raised many questions and caused great concern last winter, particularly since a large percentage of households in the region, especially in New England, use oil as their main heating fuel. In February 2000, Secretary of Energy Bill Richardson held a series of public meetings with various government, industry, and consumer representatives to discuss what may have caused the extreme market conditions in the Northeast and how to avoid such problems in the future. During the meetings, some participants pointed to interruptible gas service contracts as a major contributor to heating oil price spikes because of the increased demand for backup fuel when gas deliveries are suspended. Under interruptible contracts, a customer agrees to gas service without guaranteed performance in return for discounted rates. In many if not most cases, customers turn to distillate fuel oil or another type of fuel oil as an alternative fuel when gas service is disrupted.

Also in February 2000, Senator Joseph Lieberman asked the Department of Energy to study the impact of service interruptions by natural gas suppliers on the home heating oil market in the Northeast this past winter (see Appendix A). Specifically, he asked for an investigation of "the extent of interruptible natural gas contracts and the level of new demand they may be adding to the heating oil market in the Northeast." He also asked:[13]

- At what point do natural gas contractors refuse service to interruptible gas contract-holders?
- How often in the recent past have users of interruptible gas contracts created a significant unforeseen demand on home heating oil in the Northeast?
- What other backup fuels do interruptible contract users utilize?

To meet Senator Lieberman's request and to evaluate concerns raised at the public meetings Secretary Richardson directed DOE's Office of Policy and the Energy Information Administration (EIA) to undertake a study of how service interruptions by natural gas suppliers affected the home heating market this past winter. In response, EIA surveyed major gas suppliers and customers in the Northeast on the extent of natural gas service interruptions during the 1999-2000 heating season and the types of fuels burned as alternatives to natural gas.[14] Data compiled from companies in New England were used as the basis for a report with policy recommendations issued by DOE's Office of Policy in November 2000 that addressed the role of interruptible gas contracts in the New England heating oil market.[15] An earlier EIA report that addressed the ability of Northeast natural gas customers to switch to distillate fuel oil was released in May 2000.[16]

Report Purpose and Structure

This report expands upon DOE's and EIA's two earlier reports and examines natural gas interruptions in the context of the overall energy market in the Northeast. The current report is intended to provide a more

[13]In addition, Senator Lieberman asked if interruptible gas contracts threaten the stability of the home heating oil market and if so what steps should be taken to alleviate the problem (see Appendix A for a copy of his letter). Such policy questions are beyond the scope of the Energy Information Administration and are not addressed in this analysis.

[14]In order to assess the gas interruptible market, EIA developed two surveys: Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000," and Form EIA-904, "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000." The respondents to Form EIA-903 were 34 natural gas companies who accounted for 94 percent of the volumes delivered to interruptible end users in the Northeast in 1998, while respondents to Form EIA-904 were 97 end users in New England who receive natural gas under interruptible service contracts (see Appendix B for details on the data collection methodology).

[15]U.S. Department of Energy, *The Role of Interruptible Natural Gas Customers in New England Heating Oil Markets: A Preliminary Examination of Events in January-February 2000*, DOE/PO-0063 (Washington, DC, November 2000).

[16]Energy Information Administration, *The Northeast Heating Fuel Market: Assessment and Options*, SR/OIAF/2000-03 (Washington, DC, May 2000).

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complete picture of regional interruptions in gas service, the responses of interruptible gas customers, and impacts on the distillate fuel oil market. The geographic scope of the study has been extended beyond New England to include New York, New Jersey, and Pennsylvania.[17] An expanded geographical scope and more complete data are important because of the relatively large volumes of interruptible gas service and sizeable distillate market in the larger region, and because Senator Lieberman's request for a DOE study applied to the entire Northeast region. The report also provides more detail on interruptions by type of customer, such as power plant vs. small commercial facility. In addition, the analysis compares the January–February 2000 price spike with other recent price spikes to determine the factors common to each of the events and to provide a framework for better understanding the impact of gas service interruptions on distillate fuel oil markets.

The report has five chapters and four appendices. Chapter 2 provides background information on natural gas markets in the Northeast and the role of interruptible contracts in the region's energy market. It also discusses the types of alternative fuels used by companies when gas service is interrupted. Chapter 3 examines the main factors that affect heating oil and natural gas prices by comparing market events during other periods of sharp price increases in recent years. It looks at such factors as weather, fuel demand, supply disruptions, stock levels, and service and delivery constraints. Chapter 4 provides an analysis of the information derived from EIA surveys of gas suppliers and customers, and Chapter 5 presents a summary of market implications. The four appendices provide supplemental information and details on the methodology used in the analysis.

[17] In this report, the Northeast comprises the New England and Middle Atlantic states (Census Divisions 1 and 2). New England (Census Division 1 and Petroleum Administration for Defense District (PADD) 1a) includes Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The Middle Atlantic (Census Division 2) includes New York, New Jersey, and Pennsylvania.

2. Interruptible Gas Market in the Northeast

Introduction

Energy end users include residential and commercial customers as well as industrial firms and electric utilities. These customer groups have different energy requirements and thus quite different service needs. In the natural gas market, consumers contract for either firm or interruptible service. Residential and small commercial customers such as households, schools, and hospitals use natural gas primarily for space and water heating and need a reliable supply. Such customers require on-demand service with no predetermined quantity restrictions, known as firm service. In contrast, larger commercial, industrial, and electric utility customers often have fuel-switching or dual-fuel capabilities and can receive natural gas through a lower priority and less expensive service known as interruptible service. Energy supply reliability can be effectively handled at the customer level by the ability to switch quickly to an alternative fuel.

The infrastructure for transporting and delivering natural gas is designed and operated primarily to meet the need for firm service. Because the peak demand for natural gas tends to be seasonal, interruptible service contracts allow pipeline and distribution system operators to increase utilization of their fixed assets and better manage costs of service on average. These arrangements allow operators to maximize economic efficiency by meeting the needs of their committed firm service customers while providing service during off-peak periods to interruptible and seasonal customers. At the same time, these arrangements provide opportunities for large-volume energy consumers such as industrial firms and electric generators to attain lower-cost energy supplies. However, the resulting prevalence of dual-fired equipment establishes a framework in which fuel switching is expected, which in turn has the potential for significant impact on multiple fuel markets.

This chapter provides background information on natural gas markets in the Northeast to establish a framework for understanding the role of interruptible contracts in the region's energy market. The discussion includes a description of interruptible contracts and of the alternative fuels used by companies when gas service is interrupted. Service interruptions generally result in the use of onsite stocks of backup fuels as a replacement for natural gas, purchases of backup fuels, or a reduction in operations.

Characteristics of the Northeast Natural Gas Market

The Northeast Region is the most highly populated of the regions[1] and consumes the most energy. Yet natural gas represents a somewhat lower proportion of total energy consumed: 21 percent versus a national average of about 24 percent. However, this share has grown over time; between 1990 and 1997, natural gas consumption in the Northeast grew at a faster average annual rate than overall energy use, 4.9 percent versus 1.2 percent. This growth in natural gas consumption, as well as the spread between natural gas and overall energy use, was among the highest of the regions.

The greatest demand for natural gas in the region occurs during the winter. Overall, the Northeast is the third coldest region and has some of the coldest weather in the nation along its northern tier. Withdrawals from storage are necessary to meet peak demand, since total pipeline capacity entering the region plus regional gas production account for only about two-thirds of the region's peak demand.

Natural gas consumers in the Northeast must rely on an extended interstate pipeline system to bring supplies from outside the region because local production is quite limited. Regardless of the source of the gas, however, its delivery during the heating system depends on a relatively fixed pipeline system. The bulk of the natural gas supply arrives through a single corridor from the Southwest through Pennsylvania and New Jersey, although recent construction projects have substantially increased the supply capability of the interstate pipelines entering the region from Canada. The supply flexibility in the Northeast is more limited than in other regions, which are both closer to the major producing regions in the Southwest and western Canada and which have multi-directional access to storage and other pipeline

[1] The six regions examined in this portion of the analysis were the Northeast (Federal Regions 1, 2, and 3), Southeast (Federal Region 4), Midwest (Federal Region 5), Southwest (Federal Region 6), Central (Federal Regions 7 and 8), and Western (Federal Regions 9 and 10). Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998). The Northeast region, as defined in the *Deliverability* report, differs from the Northeast regional designation used elsewhere in this report in that it includes the District of Columbia and four additional states, Delaware, Maryland, Virginia, and West Virginia.

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supplies. Supplies within the region reach consumers primarily through local distribution companies (LDCs). An extensive distribution network of pipelines is in place in much of the region (except for Maine, New Hampshire, and Vermont).

End-Use Consumption

Residential and commercial natural gas consumption (mostly space-heating demand) accounts for the largest share of the regional natural gas market (59 percent in 1999). Industrial and electric generation sectors represent 33 and 8 percent, respectively (Figure 4). Consumption by sector varies throughout the year. Daily residential use during February is more than seven times the average in August, the month with the lowest gas consumption (Figure 5). As consumption of natural gas increases, capacity into the region is utilized to a greater extent for short periods of time.

Although natural gas can be stored in the vicinity of major consumption markets, the nature of the gas system causes much of the supply to be provided on a "just-in-time" basis. Limited capability for onsite storage at a customer's location means that the system must meet customer requirements under a wide range of operating conditions with an upper limit on flow potential. Therefore, this system of just-in-time supply may make unexpected and significant spikes in demand difficult to satisfy.

Natural Gas Supply

Sources of gas in the Northeast include production, imports, transported volumes, and storage withdrawals (Figure 6). Production of natural gas in the region is limited to states in the Middle Atlantic Census division.[2] Produced volumes are rather small: 8 percent of the total volume delivered to end users in the Middle Atlantic in 1999 and 6 percent of total end-use deliveries in the Northeast as a whole. The Northeast received 59 percent of current supply (excluding storage)[3] from other U.S. regions, 18 percent from pipeline imports of Canadian gas, and 3 percent from liquefied natural gas (LNG) imports that were delivered to Massachusetts from overseas. New England, in particular, is highly dependent on flows from other U.S. regions, with 78 percent of current supply from the domestic transportation network. Although LNG imports represent only a small part of Northeast regional supply, they comprised 9 percent of New England supplies in 1998 and 19 percent in 1999. LNG volumes more than doubled in 1999 to129 billion cubic feet (Bcf) compared with 62 Bcf in 1998.

The key issue for the natural gas infrastructure is the ability of the supply system to meet gas requirements at times of peak demand. Although delivery capability depends primarily upon the pipeline infrastructure, there is some operational flexibility that can expand deliverability although usually at increasing costs. System operators rely on various methods to manage demand and obtain suitable supplies. To ensure delivery to customers who contract for firm service, supplies from the pipeline system may be supplemented with inventories drawn from regional underground storage facilities. Storage withdrawals require prior injections so they do not add to net supplies for the entire year. However during the heating season they are a key element of supply used to meet elevated demand levels. As demand rises to peak levels, maintaining gas service to firm customers often requires the use of increasingly costly measures, such as LNG storage and propane. Demand can be managed by removing some users from the system during peak periods, usually under the terms of interruptible service contracts.

Interstate Pipeline Capacity

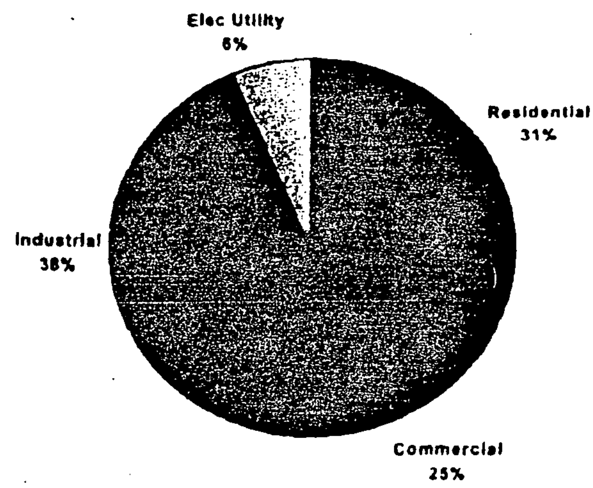
The Northeast market has been the target of several pipeline construction projects in recent years. Pipeline capacity entering the Northeast region grew by 13 percent from 1996 to the end of 1998. Expansion continued in 1999 with the completion of nine projects providing 556 million cubic feet (MMcf) per day of new capacity into the region, or about 0.2 trillion cubic feet per year, and another 984 MMcf per day within the region. More than a third of the added capacity in 1999 (547 MMcf per day)[4] was associated with the Maritimes and Northeast Pipeline and Portland Gas Transmission System projects, which transport Canadian gas to the New England area. Those two projects alone increased overall pipeline capacity into the Northeast by 4 percent. The Maritimes and Northeast Pipeline establishes a link

[2]The Middle Atlantic (Census division 2) includes New York, New Jersey, and Pennsylvania.

[3]*Current supply* is the sum of production, imports, and net inflow from other domestic regions. It excludes storage withdrawals.

[4]Capacity of the new pipelines total 578 MMcf per day (MMcf/d), but part of the project included conversion of a 31-MMcf/d line back to oil use, so the net gain in new capacity is 547 MMcf/d

Figure 4. Shares of Natural Gas Deliveries to the Northeast by Sector, 1999



Total End-Use Deliveries = 3.04 Trillion Cubic Feet

Source: Energy Information Administration, *Natural Gas Annual 1999*.

Figure 5. Daily Average Natural Gas Consumption in the Northeast by Sector by Month, 1990-1999

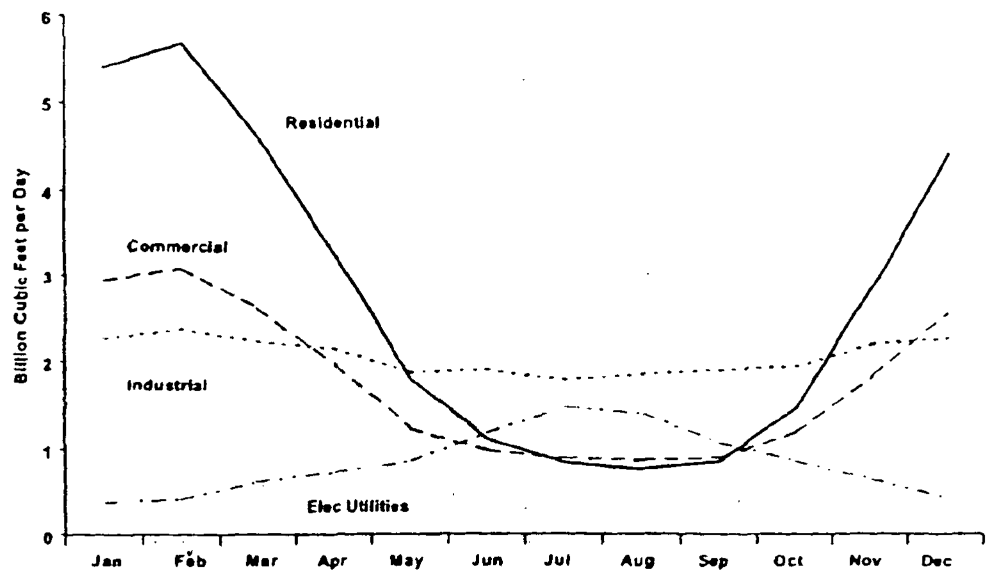
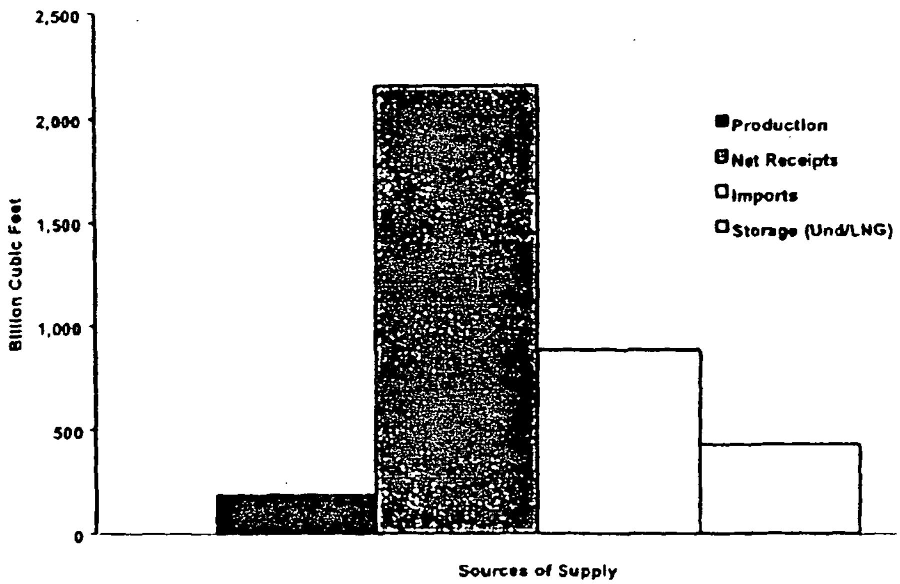


Figure 6. Distribution of Natural Gas Supply Sources in the Northeast, 1999



Source: Energy Information Administration, *Natural Gas Annual 1999*.

between the Sable Offshore Energy Project in the northern Atlantic and New England markets. The Sable Island project has about 3 trillion cubic feet of recoverable gas resources and is designed to supply about 530 MMcf per day to U.S. and Eastern Canadian markets, with about 400 MMcf per day directed to New England. With the Maritimes & Northeast Pipeline, import capacity to the Northeast from Canada increased to 2,956 MMcf per day in 1999, up 24 percent from 2,393 MMcf per day in 1997.

The dependence on volumes transported into the region underscores the importance of transportation capacity. In 1999, the interstate pipelines entering the Northeast region had the capability to transport 13,090 MMcf per day, with much of the capacity directed to New York City, Boston, Massachusetts, and the Philadelphia/Trenton area (Figure 7). The states of Pennsylvania and New York are the key transit points for gas deliveries within the region. These states have the largest underground storage capacity in the region, as well as some of the largest entering and exiting capacities and annual flow rates to New England.

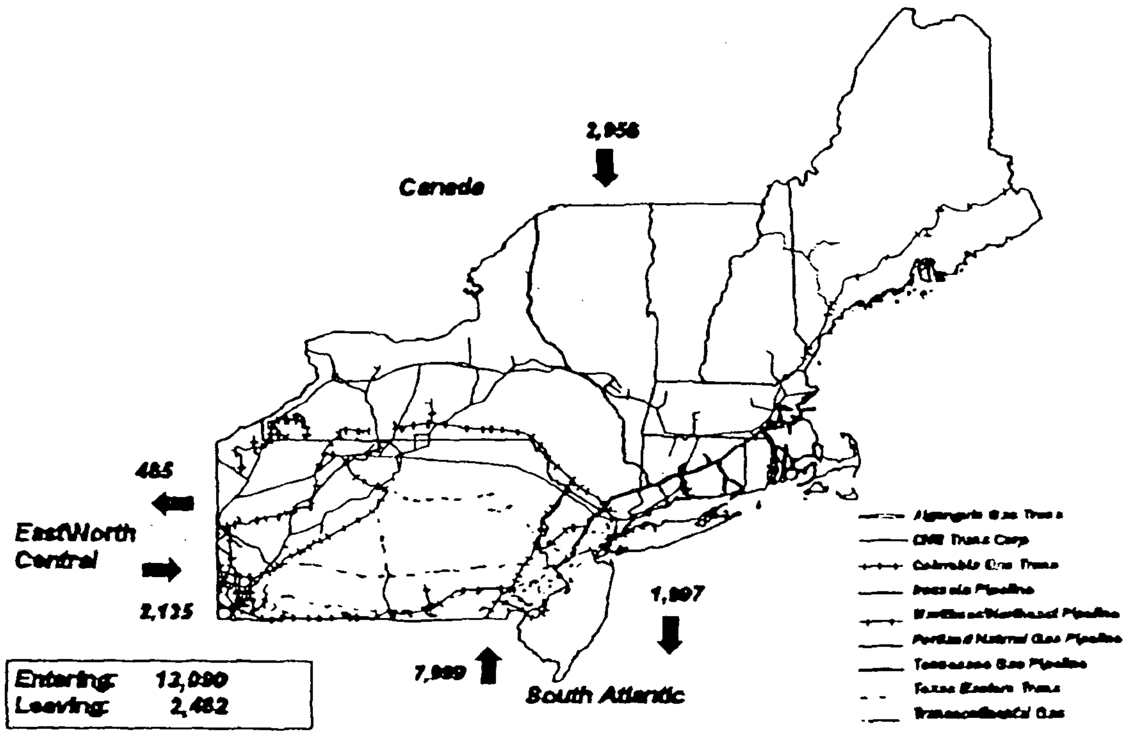
Existing pipeline capacity in many parts of the Northeast region is adequate to meet current firm-service demand. However, most pipelines are heavily, if not fully, utilized during periods of peak demand. In certain cases, line-packing[4] is used to augment capacity during a time of peak demand to ensure that firm service is met.

About three-quarters of the capacity into the region is supplied somewhat equally by three long-distance trunkline systems: Transcontinental Gas Pipe Line Corporation, Texas Eastern Transmission Corporation, and Tennessee Gas Pipeline Company. In 1996, the utilization rates (daily flow as a percent of estimated capacity) on these pipeline systems as they entered the region averaged 80 percent. Tennessee Gas Pipeline had the highest utilization (90 percent) and the highest actual volume (2.8 Bcf per day) into the region. These pipeline systems bring gas from the producing areas of Texas, Louisiana, and the Gulf of Mexico to the Northeast through the southeastern states to Pennsylvania.

The largest major regional pipeline companies, CNG Transmission and Columbia Gas Transmission, have an

[4]Line-packing is a method to increase pressure in the pipeline. The maximum design pressure of the pipeline can be increased to allowable standards as a temporary source of extra supply.

Figure 7. Interstate Natural Gas Pipeline Capacity for the Northeast, 1999
(Million Cubic Feet per Day)



Note: Figure shows major lines. Capacity values show total regional flow capacity.
Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, as of December 1999.

extensive network of local delivery points and pipeline interconnections that supply many of the major local distribution companies in the region. By far, the largest flows into the region are from the U.S. Southwest producing area via the Southeast into Pennsylvania and New Jersey.

In addition to the pipelines entering the region, several smaller interstate pipeline companies operate entirely within the region. Foremost among these is Algonquin Gas Transmission Company, which has the capacity to move 1.2 Bcf per day from New Jersey into New York. Algonquin, with 1,056 miles of trunk transmission lines, distributes the gas received in New Jersey to New York, Connecticut, Rhode Island, and Massachusetts.

Storage

Storage gas is essential for providing reliable service. On average, net storage withdrawals provide 25 percent of more of Northeast natural gas consumption during the winter season. However, reliance on storage can be much higher in some peak demand periods. Two types of gas storage are currently in use in the Northeast: underground sites—primarily, depleted oil and gas reservoirs[5]—and above-ground LNG facilities. Depleted oil and gas reservoirs generally take 5 months or more to fill and can be emptied over a 3-month period. LNG storage has a higher deliverability (or drawdown rate

[5]Salt cavern sites are becoming common in other regions of the country, but the only one in the Northeast as of December 1998 was the N.Y. State Electric & Gas facility in Seneca county.

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relative to stock levels), but it is used only for short durations, generally to satisfy peak periods of extreme demand, owing to its relatively higher cost and slow refill capability.

The Northeast has a total storage capacity of about 966 Bcf and a working gas capacity[6] of almost 510 Bcf (Table 1). The primary component of this storage capacity, 95 percent, is in underground facilities in New York and Pennsylvania. However, because of the relatively slow maximum rate at which gas can be withdrawn from these facilities compared with LNG, they account for only 72 percent of the region's maximum daily deliverability. Because of drawdown rates, LNG storage units contain only 8 days of supply when filled, as compared with more than 57 days of supply available on average from the underground units when they are filled.[7] Compared with other market areas, the Northeast makes the most extensive use of LNG. The peak-day deliverability of LNG in the region, 3.4 Bcf per day, is 39 percent as large as the total daily deliverability from underground storage facilities.

Gas storage allows supplies to be acquired during periods of slow demand and subsequently delivered to end users during peak demand periods. However, storage utilization strategies by LDCs during the winter tend to be somewhat complex. For LDCs, which generally are responsible as the "supplier of last resort,"[8] their withdrawal strategies often reflect their concerns about being able to meet demand surges in the event of a late season cold snap. A consequence of such a strategy is that early season withdrawals are reduced in favor of later withdrawals and may lead to higher prices in the short run.

Ideally, gas storage facilities are sited close to major markets in order to minimize the time and expense required to move supplies to consumers and avoid potential transportation bottlenecks when demand surges. Proximity of storage facilities to end users reduces the need for construction of additional pipeline transportation capacity to meet peak demands, allowing long-distance transportation lines to be designed to accommodate average annual flows, with some excess for responding to demand surges. Off-peak transportation would move gas for baseload demand, storage replenishment, and incremental service to low-priority customers not supplied during peak periods. Local distribution networks in the Northeast already are designed to meet very high demand surges.[9] For example, the 1999 flow capacity of transportation pipelines into New England was only 2.7 Bcf per day, but local gas utilities managed peak deliveries of 3.4 Bcf on January 17, 2000.[10] The incremental sendout during a period of peak demand is usually a combination of storage gas, LNG imports, and propane.

Contracts for Natural Gas Service

A key objective of natural gas system operators is to meet the demand requirements of its core (firm) customers (primarily residential and small commercial customers) on peak days. In general, the larger the proportion of residential and commercial space-heating customers to total customers, the more variable the load profile. For the heating season, the LDC will contract for firm supplies and transportation with pipeline companies to ensure that sufficient supplies will be available for its core customers. Many LDCs are mandated or encouraged by their state public utility commissions (PUCs) to reserve a certain amount of capacity for reliability of service and keep a certain level of stocks on hand that exceeds peak demand.

Because natural gas demand is seasonal and pipeline systems generally are designed to handle expected loads during periods of peak demand, spare capacity usually is available during off-peak periods, even after accounting for gas to replenish storage inventories. The combination of fixed pipeline capacity and variable load has led to the development of interruptible service contracts for some natural gas customers. Under such contracts, a customer agrees to gas service without guaranteed performance in

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[6] A volume of gas (known as base gas or cushion gas) is needed as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates, so that only the working gas capacity proportion of the total storage capacity is available for use.

[7] Days of supply is measured as the ratio of working gas capacity to peak-day deliverability. LNG supplies and normal underground storage should not be combined for this calculation. The addition of LNG distorts the calculation because it has a very high deliverability for only short durations. In practice, flows diminish as underground stocks are depleted, and actual drainage of all working gas from depleted reservoirs would require more time. The maximum deliverability rate is calculated for a full reservoir.

[8] Designated by the state public utility commission to have the responsibility to offer natural gas service to all consumers who request it within a geographic area.

[9] In some areas, gas is delivered directly to consumers by interstate pipeline companies, bypassing the LDCs. This practice is not thought to be widespread in the Northeast.

[10] "New England's Natural Gas Industry Reaches New Growth Levels," New England Gas Association Press Release (March 23, 2000), web site biz.yahoo.com/prnews/000323/ne_gas_ass_1.html.

Table 1. Gas Storage Capacity and Deliverability in the Northeast, 1999

Region/State	Working Gas Capacity (million cubic feet)	Total Capacity (million cubic feet)	Peak-Day Deliverability[a] (million cubic feet per day)	Days of Supply at Full Capacity
Middle Atlantic				
Underground				
New York	84,638	188,474	1,167	72.5
Pennsylvania	397,987	750,007	7,571	52.6
Total	**482,625**	**938,481**	**8,738**	**55.2**
LNG				
New York	3,399	3,399	772	4.4
New Jersey	4,712	4,712	624	7.5
Pennsylvania	4,503	4,503	634	7.1
Total	**12,614**	**12,614**	**2,030**	**6.2**
New England				
Underground	0	0	0	–
LNG				
Connecticut	2,549	2,549	127	20.1
Massachusetts	9,399	9,399	985	9.5
New Hampshire	4	4	5	0.8
Rhode Island	2,469	2,469	261	9.5
Total	**14,421**	**14,421**	1,378	10.5
Northeast				
Underground	482,625	938,481	8,738	57.4
LNG	27,035	27,035	3,408	7.9
Total Northeast	**509,660**	**965,516**	**12,146**	—[b]

LNG = Liquefied natural gas.

[a]Peak-day deliverability at 12,146 million cubic feet per day is available only for about 8 days. For the remainder of the winter, without LNG, peak-day deliverability is 8,738 million cubic feet per day.

[b]LNG totals should not be added to underground storage, because LNG is normally used to satisfy peak demand when underground storage is also being used.

Sources: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Underground Natural Gas Storage Database and LNG Facilities Database, as of November 2000.

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return for discounted rates. Roughly 10 to 15 percent of all primary arrangements for natural gas deliveries by interstate pipeline companies (excluding transportation for other pipelines) in 1997 were on an interruptible basis.[11]

Interruptible service contracts vary in terms and conditions but, generally, allow for service interruptions as a result of either temperature threshold triggers or system operating conditions, such as when line pressure is threatened by high rates of drawdown (see box, "Triggers for Interruption," p. 17). LDCs or pipeline companies may reserve the right to interrupt or curtail service in the event of an emergency, for maintenance of the system, or in order to continue service to their firm service customers. LDCs also interrupt gas service to their nonfirm customers to prevent the use of high-cost equipment or supply options, such as propane injection. In addition, some contracts provide service for only a limited period, such as a month, or on a seasonal basis with suspensions of service scheduled during the winter.[12] Suspension of service is not considered an interruption as long as the terms of the arrangement are met during the period of performance for the contract.

Interstate transporters and LDCs go to great lengths to avoid performance failure under firm service contracts because of the serious implications for their customers and others.[13] The companies also try to continue service even under interruptible contracts, subject to the availability of capacity during peak demand periods and the ability to continue service without resort to high-cost measures. During periods of heavy demand, however, such as during the heating season, interruptions under interruptible contracts are a regular feature of the gas industry as a whole. The movement to regulatory reform at the Federal and state levels has not altered the basic role or impact of interruptible gas contracts.

The Role of Interruptible Natural Gas Service

Interruptible service arrangements provide opportunities for large-volume energy consumers such as industrial customers and electricity generators to obtain energy supplies at lower prices, which enhances the general efficiency of the overall economy. Also, when interruptible customers use the natural gas system, at least some of the resulting revenues are applied to reducing transportation costs for firm customers. If interruptible natural gas customers became firm customers, new capacity might have to be built unless uncommitted capacities were available for firm service. Costs could increase for firm customers using the system because revenues from interruptible service would no longer be available to reduce costs. Also, pipeline operators could be faced with more unused off-peak capacity to auction off, with a very limited base of seasonal users, thereby reducing the value of the interruptible capacity. Pipeline companies currently gain some revenues from the sale of interruptible capacity. There could be a considerable loss of efficiency in the operation of the gas market and the economy in general if customers with switchable capacity were required to consume natural gas year round.

Interruptible service contracts have become part of standard business practices for many large-volume energy users such as power generators. Until recently, electricity generators using natural gas as their primary fuel have been reluctant to commit contractually to firm (365-day) gas service because of the high costs for such service. Electricity generators may opt for alternative fuel use when using interruptible gas service. Some options include building a short-duration storage facility for distillate (or residual) fuel oil or shutting down the generator when gas service is actually interrupted and importing power from an adjacent region. Another alternative might be to contract for a variety of semi-firm services (for up to 365 days) but allow a local gas distribution company the right to call on the gas for a specified number of days. Because many winters have been warm in the past 5 years, interruptible gas service has effectively turned into firm service without the higher costs. Under these circumstances, the incentive for generators to commit to costlier firm service options has been limited.

Natural gas service may also be suspended voluntarily by customers who switch to other fuels or reduce operation,

[11] Interstate Natural Gas Association of America, *Gas Transportation Through 1997*, Report No. 99-01 (April 1999). The stated percentages reflect primary capacity contract arrangements. Through capacity release transactions, at least some of the capacity held by firm contracts is resold on an interruptible basis.

[12] For example, both utilities that serve New Hampshire require all interruptible customers to be offline for a month during the heating season; the LDC must notify customers by September 1 which 30 days of the heating season will be interrupted.

[13] Although quite rare, and not the case in January and February 2000, interruptions may occur under firm service contracts when conditions diminish or jeopardize system capability to the point that deliveries cannot meet all of the supplier's firm contract obligations.

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Triggers for Interruptions

Contracts for interruptible natural gas service specify the particular terms and conditions under which service will be interrupted. Local distribution companies (LDCs) set out these conditions of service in public utility commission (PUC) approved filings referred to as tariffs. Under the majority of interruptible tariffs in the Northeast, LDCs reserve the right to interrupt or curtail service in the event of an emergency, for maintenance of the system, or in order not to compromise service to its firm service customers. Often the contract specifies a temperature threshold that will trigger an automatic curtailment in service. The customer, in most cases, can have the option of having either a manual or automatic shutoff valve or a manual or automatic temperature control to indicate an interruption in service.

In the event of an interruption in service that is not an emergency, the LDC will notify the customer or automatically curtail service within a maximum of 3 working days or in some cases in as little as 2 hours. If the customer only has manual controls, which means that the LDC will not shut off gas service automatically without customer notification, the LDC will try to contact customers to inform them of the interruption. However, if an interruption occurs and the customer does not curtail its use of gas for whatever reason, certain penalties will apply during times of unauthorized use. In addition, if a customer continues its unauthorized gas use for a period over 24 hours, the LDC may apply more severe penalties such as the termination of the interruptible sales or transportation agreement.

In the event of an emergency, which could include a problem in the system or a recently issued operational flow order by a pipeline company serving the system, the LDC may interrupt service with only an hour notice to the customer. It can be difficult to provide notification in such a short period of time, which could result in the use of unauthorized gas by the customer. The LDC usually does not assume any responsibility for the use of unauthorized gas in the event of an emergency, so the customer is solely responsible for being aware and informed of any interruptions or curtailment of service. (In the tariff agreements reviewed for this analysis, a 24-hour period is the normal amount of time unauthorized gas may be used before more serious penalties are imposed, which can include but is not limited to a termination of the contract agreement.)

In contracts that set temperature-specific terms for interruption, LDCs can give a manual or automatic temperature control option as an alternative notification method in the event of an interruption. The customer may have the option either to have service automatically shut off when the temperature reaches a certain degree or the customer may be able to shut off gas service manually when the temperature reaches the specific trigger degree determined by the LDC. In certain contracts, the shut off temperature is specified, while in other contracts the shut off temperature may vary, depending on factors that can include weather, supply, and available capacity. Under the temperature-control option, service is resumed when the outside temperature reaches a certain degree for a sustained period of time determined by the LDC.

even when delivery capacity is available (see box, "Economic Switching," p. 18). For example, some demand shifted from natural gas to distillate fuel oil during January and February 2000 because of the relative fuel prices. The additional demand from customers who voluntarily choose to switch despite the availability of gas service could be significant and would have the same impact on distillate fuel oil markets as equivalent demand owing to interruptions. This aspect of customer demand is examined further in Chapter 4. It is not discussed further here because, although it is arguably related to the availability of interruptible service, it is not a direct consequence of supplier performance under interruptible service contracts.

Backup Fuels Used by Natural Gas Customers

Customers with interruptible service need dual-fuel facilities and equipment to burn an alternative fuel if they plan to continue operating during a natural gas interruption. Some contracts specify that interruptible gas customers keep an "adequate" supply of alternative fuel on hand and maintain the dual-fuel equipment necessary

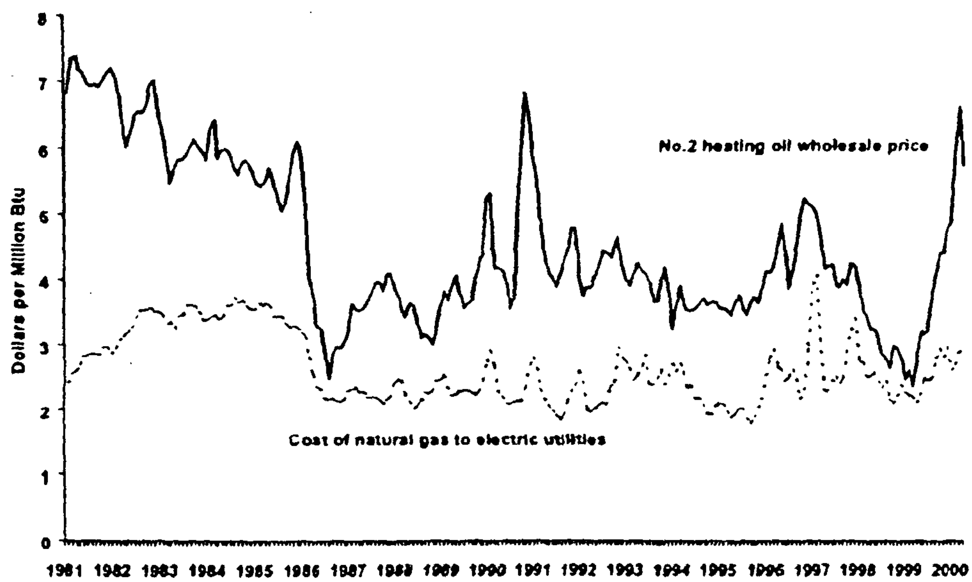
Economic Switching

Dual-fuel equipment, found mostly in large commercial, industrial, and electricity generation applications, can be adjusted to switch between combustion of one fuel to another. While the cost of installing dual-fuel capable equipment is higher than for dedicated equipment, there are paybacks over the life of the equipment. Dual-fuel customers can better manage costs by the appropriate choice of fuels. Another benefit for companies with dual-fuel burning capability is the possibility to contract for a more favorable interruptible tariff for natural gas.

The choice of which energy to consume at a dual-fuel burning facility is frequently driven by price on a dollar per Btu basis, relative efficiency in combustion, availability or security of supply, emissions, and other important considerations. Natural gas/distillate and natural gas/residual are the most common dual-fuel installations. The natural gas/distillate dual-fuel combination is more critical during a winter event owing to the cascading impact on the home heating oil market.

Dual-fuel-capable customers frequently opt to use natural gas for its price competitiveness. In the industrial and electric generation sectors, historically natural gas has been the more economic fuel to consume (see the following chart). In actuality, it is difficult to identify these customers as "natural gas customers" or "distillate customers" because of the switching that takes place. In effect, these customers are simply "energy customers."

U.S. Average Natural Gas and Distillate Prices, January 1981 - March 2000



Note: No. 2 distillate heating oil wholesale prices and the cost of natural gas to electric utilities are representative of energy costs to dual-fuel capable facilities.
Source: Energy Information Administration, Short-Term Energy Outlook Query System., November 14, 2000.

Economic Switching (Continued)

Economic switching occurs when dual-fuel facilities switch fuels to consume a more price-advantageous fuel. Price differentials between distillate and natural gas theoretically could widen to the point that all dual-fuel facilities would migrate to the alternative fuel.

During a winter event, dual-fuel facilities have the capacity to alleviate demand pressures by responding to price signals and switching to another fuel. Economic switching is in contrast to the switching that is forced on dual-fuel-capable customers when natural gas companies invoke contractually-allowed service interruptions to maintain supplies for firm service customers.

Irrespective of the cause, the upper limit of the switching that can occur is the total capacity of dual-fuel facilities. In the Northeast, the maximum demand that can be placed on distillate by dual-fuel customers who either switched to distillate for price considerations or were interrupted is around 133 thousand barrels per day (see table below). It is possible that distillate suppliers would not have to absorb a full 133 thousand barrels per day from dual-fuel customers since complete switching by all dual-fuel customers is unlikely. Given an option, many facilities choose not to switch, if at all possible, because of the transitory nature of the price differential, environmental regulations, convenience, or other reasons. In addition, dual-fuel facilities have two other courses of action that would not further tighten energy supplies: drawing from customer-owned energy stockpiles and scaling down or suspending operations.

Estimated Distillate Fuel Oil Switching in the Northeast by Sector
(Thousand Barrels per Day)

Sector	Daily Average Switchable Volumes in December–February
Commercial	86
Industrial	16
Electric Generation [1]	31[2]
Total	133

[1]Because usually only one-third of distillate consumption for electricity generation occurs in the winter months (December, January, and February), the consumption shown is the estimated winter use portion, assuming that 40 percent of the year's distillate use might occur in the winter of an unusual year.

[2]Winter only.

Source: Adapted from Energy Information Administration, *The Northeast Heating Fuel Market: Assessment and Options*, SR/OIAF/2000-03 (Washington, DC, May 2000), Table ES-1.

to utilize the fuel. However, of the states in the Northeast, only New York and New Jersey have statewide regulations regarding adequate supply and these are relatively new requirements. In mid-August 2000, the New York State Public Service Commission ordered that interruptible contract holders have a 7-to-10-day supply of backup fuel in storage at the start of the 2000-01 heating season.[14] In September 2000, the New Jersey Board of Public Utilities ruled that all interruptible gas customers using distillate fuel oil as an alternative fuel have a 7-day supply on hand by November 1, or equivalent firm supply arrangements if onsite storage capacity is less than 7 days.[15] In Massachusetts, a generic clause that required interruptible contract holders to have a sufficient supply of backup fuel was deleted from the tariff in 1993, because customers wanted to have the right to shut down if they chose instead of fuel switching or paying a higher firm service price.

The two most common alternative fuels for interruptible natural gas customers in the Northeast are No. 2 distillate fuel oil and No. 6 residual fuel oil, although No. 4 distillate oil, kerosene, and propane are also used.

- **No. 2 distillate oil** is most commonly used as an alternative fuel in the commercial and the light industrial sector, for example, schools, apartment buildings, and offices. It is used to heat residential and commercial buildings and to fire industrial and electric utility boilers. The residential plus commercial sectors accounted for more than 90 percent of total distillate fuel oil consumption in the region. Industrial firms and power plants accounted for smaller shares, 8 percent and 2 percent, respectively, on an annual basis. However, while small on an annual basis, the role played by industrial users and power plants can vary significantly during the course of a year.

- **No. 6 residual fuel oil**, which is what remains after lighter petroleum products have been removed in the refining process, is used for the production of electric power, space heating, and various industrial purposes. Even though it requires preheating equipment, it is the most economical oil alternative, which accounts for its widespread use by large-volume industrial and electric utility users in the Northeast. Its high sulfur content, however, makes it the least favorable alternative fuel oil from an environmental standpoint.

- **No. 4 distillate oil**, which is a mixture of distillate and residual fuel oils, is much less commonly used as an alternative fuel by the commercial and industrial sectors in the Northeast than either No. 2 distillate or No. 6 residual oil. Most industrial consumers use No. 4 as an alternative to residual oil. Unlike No. 6 residual fuel oil, No. 4 fuel oil does not require the use of preheating equipment, but it is not as economical to burn in large volumes as residual oil. In addition, No. 4 oil has a higher sulfur content than No. 2 distillate, so small-volume users from the commercial sector prefer No. 2 distillate as a cleaner alternative. The supply of No. 4 fuel oil is smaller than that of No. 2 distillate or No. 6 residual, in correspondence to its demand in the market.

- **Kerosene** is used for residential and commercial space heating, and is used as a blending agent to keep heating oil and diesel fuel from thickening during cold weather. It falls within the light distillate range of refinery output that mainly includes diesel fuel and jet fuel oils.

- **Propane**, a gas, is used as a fuel in the residential, commercial, and industrial sectors, and is important as a petrochemical feedstock. It is also used by natural gas suppliers for peak shaving, wherein a propane-air mix of about 55 percent propane and 45 percent air is injected into the natural gas system as a partial replacement for up to one half of the natural gas. This propane-air mix has burning characteristics similar to natural gas, with about 35 percent higher Btu value.

The additional demand on petroleum markets as a result of gas service interruptions particularly affects the regional home heating market. More than half of the households in New England and nearly a third in the Middle Atlantic States heat with distillate fuel oil. Nationwide, distillate fuel oil accounted for only 8

[14] New York utilities are required to implement a special information plan to ensure that all interruptible customers are prepared to leave the gas system during periods of peak demand and that they have other options available. "NY PSC Approves Measures to Help Ensure Reliability of Supplies for Natural Gas Customers in the Coming Winter," New York State Public Service Commission Press Release, Docket 00066/00G0996 (August 16, 2000), web site: http://www.dps.state.ny.us.

[15] The New Jersey rules (Docket No. GO00020088, 9-20-00) apply only to interruptible customers using No. 2 fuel oil, No. 4 fuel oil, jet fuel, or kerosene as alternative supply. Wholesale electric generators, including cogeneration customers with wholesale electric contracts, are exempt. The stated intent of the order is to ensure that interruptible customers comply with system interruption notices so that all firm customers will receive reliable service. Large penalties will be charged to any customers who ignore notices of interruption. See the New Jersey Board of Public Utilities web site at http://www.bpu.state.nj.us/.

percent of the energy delivered to the residential sector in 1997, but 73 percent of that consumption occurred in the Northeast. Even with the occasional surge in heating oil prices, heating with distillate fuel oil in the Northeast on average has been less expensive historically than heating with natural gas.

Although generally small in comparison with residential use, distillate fuel oil use in other sectors in the Northeast can have a significant impact on prices, especially when demand is strong and supplies are tight. As in the residential sector, distillate fuel oil use in the commercial sector has declined over the past 20 years. In the commercial sector, distillate fuel oil consumption declined from 18 percent of total commercial energy use in the Northeast in 1980 to 12 percent in 1997.

The consumption of distillate fuel oil in the industrial sector in the Northeast is divided nearly equally between manufacturing and nonmanufacturing uses. In nonmanufacturing industrial uses, where distillate fuel oil is used primarily for onsite transportation, it is unlikely that a significant portion of it could be switched easily to another fuel. Within the manufacturing segment in the Northeast the key uses of distillate are as a boiler fuel (37 percent), as a process fuel (32 percent), for heating and ventilation (12 percent), and for onsite transportation (10 percent).

The vast majority of the fuel oil used for electricity generation is residual fuel oil. Distillate fuel oil is limited in applications because of its relatively high price. Typically, it is used in small amounts in steam plants for flame control and in relatively inefficient combustion turbines and internal combustion engines when the demand for electricity is high and other fuels are unavailable.

Summary

Interruptible service contracts are a regular feature of the natural gas market in the Northeast. They allow large-volume energy consumers with fuel switching or dual-fired fuel capability to purchase natural gas at lower rates than those charged for firm service. At the same time, they allow local distribution companies and pipeline operators to increase utilization of their fixed assets and better manage costs of service on average. Sales of off-peak interruptible capacity generate revenues that contribute toward at least a portion of the system's capital costs, potentially providing benefits to firm service customers as well. Higher utilization overall enhances the economic return on pipeline and distribution assets.

3. Natural Gas and Distillate Market Dynamics During Severe Winter Events

In recent years, distillate fuel oil markets in the Northeast have experienced several price spikes during the winter. In these cases, distillate prices suddenly surged above crude oil prices, remaining volatile and elevated for several weeks. Each incident tended to include a combination, but not necessarily all, of the following factors: weather (severe cold temperatures), increased demand for all fuels, fuel oil supply disruptions because of refinery outages or delivery problems, interruptions of gas service, and relatively low stocks of fuel oil and/or natural gas. Despite the many similarities among the incidents, there were differences as well. The relevance of these factors during previous winters can be considered by comparing the events of four selected periods of cold temperatures and distillate and/or natural gas price spikes in the Northeast: December 1989 to January 1990, January to February 1994, February 1996, and January to February 2000.

This chapter examines the dynamics of natural gas and distillate fuel oil markets during these four periods of unusually high gas or heating oil prices in recent years and enumerates the most likely factors that affected heating oil demand and supply and thus contribute to spikes in natural gas and/or heating oil prices. It does not attempt to quantify the relative contribution of each factor to the overall increase in fuel prices, but it does provide a framework for understanding the role of gas service interruptions and their possible impact on distillate fuel markets.

December 1989 to January 1990

The coldest weather in the United States in 102 years hit in December 1989, disrupting supplies of natural gas and petroleum products. By the weekend of December 23, the cold weather that had been affecting the Mid-continent and Northeast extended to the Gulf Coast. The cold front froze water pipes and damaged valves and instruments, and many oil refineries were either partially or completely shut down, leading to disruptions in petroleum supplies. Frozen equipment also caused curtailments of natural gas production, which likely led to more fuel switching than might otherwise have been the case.

Natural gas stocks in underground storage on November 1, 1989, were 3,268 billion cubic feet (Bcf) compared with the average 3,187 Bcf in reserve on November 1 during the previous 5 years.[1] Natural gas consumption in December rose in response to the cold weather, with deliveries to the residential and commercial sectors in the Northeast up 29 and 25 percent, respectively, compared with the previous year. Deliveries were only 1 percent higher to the industrial sector than year-earlier levels but 67 percent higher to the electric generation sector. The tightness in supplies was reflected in gas prices to the industrial and electric sectors, which increased from $4.33 and $3.74 per million Btu (MMBtu) to $4.97 and $4.65 per MMBtu, respectively, between November and December.[2]

Although the cold snap initially affected petroleum processing, by the second and third weeks of December refiners were able to respond to the demand surge by increasing distillate production to the highest level seen at any point during the 3 years before 1989. In response to the high prices, imports also increased, but with a lag in time. Before these volumes could be delivered, the Northeast remained dependent on its modest stocks. U.S. distillate stocks at the primary (refinery, pipeline, and bulk terminal) level were more than 14 million barrels (almost 12 percent) below average when the 1989-90 winter heating season began, and half this shortfall was on the East Coast. Stocks at electric utilities (tertiary or consumer level) were plentiful, though, and could have covered the sector's entire consumption of distillate during this time period.[3] The timing of the event, early in the heating season, may have forced utilities into the market to save stocks for later in the season.

The tight market conditions for distillate supplies affected the price differential between distillate and crude oil. During the peak of the winter 1989-1990 event, crude oil

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[1] Natural gas data contained in this section are drawn from Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (Washington, DC), various issues.

[2] Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (Washington, DC), various issues. Spot natural gas prices, which are more representative of the prices paid by large consumers, were not available during this period owing to the newness of the spot natural gas market.

[3] Energy Information Administration, *Effects of Interruptible Natural Gas Service: Winter 1989-1990*, SR/OG-91-01 (Washington, DC, June 1991), pp. 9 and 17.

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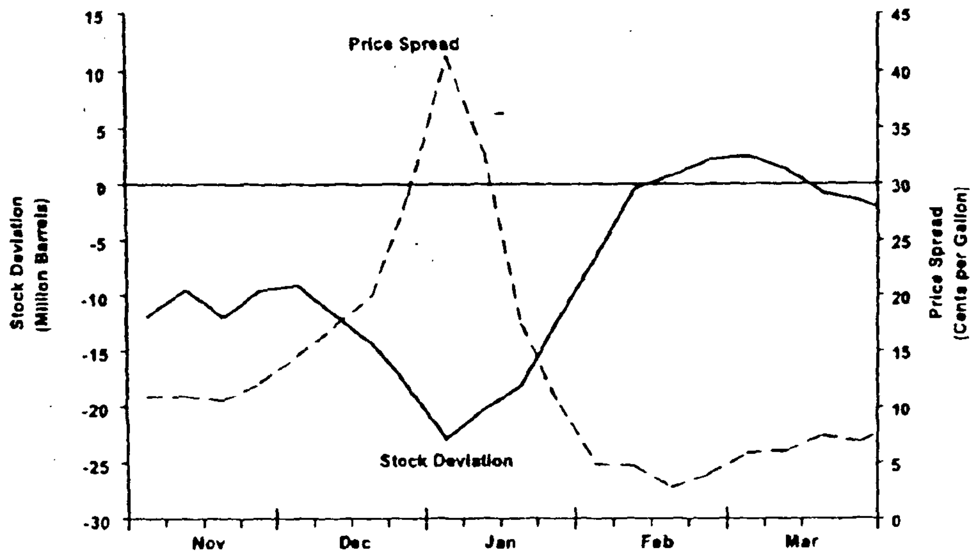
DOE006-0028

Figure 8. Winter 1989-90: East Coast Distillate Stock Variations from Average and the Spread Between Distillate and Crude Oil Prices



Note: Price spread is the weekly average New York Harbor No. 2 heating oil price minus the West Texas Intermediate crude oil price. Stock deviation is the week-ending stock level minus the average week-ending level for the given week, calculated from 1989 through 1999.

Sources: **Spot Prices**: DRI Platt's Daily prices averaged over a week. **Week-Ending Distillate Stocks, January 1990. Forward**: Energy Information Administration, *Weekly Petroleum Status Report*, Table 10. **Week-Ending Distillate Stocks, November and December 1989**: American Petroleum Institute.

was $21.70 per barrel ($27.65 in 2000 dollars) compared with the 2000 event which had an underlying crude oil price of $28.06 per barrel. With primary stocks well below normal, distillate price spreads[4] at the beginning of December were 15 cents per gallon and growing (Figure 8). The New York Harbor price for home heating oil was 61.4 cents per gallon at the beginning of the month and 92.9 cents per gallon by the end of the month. The price spiked at the end of the month when the distillate spread peaked at more than 41 cents.

Despite the high underlying cost of crude oil and the wide spreads between distillate and crude oil prices that developed as a result of the cold weather, distillate had about a $0.50 per MMBtu price advantage over natural gas in the industrial and electric generation sectors. At the time, just more than 128 thousand barrels per day of estimated switchable capacity was in place[5] that could have been used by interrupted gas customers or customers switching to distillate to take advantage of a possible price advantage. This distillate price spike seems to have been motivated by a combination of causes, including the weather (severe cold temperatures), increased demand for all fuels, fuel oil supply disruptions because of refinery outages, suspension of gas service to interruptible customers, and relatively low stocks of fuel oil. The events and conditions surrounding natural gas and distillate fuel oil markets at the time, particularly those pertaining to natural gas interruptions, were analyzed in detail in the Energy Information Administration (EIA) report *Effects of Interruptible*

[4]No. 2 heating oil in the New York Harbor minus West Texas Intermediate.

[5]Estimate based on the methodology used in the Energy Information Administration report, *The Northeast Heating Fuel Market: Assessment and Options*, SR/OIAF/2000-03 (Washington, DC, May 2000), Table ES-1, using data from: -EIA, *Commercial Building Energy Characteristics 1992*, DOE/EIA-0625(92), p. 28, and -EIA, *Effects of Interruptible Natural Gas Service: Winter 1989-1990*, SR/OG-91-01, p. 13.

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Natural Gas Service: Winter 1989-1990. The analysis shows that weather was the major driving force behind the distillate price increase (see box below, "An Analysis of Distillate Prices in the Winter of 1989-1990").

An Analysis of Distillate Prices in the Winter of 1989-1990

Episodes of sudden price spikes in heating oil markets are not uncommon, with a number of occurrences since the winter of 1989-1990. Most of these events have not been examined rigorously to assess the contributing factors behind the price spikes, but one exception is the event in the 1989-1990 winter. In a report *An Analysis of Heating Fuel Market Behavior 1989-90*, the Energy Information Administration (EIA) estimated the amount of incremental distillate demand by electric utilities and analyzed a set of factors behind the price surge and estimated the relative contribution of each to the overall price rise. Much of the 1989 to 1990 information in this section is drawn from that report.

Additional distillate fuel oil consumption in December 1989 because of cold weather was estimated to be 40.3 thousand barrels per day, including the 13.2 thousand barrels per day from the curtailment of natural gas service provided to electric utility customers. The remaining 27.1 thousand barrels per day was credited to a number of different factors, the most important being the increase in demand from existing residential, commercial, and electric utility customers, and from industrial customers who switched from natural gas.

An econometric model was created to explain distillate price increases, including weather, crude oil prices, and primary distillate stock levels as explanatory factors. According to the analysis, all these factors had a statistically significant contribution to the increase in distillate prices. Distillate purchases by electric utilities accounted for 34 percent of the December 1989 spike in the distillate price in the Central Atlantic Region, with roughly half of this effect being attributable to those purchases necessitated by interruptions of natural gas service (Table 2).

Of an almost 20-cent-per-gallon change in the residential price for distillate, 3.48 cents came from gas interruptions to the electric utility sector, while the remainder was identified as being driven by weather, increased electric utility purchases not caused by interruptions, increased crude oil prices, and inventory levels. Twenty-one percent of the price increase, 4.12 cents, was attributable to other factors that could have included voluntary switching and gas service interruptions to industrial customers, but a reliable division of this increment is not possible based on the reported results. Thus, the incremental distillate demand from gas customers played a significant role in the price rise to residential customers in the Central Atlantic region during December 1989. The factors contributing to the price rise in 2000 and their relative importance may not have been the same as in 1989 as markets have changed since that time and specific variables were a different size.

Table 2. Contribution of Selected Variables to the December 1989 Distillate Fuel Oil Price Spike in the Central Atlantic Region

Factor	Contribution (cents per gallon)	Percentage Contribution
Weather	6.86	35
Total Impact of Electric Utility Purchases of Distillate	6.73	34
Electric Utility Purchases of Distillate Attributable to Natural Gas Interruptions	3.48	18
Electric Utility Purchases of Distillate Not Attributable to Natural Gas Interruptions	3.25	17
Crude Oil Prices	1.64	8
Primary Distillate Inventories	0.25	1
Portion of the Price Change Explained by Other Factors	4.12	21
Total Change in Residential Price from Nov to Dec 1989	19.60	100

Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, *Effects of Interruptible Natural Gas Service: Winter 1989-1990*, SR/OG-91-01 (Washington, DC, June 1991), Table ES-1.

January to February 1994

January 1994 was 15 percent colder than normal in the Northeast, and for one week during the month temperatures were 40 percent below normal.[6] Unlike in December 1989, the cold weather did not extend to the Gulf Coast, and deliveries of natural gas and petroleum products to the Northeast were not disrupted.

At the start of the 1993-94 heating season, underground natural gas stocks in the Northeast were 20 Bcf (5 percent) lower than the 1990-through-1999 average for the month (Figure 9). By New Year's Day 1994, 332 Bcf was in underground storage in the Northeast compared with a 344 Bcf average. After the weather turned, the spot price for natural gas at the New York citygate[7] increased from $2.58 per MMBtu on January 18, 1994, then spiked to $7.50 before settling at $4.70 per MMBtu 2 weeks later and persisting at that level for another 2 weeks (Figure 10). Almost 20 percent more natural gas was consumed in January 1994 than in January 1993, despite the fact that deliveries to the electric generation sector were less than half the amount sold in January 1993. By the end of February 1994, stocks were 46 Bcf below the 10-year average.

Distillate stocks on the East Coast began the winter of 1993-94 at above average levels and stayed about 7 million barrels above through the beginning of January (Figure 11). During the first 5 weeks of 1994, East Coast stocks declined by 31 million barrels. Distillate/crude oil spreads during January rose by 5 cents per gallon to reach 15 cents per gallon. By the last week of the East Coast stock decline (ending February 4, 1994), distillate stocks were 12 million barrels below average, and distillate spreads peaked shortly thereafter at 25 cents per gallon. The spot price for home heating oil in the New York Harbor increased from 47 to 60 cents per gallon. Throughout the period, crude oil prices remained relatively low. In the peak distillate price week in 1994, the crude oil price averaged less than $15 per barrel (35 cents per gallon), compared with prices of near $30 per barrel in early 2000.

Estimates of voluntary fuel-switching from natural gas or interruptions of natural gas service attributable to the 1994 cold front were never made, although the decline in temperatures may have triggered a few unusual gas service interruptions. With respect to fuel switching, distillate enjoyed at most only a $0.20-per-MMBtu cost advantage at any time—a weaker inducement to switch than was the case in 1989-1990.

The distillate price spike in 1994 seems to have been motivated by a different combination of factors than in 1989-1990. Once again, the weather was a key influence as it increased demand for all fuels, but it did not cause disruptions of fuel oil or natural gas supplies this time. Another factor that contributed to the price surge was the relatively low level of distillate stocks.

February 1996

Temperatures on the East Coast were consistently at or somewhat below normal levels from the beginning of the 1995-96 heating season through most of January. By the last week in January, a front moved into the Northeast and temperatures dropped almost 30 degrees. The cold front did not move into natural gas production areas and affect flow from this source. The cold weather event of 1996 was notable for the comparatively late start of the cold weather and the lack of a spike in distillate prices in both the Northeast and Midwest, despite higher natural gas prices and relatively cold temperatures in both regions.

Before the onset of the heating season, underground natural gas stocks in the Northeast were about 2 percent above the 1990-through-1999 average of 421 Bcf. After a short cold wave in early January, stocks were left at 79 percent of the 1990-through-1999 average for the month. The first day of February heralded a cold front that ultimately caused stocks to be drawn almost 7 percent faster than the average. Natural gas consumption in the Northeast was about equal to consumption in the previous year, despite a 60-percent decline in consumption for electric generation.[8]

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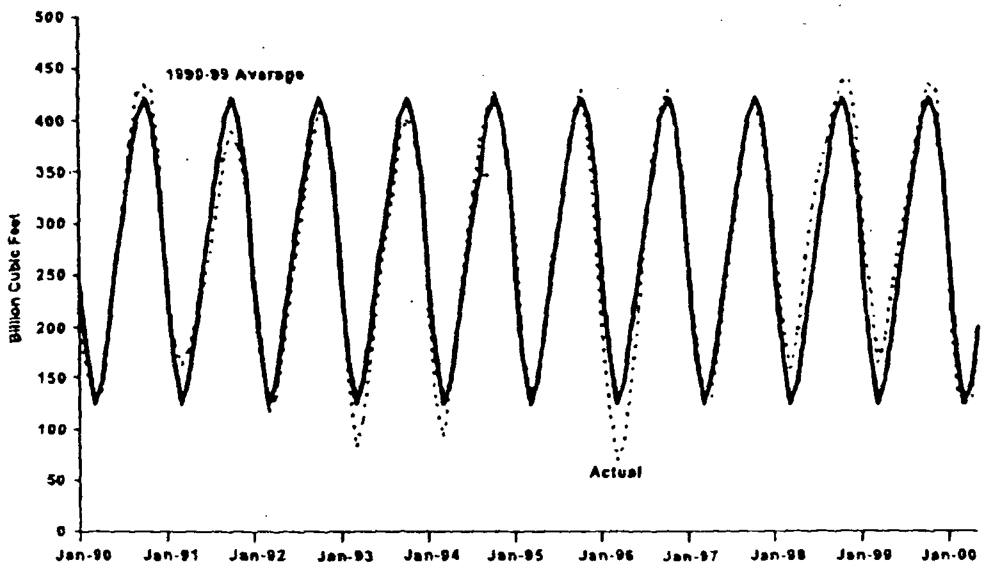
[6] Petroleum Industry Research Foundation, "Oil Markets During the Cold Weather: The Buck Stops Here," Memorandum Submitted to the *Subcommittee on Energy and Power of the Energy and Commerce Committee*, U.S. House of Representatives (February 18, 1994).

[7] The prices for gas traded at Transco Zone 6 are used as indicators of spot prices for the New York citygate. See *Gas Daily* (Arlington, VA: Financial Times). Transco No. 6 spot price for natural gas is a reasonable surrogate for the wholesale prices that large commercial, industrial, and electric generation customers pay for energy.

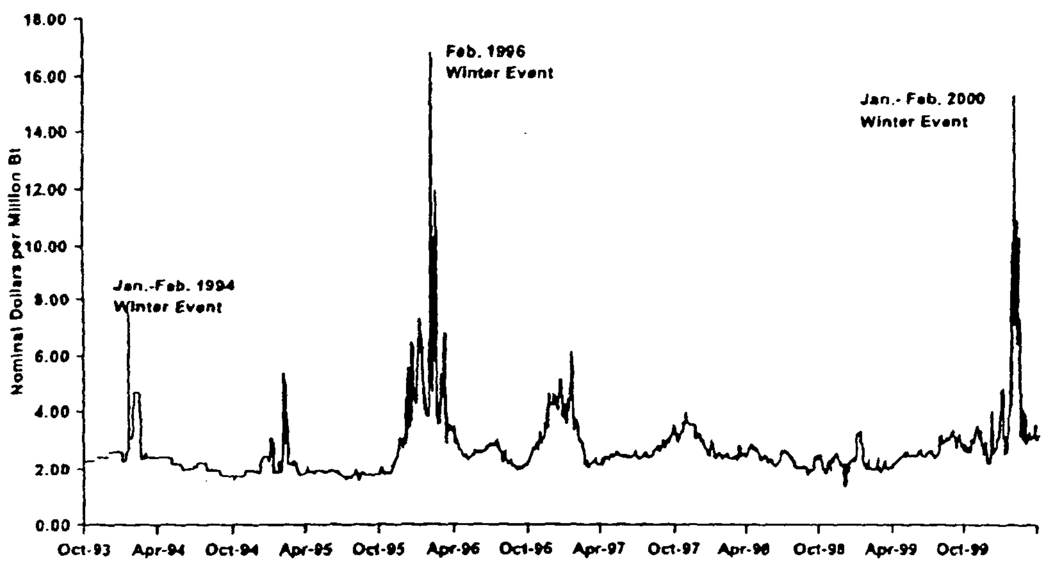
[8] Energy Information Administration *Natural Gas Monthly*, DOE/EIA-0130 (Washington, DC), various issues.

Figure 9. Working Gas in Underground Storage in the Northeast, January 1990 – March 2000



Source: Energy Information Administration, *Natural Gas Monthly* (various issues), Table 14.

Figure 10. Spot Price of Natural Gas at the New York Citygate, October 1993 - March 2000



Source: Financial Times Energy, *Gas Daily* (various issues). The price for gas traded at Transco Zone 6 is used as indicator of spot prices for the New York citygate.

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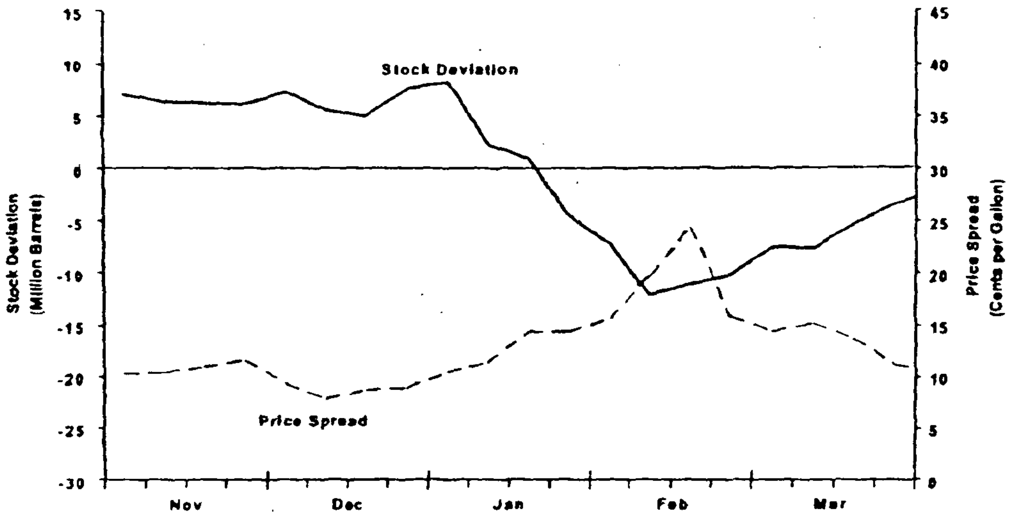
Figure 11. Winter 1993-94: East Coast Distillate Stock Variations from Average and the Spread Between Distillate and Crude Oil Prices



Note: Price spread is the weekly average New York Harbor No. 2 heating oil price minus the West Texas Intermediate crude oil price. Stock deviation is the week-ending stock level minus the average week-ending level for the given week, calculated from 1989 through 1999.

Sources: **Spot Prices:** DRI Platt's Daily prices averaged over a week. **Week-Ending Distillate Stocks, January 1990, Forward:** Energy Information Administration, *Weekly Petroleum Status Report*, Table 10. **Week-Ending Distillate Stocks, November and December 1989:** American Petroleum Institute.

Toward the end of January 1996, the spot price for natural gas at the New York citygate was $4.50 per MMBtu (Figure 12). On February 2, the New York spot price was $15.50 per MMBtu and went as high as $16.75 on February 5. The spot price stayed ahead of January prices most days through February 20. For the better part of 3 weeks, the spot price of natural gas exceeded oil by at least $0.70 per MMBtu, and was over $11 per MMBtu for two days during the period. The spot price for heating oil in New York climbed by less than 30 percent.

The Midwest also suffered from the same cold front that swept through the Northeast. Spot natural gas prices in the Midwest spiked even more severely than in the Northeast. During the last week of January through the first week in February, the Chicago spot natural gas price topped out at more than $30 per MMBtu, while the spot price of distillate rose to the equivalent of just over $4 per MMBtu (Figure 12).

The extremely high prices for natural gas in both the Northeast and Midwest likely reflect gas service interruptions and may have led to voluntary fuel-switching from gas. Distillate fuel oil enjoyed a significant price advantage over natural gas, and dual-fired energy customers would have shifted to the less costly fuel wherever possible. Natural gas service interruptions were not estimated for this period, but temperatures were cold enough to have invoked clauses for natural gas interruptions. Also, the extremely high gas commodity prices would have precluded continuation of interruptible service in cases where it required the use of such high-cost gas supplies.

For the week ending February 16, 1996, distillate stocks were 10.7 million barrels below the 10-year average. The absence of a sustained runup in distillate fuel prices during this period is noteworthy because temperatures were cold and distillate inventories were quite low—conditions that were present at the time of each of the other distillate price spikes. Based on this example, an absolute causal relation between this set of factors and distillate fuel oil price spikes does not exist. Furthermore, this example introduces the possibility that the timing of the event is a contributing factor in the extent of distillate price spikes. A cold snap later in the heating season allowed a draw on stocks without significantly affecting distillate prices.

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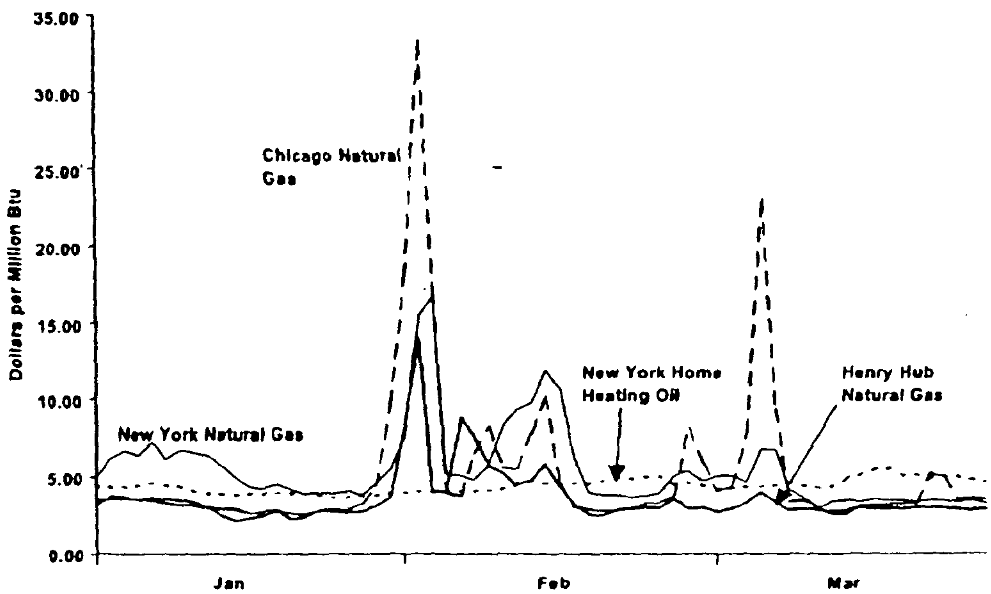
Figure 12. Winter 1996 Spot Prices



Source: Natural Gas Prices: Financial Times Energy, *Gas Daily*, (various issues); New York Home Heating Oil: Reuters News Service. No. 2 Heating Oil, New York Harbor converted to million Btu using 5.825 million Btu per barrel.

January to February 2000

Northeast weather in January and February 2000 was warmer than normal. The regional data on a monthly basis, however, obscure significant variation during some weeks in the period. During the week of January 22, 2000, temperatures in the Northeast shifted from being up to 17 percent warmer than normal to as much as 24 percent colder than normal. This increased weekly heating requirements by an estimated 40 percent. The cold pattern persisted for 3 weeks.

At the end of December 1999, natural gas stocks in the Northeast were 4 Bcf above the 1990-1999 monthly average of 344 Bcf. As temperatures plummeted, natural gas companies withdrew more from storage than ever before.[9] Natural gas deliveries to the Northeast increased by almost percent over year-earlier levels even after accounting for a 20-percent drop in gas consumption for power generation.[10] Tight regional natural gas supplies caused the spot price at the New York citygate to move from $6.34 per MMBtu on January 18 to $15.34 per MMBtu on January 20. Gas prices never dipped below $6.41 per MMBtu during the next 3 weeks.

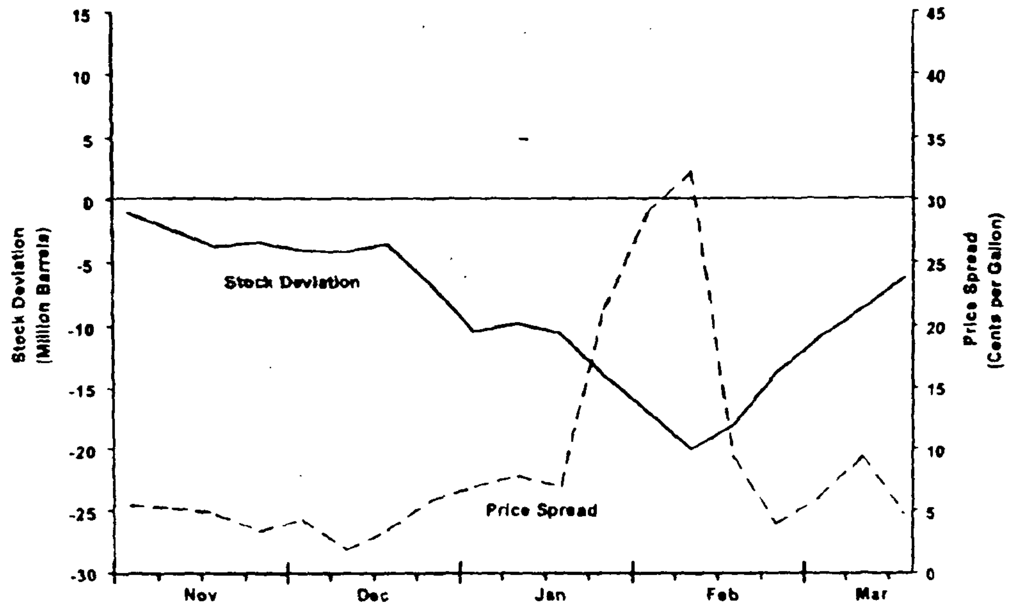
As the heating season of 1999-2000 began, distillate stocks at the primary level were about average (Figure 13). From December 17, 1999, to January 14, 2000, stocks fell by 12 million barrels, ending at a level that was 10 million barrels below average. At the time, Y2K precautionary stocking at the consumer level was suggested as a possible cause for the sharp decline in stocks prior to the onset of cold weather.[11] Distillate/crude oil spreads were well below seasonal averages in December, and they rose only modestly in early January, still remaining below average.

[9] Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (Washington, DC), various issues. Net withdrawals from storage during January 2000 were an all-time high for any month. February 2000 withdrawals were a record for the month of February.

[10] Because of a lack of respondents, does not include Massachusetts, New Jersey, and New York. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (Washington, DC), various issues.

[11] In conducting a survey on January and February 2000 natural gas interruptions, EIA found some evidence that supported a build of Y2K precautionary stocks.

Figure 13. Winter 1999-2000: East Coast Distillate Stock Variations from Average and Spread Between Distillate and Crude Oil Prices



Note: Price spread is the weekly average New York Harbor No. 2 heating oil price minus the West Texas Intermediate crude oil price. Stock deviation is the week-ending stock level minus the average week-ending level for the given week, calculated from 1989 through 1999.

Sources: Spot Prices: DRI Platt's Daily prices averaged over a week. Week-Ending Distillate Stocks, January 1990. Forward: Energy Information Administration, *Weekly Petroleum Status Report*, Table 10. Week-Ending Distillate Stocks, November and December 1989: American Petroleum Institute.

This changed in the latter half of January, as the average weekly distillate spread during the third week increased by 14 cents per gallon over the level of the previous week as the region waited for new supply to relieve the market stress.

The patterns in the distillate spreads were reflected in product prices. New York Harbor spot heating oil prices soared from about 76 cents per gallon on January 14, to a peak of $1.77 on February 4. Between January 17 and February 7, New England residential heating oil prices rose by 66 percent, from $1.18 to $1.97 per gallon.

The distillate price spike in January-February 2000 seems to have been motivated by a combination of factors similar to those in previous events. The weather was severely cold, which increased demand for all fuels. Fuel oil supply disruptions occurred as some refineries experienced production problems and the chain of replacement supplies was disturbed when ice-blocked harbors prevented barges from delivering distillate. At the same time, the diminished stocks of distillate in the region were inadequate to compensate for these supply difficulties.

Although reliable estimates of interruptions to interruptible gas customers were unavailable, a number of speakers at meetings held by Secretary of Energy Richardson in February identified gas service interruptions as an important contributing factor. At the time, analysts estimated that the substitution of gas with distillate fuel oil caused over 100 thousand barrels per day of incremental demand during the second half of January to early

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February.[12] Results of EIA's efforts to assess the volumetric impact on distillate markets owing to gas service interruptions during January through February 2000 are contained in Chapter 4 of this report.

Summary

The specific influences driving distillate prices in severe winter events vary but some have been recurring. Low distillate stocks along with low temperatures contributed to higher distillate fuel oil prices in the Northeast in 1989, 1994, and 2000, with 1996 serving as an exception. Generally, when East Coast distillate stocks fell to 10 million barrels below average, a price spike followed. In the most severe incidents, 1989-1990 and 1999-2000, stocks ultimately fell to 20 million barrels below average.[13]

Even though a connection between distillate prices and incremental demand from fuel-switching energy customers may be present on the East Coast, the relationship, if there is one, appears to be weaker in the Midwest. The greater reliance on nearby refinery supplies in the Midwest seemed to prevent an acute disruption in distillate fuel oil prices in 1996. In addition, timing of the winter event can also dampen price spikes. Unusual weather occurring later in the heating season perhaps allows customers to drawdown stocks with little concern for later needs, thereby taking the pressure off prompt supplies. In 1996, cold temperatures late in the winter in the Northeast caused East Coast distillate stocks to fall to 10 million barrels below average and yet distillate spot prices were unaffected.

Natural gas interruptions are a contributing factor to the increase in demand as shown in 1989 and suggested for other years. The next chapter explores the magnitude of incremental distillate volumes attributable to interruptible gas service contracts.

[12] Petroleum Industry Research Foundation, "What Happened to Heating Oil?" (New York, New York, March 2000), p. 6.

[13] This analytical observation is drawn from Appendix C of the Energy Information Administration report, *The Northeast Heating Fuel Market: Assessment and Options*, SR/OIAF/2000-03 (Washington, DC, May 2000).

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DOE006-0036

4. Interruptions in Natural Gas Service in January and February 2000

Assessing the impact that interrupted natural gas customers may have had on the market for distillate fuel oil requires an understanding of the relationship between the oil and gas markets. Both fuels are used for heating and can be used almost interchangeably in many industrial applications by dual-fuel customers who have the proper equipment. The disruption in the supply of natural gas last winter to some customers holding interruptible service contracts turned some of these customers to their backup fuels. This would have increased the demand for distillate and placed upward pressure on distillate prices. The actual effect on price would depend upon the responsiveness of buyers and sellers to changes in price and the magnitude of the additional demand for distillate.

In order to determine the extent of gas service interruptions in January and February 2000 and the resulting actions of affected customers, the Energy Information Administration (EIA) surveyed major gas suppliers in the Northeast and a sample of end users who receive gas under interruptible service contracts.[1]

- **Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000,"** was sent to 34 natural gas companies who accounted for nearly all the volumes delivered to interruptible end users in the Northeast in 1998. Respondents provided information on volumes of gas associated with interruptible and firm service, the volume and timing of interruptions, and the names and backup fuels of interrupted customers.[2]

- **Form EIA-904, "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000,"** was sent to 101 end users in New England who receive natural gas under interruptible service. A total of 97 respondents provided information on the volumes of gas delivered, the volumes interrupted, and the days interrupted. They also provided data on backup fuel use, including volumes purchased and consumed, inventory levels, and storage capacity.

This chapter examines the data collected from these surveys to determine the extent of gas service interruptions last winter, whom they affected, and their timing. It also compares customer reactions to gas service suspensions based on customer type and type of backup fuel used. For purposes of the analysis, customers were divided into large-volume and small-volume users. In a separate analysis effort, customers were grouped into nine categories according to business sector. The larger entities included power producers who had very different reactions to service interruptions than the smaller customers. The analysis also compares the responses furnished by gas distributors with the responses provided by the interrupted customers in the two surveys.

Overall, an estimated 805 trillion Btu of natural gas was delivered to the Northeast during January and February 2000.[3] Of this amount, 719 trillion Btu was provided under firm contracts and 86 trillion Btu under interruptible contracts.[4] Despite the severe weather in the region during that time, no firm service customers experienced service interruptions. Reported interruptions in service to interruptible gas customers resulted in the nondelivery of an estimated 12.4 trillion Btu of natural gas, or 13 percent of the total volumes that could have been delivered under interruptible arrangements, according to estimates derived from the survey of local distribution companies (LDCs) and pipeline companies.[5]

Although the interruptions in gas service likely were greater relative to previous years' mild winters, the EIA-903 survey data indicate that the interruptions in January and February 2000 represented a relatively small portion of the gas suppliers' planned level of service for

[1] See Appendix B for details on the data collection methodology and Appendix C for copies of the survey forms.

[2] In general, an "interruption" is said to have occurred when an interruptible gas customer experiences an unexpected and involuntary suspension in service. In responding to Form EIA-903, however, service providers gave estimates of interruptions that included some suspensions or cutbacks in service initiated by the customer. Although not interruptions per se, these reductions in gas consumption did result in increased use of backup fuels.

[3] Energy Information Administration *Natural Gas Monthly*, DOE/EIA-0130 (Washington, DC), various issues.

[4] Interruptible deliveries are derived from Form EIA-903 data. Firm deliveries are derived as the difference between total deliveries and interruptible deliveries.

[5] Estimates of the amount of gas that could have been delivered are based on maximum daily quantities, contract amounts, or planning levels as provided by LDCs and pipeline companies about their service arrangements.

interruptible customers. Moreover, the additional demand in the distillate market from interrupted natural gas customers may not have been as large in terms of the volume of distillate fuel oil purchased as previously thought.

Nevertheless, the additional demand from interrupted customers could have had a significant impact on the distillate market price. If supplies are tight, even relatively small volumes of additional purchases from any source can result in a disproportionate price response. Although volumes resulting from reported gas service interruptions may seem relatively small, they put pressure on a market already under considerable demand stresses. This analysis does not address how much gas interruptions affected price. However, the chapter provides a framework for understanding the complexities of the interruptible gas market.

Interruptible Contracts and Interrupted Service in January–February 2000

Contracts for natural gas delivery service vary among the different gas companies. Some companies offer several different tariff schedules and others offer only one or two types.[6] The distinguishing traits of the contracts are the quality of service offered (firm or interruptible),[7] the triggers for potential interruptions, the requirement for alternative supplies, and other terms or conditions (see Chapter 2, "Triggers for Interruptions," p. 17).

Firm service contracts generally stipulate a maximum daily quantity (MDQ) that the distributor will deliver. In practice, the MDQ often does not impose a strict obligation on the gas supplier because firm service consumers may demand less than the MDQ. However, in periods of high demand the MDQ represents the greatest daily volume of natural gas that the gas company is obligated to deliver to or on behalf of the customer.[8] In contrast to the firm service contracts, interruptible contracts generally do not stipulate an MDQ. However, many of the gas suppliers have planned service levels that specify volumes they anticipate delivering to their interruptible customers if conditions permit. Maximum daily quantities differ from the planned service levels in that the MDQ constitutes the maximal contractual obligation that the gas company must honor, whereas the planned service level embodies an a priori expectation of what the company will deliver if capacity is available.[9] In other words, during periods of high demand the MDQ is compulsory, whereas the planned service level is discretionary subject primarily to available pipeline capacity.

Based on their reported planned service levels, gas suppliers in the Northeast planned to deliver 98 trillion Btu under interruptible contracts during January and February 2000: 14 trillion Btu in New England and 84 trillion Btu in the Middle Atlantic. These potential deliveries under interruptible service provide a useful benchmark with which to compare the actual deliveries during the same period, which totaled 86 trillion Btu in the Northeast: 11 trillion Btu in New England and 75 trillion Btu in the Middle Atlantic.

Compared with the definition of an interruption posited in this report (see Chapter 1, "Defining an Interruption," p. 2), the reported interruption data from EIA-903 overstate the involuntary interruptions that occurred during January and February 2000 in that they include some volumes for customers with seasonal service (that had terminated before the January and February period) and for those who already may have switched to another fuel for economic reasons. Service suspensions specified in seasonal or short-term contracts should not be considered an interruption because these contracts generally stipulate that these customers cease consuming gas at a specific time during the heating season. This implies that the seasonal customers' demand for distillate or other alternative fuels is not directly germane to the current issue of unexpected interruptions of service. Seasonal shifts also are a part of the regular demand load experienced in other fuel markets during the winter, and these sales already should be factored into the suppliers' planning. Seasonal gas service interruptions are a regularly scheduled event that generally occurs prior to

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[6] A tariff is a compilation of all the effective rate schedules for a company, along with general terms and conditions of service, whereas a contract is a legally enforceable agreement between two or more parties who negotiate the specific terms and conditions of the agreement.

[7] Quality of service in this chapter is broadly categorized as either firm or interruptible service. Additional discussion of the numerous distinctions in service quality is located in Chapter 2.

[8] Certain high priority customers, such as residential end users, may not have a limiting MDQ.

[9] Form EIA-903 actually requested, "cumulative maximum daily quantity of gas to be provided under these contracts in each period." Because the MDQ does not strictly apply with regard to interruptible contracts, many of the natural gas companies provided the levels of service that they anticipated delivering as a proxy for MDQs.

January. In contrast, the involuntary interruptions during January and February 2000 were largely unexpected and could have contributed to the sudden unexpected surge in distillate demand.

Despite the likely overstatement of volumes, the interruption data reported by the gas suppliers provide important insights.

- Reported interruptions peaked during the week ended January 22 for both New England and the Middle Atlantic with service interruptions of 1,736 billion Btu and 3,933 billion Btu, respectively (Figure 14). These volumes were approximately half of the planned service levels to interruptible customers for that week.

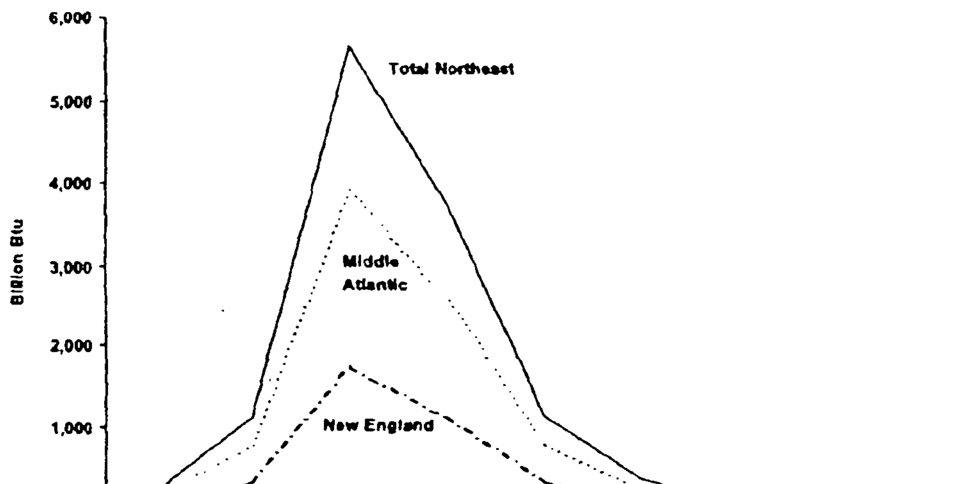
- During the peak week ended January 22, reported interruptions represented the rough equivalent of total planned service levels for interruptible customers in New England but only 39 percent of planned service levels in the Middle Atlantic.

- During the third and fourth weeks of January, reported interruptions totaled 9,399 billion Btu or 76 percent of total interruptions during January and February.

- Cumulative reported interruptions during January and February totaled 3,786 billion Btu in New England and 8,578 billion Btu in the Middle Atlantic, representing 28 percent and 11 percent of the regions' planned service levels, respectively. No firm service customers were interrupted.

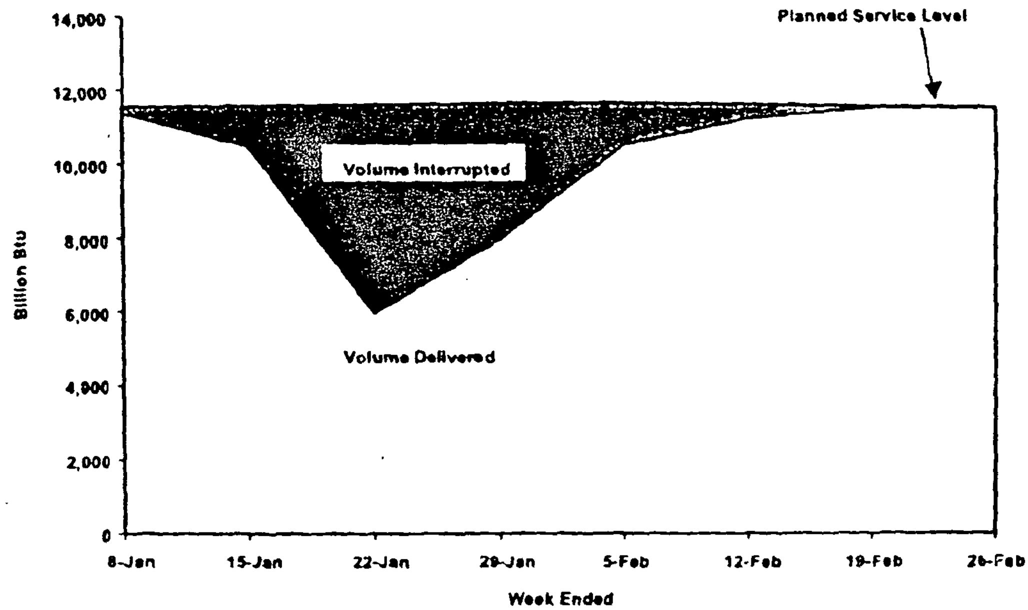
During the third week of January when interruptions peaked, reported interruptions were 5,669 billion Btu of the planned service level of 11,657 billion Btu, so approximately half of the planned service level under interruptible service was actually delivered. However, reported interruptions were relatively small fractions of planned volumes for the entire sample period (Figure 15). The magnitude of the relative surge in reported interruptions in the third week in January underscores the importance of interruptions as a load management tool for distribution and pipeline companies. However, it also shows how the interruptions peak during the worst weather when distillate markets may already confront strong demand pressure.

Figure 14. Reported Natural Gas Volume Interrupted by Week, January and February 2000



Source: Energy Information Administration, Form EIA-903 "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000."

Figure 15. **Planned Level of Service to Interruptible Customers and Actual Volumes Delivered, January and February 2000**



Source: Derived from Energy Information Administration, Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000."

Backup Fuels

Most of the interruptible service customers (in terms of number of customers and volumes interrupted) who were interrupted, as identified by the LDCs and pipeline companies, used distillate fuel oil as their alternative fuel, although the relative dependence on distillate varied between New England and the Middle Atlantic. In the EIA-903 survey, respondents were asked to list the types of interruptible service and the alternative fuels for each customer interrupted, reflecting at least 75 percent of the total volume interrupted or no more than 50 customers. The raw data generated by the survey responses were used to estimate the total for the entire population in the region.[10] The resulting data provide an estimate of the volume of reported interruptions by the types of alternative fuels available to the interrupted end user (Figure 16).[11]

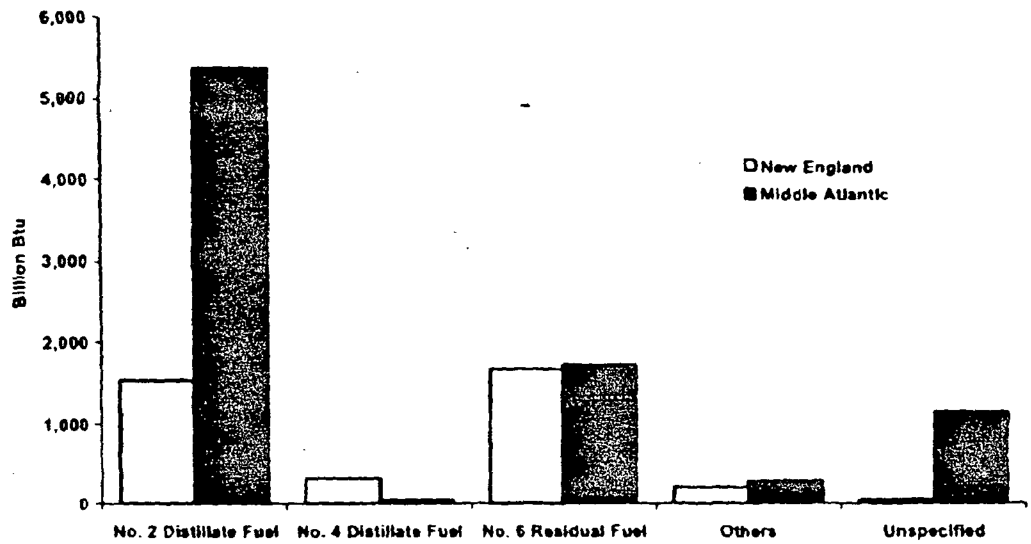
The volumes of interrupted natural gas deliveries were converted into their thermal equivalents in terms of the customer's backup fuel type to provide an estimate of the potential incremental demand for each fuel type (Table 3). For example, the 6,912 million Btu of interrupted volume of natural gas deliveries in the Northeast for customers using No. 2 distillate as backup fuel is equivalent to 1,187 thousand barrels of No. 2 distillate if these interrupted customers chose to offset all the interrupted natural gas with equivalent volumes of distillate.

The volume of reported gas interruptions equivalent to volumes of backup fuels is provided in this report as an indicator of the potential magnitude of backup fuel

[10] The raw sample data accounted for 11.7 trillion Btu of interruptions. This quantity was inflated by 6 percent to generate the population estimate of reported interruptions (12.4 trillion Btu). See Appendix B, Table B1.

[11] The unspecified volumes consist of interruptible customers for which the natural gas companies did not furnish alternative fuel information.

Figure 16. Reported Volume of Natural Gas Interrupted in Terms of Equivalent Volumes of Backup Fuel, for January and February 2000



Note: Other includes kerosene, propane, and power grid.
Source: Energy Information Administration, Form EIA-903 "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000."

purchases. Estimates of average daily volume by week were computed for the volumes of distillate fuel oil equivalent to the volume of reported interruptions for interruptible gas customers in the Northeast identified on EIA-903 as having distillate fuel oil as a backup fuel. Two sets of estimates are provided to reflect uncertainties inherent in the estimates. To account for interruptions by gas service providers outside the respondent group, the pairs of estimates rely on reported volumes that then were expanded to the total volume (Table 4).

The range for average daily potential distillate purchases was between 78 and 84 thousand barrels per day at its peak during the third week of January. This estimate overstates the actual volume of backup fuel purchases to offset the interrupted volumes. Some customers who experienced interruptions suspended or scaled back operations rather than replacing the full volume of interrupted gas supplies with backup fuels. In certain cases, some of the interrupted gas volumes were replaced with backup fuels from inventories rather than with new purchases of backup fuels.

The estimated range of 78 to 84 thousand barrels per day of potential incremental distillate consumption is consistent with estimates published in earlier works. Earlier estimates had indicated that interruptions in natural gas service and economic switching caused an incremental demand of up to 100 thousand barrels per day for distillate fuel oil from the middle of January to early February 2000.[12] Since the earlier estimates include the full volumetric impact of both interruptions and economic switching, they naturally would be larger. If the larger estimates are reliable, the 78 to 84 thousand barrel per day range shows more than 15 percent of the fuel shifting from gas to distillate is due to factors outside gas service interruptions. These distinctions have important implications for further analysis or policy formulation.

[12] Energy Information Administration, *The Northeast Heating Fuel Market: Assessment and Options*, SR/OIAF/2000-03 (Washington, DC, May 2000), p. 44. Petroleum Industry Research Foundation, Inc., *What Happened to Heating Oil?* (March 2000), p. 6.

Table 3. Reported Volume of Natural Gas Interruptions Expressed in Terms of Equivalent Volumes of Backup Fuel, for January and February 2000

Fuel Type	New England	Middle Atlantic	Total Northeast
No. 2 Distillate			
Natural Gas Interruptions (Million Btu)	1,541,142	5,371,213	6,912,355
Fuel Equivalence (Thousand barrels)	264.6	922.1	1,186.7
Percent of Total	40.7%	62.6%	55.9%
No. 6 Residual			
Natural Gas Interruptions (Million Btu)	1,665,795	1,715,556	3,381,351
Fuel Equivalence (Thousand barrels)	265.0	272.9	537.8
Percent of Total	44.0%	20.0%	27.3%
No. 4 Distillate			
Natural Gas Interruptions (Million Btu)	332,360	56,986	389,346
Fuel Equivalence (Thousand barrels)	54.9	9.4	64.3
Percent of Total	8.8%	0.7%	3.1%
Kerosene			
Natural Gas Interruptions (Million Btu)	0	53,298	53,298
Fuel Equivalence (Thousand barrels)	0.0	9.4	9.4
Percent of Total	0.0%	0.6%	0.4%
Propane			
Natural Gas Interruptions (Million Btu)	24,075	84,285	108,360
Fuel Equivalence (Thousand barrels)	0.6	0.0	7.2
Percent of Total	0.7%	1.0%	0.9%
Other			
Natural Gas Interruptions (Million Btu)	173,990	147,360	321,350
Percent of Total	4.6%	1.7%	2.6%
Unspecified			
Natural Gas Interruptions (Million Btu)	48,787	1,148,909	1,197,696
Percent of Total	1.3%	13.4%	9.7%
Total			
Natural Gas Interruptions (Million Btu)	3,786,149	8,577,607	12,363,756

Note: Heat content used for No. 4 distillate was 6.058 million Btu per barrel (MMBtu/barrel), for kerosene 5.670 MMBtu/barrel, and for propane 6.287 MMBtu/barrel. Other includes coal, electricity, jet fuel and shut down.
Source: Derived from Energy Information Administration, Form EIA-903 "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000."

Customer Type

The detailed customer data provided by gas companies on Form EIA-903 were grouped into nine different categories or customer types: electric generation, product manufacturing, chemical and asphalt, textile and paper products, agricultural and food products, educational services, health services, housing, and general services (Figure 17).[13] The most prominent feature that emerges from these groupings is that the electric power generation facilities account for the largest share of interrupted volumes. For the overall sample, electric generation facilities experienced over 25 percent (1,428 billion Btu) of the reported interruptions that were known by industry type (5,583 billion Btu), and among distillate users electric generation facilities experienced over 44 percent (1,252 billion Btu) of the 2,788 billion Btu of interruptions known by industry type (Figure 18).

Although the electric generation facilities constituted the largest volumes among the nine customer types, interrupted volumes to a subset of three of the customer types enumerated above—educational services, health services, and housing—exceeded the interrupted volumes to electric generation facilities. Together, these "human

[13]As described in the box "Human Needs Customers and Interruptible Natural Gas Service" (p. 41), only 50 percent of interrupted volume data were available for this portion of the analysis.

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Table 4. Estimated Volume of Distillate for Complete Replacement of Natural Gas Interruptions by Week in the Northeast, January and February 2000

Week Ended	Percent of Total Reported Interrupted Volume	Average Daily Volumes (Thousand Barrels)	
		Low Case	High Case
January 8	1.8	3	3
January 15	9.2	16	17
January 22	45.8	78	84
January 29	30.0	51	55
February 5	9.5	16	18
February 12	3.3	6	6
February 19	0.2	0	0
February 26	0.1	0	0
February 29	0.1	0	0
Weekly Total	100.0	170	183

Note: Natural gas volumes converted using 5.825 million Btu per barrel of distillate..

Source: Derived from responses to the Energy Information Administration surveys: Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000," and Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition."

needs" interruptible customers accounted for almost 30 percent of the interrupted service volumes among all interruptible customers. Among interruptible customers that use distillate fuel oil as their backup fuel, human needs customers are the second largest group with over 26 percent of service interruptions (see box, "Human Needs Customers and Interruptible Natural Gas Service," p. 41).

How Customers Responded to Interruptions (Form EIA-904)

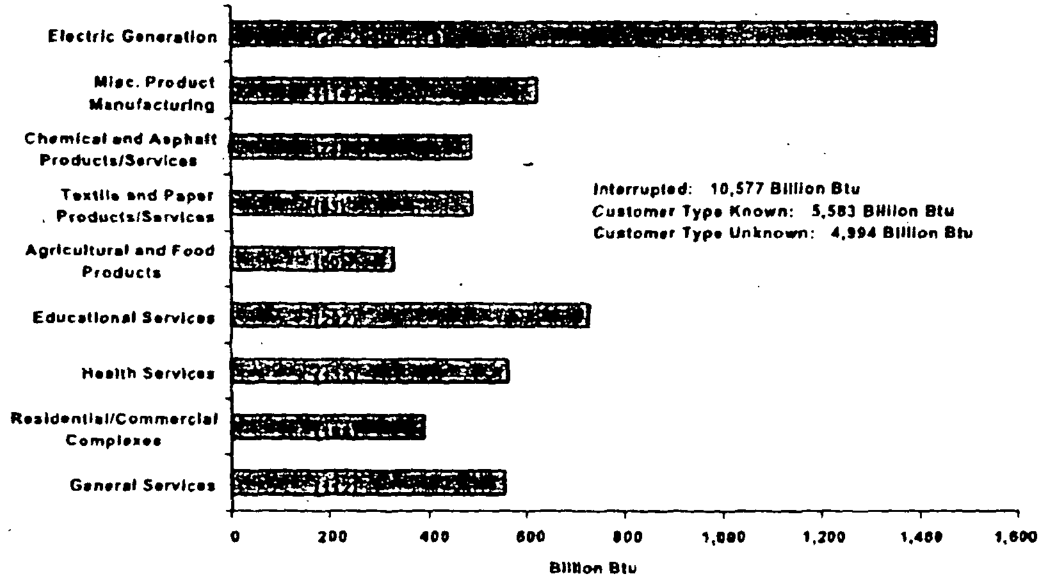
Overview of Customer Survey

For information on purchases, consumption, and inventories, EIA surveyed a sample of gas customers in New England who according to information provided by gas suppliers on Form EIA-903 experienced an interruption in natural gas service during January-February 2000. Because of the emphasis in this report on distillate fuel oil demand, all the customers that were identified as having distillate as a backup fuel were included in the sample. Some customers identified on EIA-903 as not having distillate fuel oil as a backup fuel were also included in the sample to verify the accuracy of the EIA-903 information.[14] These customers were selected on the basis of interrupted volume—the two largest per reporting company—and by a random sample of the remaining New England customers identified by service providers as experiencing interruptions. A total of 97 customers provided responses to Form EIA-904, of which 67 were reported by their gas service provider as using distillate as a backup fuel and 30 were reported as using other backup fuels.

The analysis in this section is based on data from 40 of the 97 customers who responded to EIA-904. These

[14] EIA found several cases where the gas service providers reported the wrong backup fuel for an end user, but the low frequency was judged not significant enough to invalidate the responses overall. In addition, EIA found a number of cases in which the supplier reported that it interrupted a customer's gas supply while the customer reported that it switched to an alternative fuel because it was less expensive.

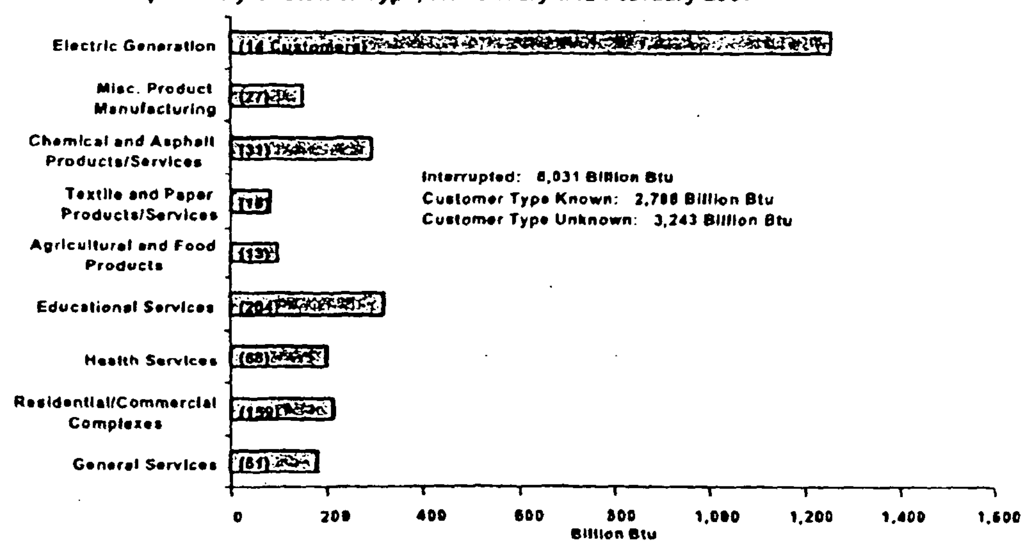
Figure 17. Reported Volume of Natural Gas Interrupted by Customer Type, for January and February 2000



Note: Customer-specific information presented here do not include information for all interrupted customers. The data are not drawn from a complete census or statistical sample.

Source: Energy Information Administration, Form EIA-903 "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000."

Figure 18. Reported Volume of Natural Gas Interrupted for End Users with Distillate Fuel Oil as the Backup Fuel by Customer Type, for January and February 2000



Note: Customer-specific information presented here do not include information for all interrupted customers. The data are not drawn from a complete census or statistical sample.

Source: Energy Information Administration, Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000.

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Human Needs Customers and Interruptible Natural Gas Service

One of the issues surrounding the January to February 2000 event pertained to the type of customer being interrupted from natural gas service. Traditionally, large dual-fired industrial and electric generation facilities, including nonutility generators (NUGS), have been the major users of interruptible natural gas service. However, smaller companies and organizations also have adopted interruptible natural gas service as a way to minimize total energy costs. Some of these smaller companies and organizations, such as hospitals, residential complexes, and schools, are called human needs customers because of the possible impact on the immediate well-being of individuals. This is in contrast to offices, light manufacturers, industries, and others whose operations have a somewhat less immediate effect on individual well-being. Unlike other customers, the suspension of operations by hospitals, residential complexes, and, to some extent, schools is not a viable option for mitigating the effect of an interruption of natural gas service. Reliance on alternative fuels as a backup when natural gas service is interrupted is an essential part of energy acquisition strategies for human needs customers.

The surveys conducted by EIA following the January to February 2000 event provide some insight on the extent of interruptions and the backup fuel situation for human needs customers. Data from the EIA-903 survey sample were grouped by industry to characterize the volumes interrupted during January through February 2000. However, an estimate of all interruptions by industry types was not made because of the high level of nonresponse for the detail needed to categorize customers. In addition, survey response rates varied by region with significantly less detailed data provided in New York, Pennsylvania, and New Jersey, even though total interruptions were more extensive in those states. The results of the EIA-903 survey allowed about 50 percent of the interrupted volume data for January through February 2000 to be identified by industry.

The reported human needs customers, appearing in the educational, health services, and housing/lodging categories, together accounted for about 30 percent or 1,676.5 Btu of the interruptions that could be identified by industry type. EIA survey results document the interruption of 625 human needs users in the Northeast in January through February 2000. The largest reported interruptions on a per customer basis occurred in the health services sector where the average interruption was 4.2 billion Btu for 135 customers for a total of 560.6 billion Btu interruptions in this category. In the education sector, 292 customers experienced a total reported interruption of 726.7 billion Btu for an average of 2.5 billion Btu per school. In the housing/lodging sector, 198 customers experienced a total reported interruption of 389.2 billion Btu for an average of 2.0 billion Btu. Human needs customers relied less heavily on distillate for backup fuel than average for the Northeast (44 percent versus 56 percent).

Since suspension of operations is not a desirable option for most human needs customers, stocks and alternative supplies are crucial. Only 15 human needs customers with distillate backup responded to the EIA-904 survey. The results from the EIA-904 survey indicated that these customers, like others interrupted, purchased to replace fuels burned during the break in natural gas service so as not to deplete stocks. Distillate inventories at human needs facilities prior to the interruptions were the equivalent of 65 billion Btu and ended the last week in February at 48 billion Btu. The 15 responding human needs users, on average, had the capacity to store more than 22 days' worth of consumption on site and had 15 days' worth in inventories.

customers are those who experienced interruptions of natural gas service during January–February 2000, purchased or consumed distillate as a backup fuel, and provided data that were internally consistent. The data obtained from EIA-904 are based on a limited sample and are not conclusive for the overall customer population. Thus, the estimates cannot be aggregated as a measure of the incremental purchases that an influx of interrupted gas customers may have applied on demand in the distillate market. However, the data are useful for illustrative purposes to describe behavior in reaction to shifting market conditions, including gas service interruptions, during the period. As such, they serve as a basis for insights regarding market behavior as an aid for possible policy formulation.

In nearly all cases, natural gas cannot be stored economically by end users. Instead, it is supplied on a just-in-time basis, such that deliveries and consumption coincide, so gas purchases are equivalent to gas consumption. In contrast, distillate consumers must maintain some distillate inventories on site at their facilities. The presence of onsite inventories provides some flexibility in timing of purchase decision for most customers. Once an interruptible customer has decided to offset an interruption to gas service, the customer must also decide how much to purchase and how much to consume from inventory. Because purchases of distillate oil rather than consumption affect the market, purchases are the appropriate variable for measuring the amount of incremental demand for distillate heating oil.

For the majority of the 40 customers, the volume of distillate fuel oil consumed was roughly comparable, in terms of heat content, to the volume of interrupted gas deliveries. In terms of overall volume, however, respondents to Form EIA-904 reported that less than half of the total volume of gas interrupted during January and February 2000 was replaced by the consumption of distillate fuel oil. The lower-than-expected distillate consumption results from the actions of the larger firms, representing over 82 percent of the interrupted volume, who as a group reduced operations rather than use backup fuel to replace all interrupted gas supply. This finding indicates that, all else equal, using the total volume of gas interruptions for customers with distillate fuel oil backup as a proxy for their consumption or purchases of distillate fuel oil overstates their actual consumption or purchases.

The impact of interruptible gas customers on the distillate fuel oil market would have been mitigated if, in response to the suspension of natural gas service, interruptible customers consumed distillate from their onsite inventories rather than purchasing distillate to provide supplies or to maintain inventory levels. Based on information from the EIA-904, about 88 percent of the distillate fuel oil consumed over the 2-month period came from purchases and 12 percent from onsite inventory. Between January 1 and the end of February 2000, onsite inventories reportedly were drawn down by approximately 17 percent.

More important, during the week ended January 22, 2000, when the largest gas interruptions occurred, many smaller volume end users replaced almost 90 percent of their distillate consumption with purchases instead of drawing down inventories. Although the depletion of distillate inventories could not have replaced all of the interrupted natural gas during January and February 2000, using more stocks from inventory and changing the timing of replacement fuel purchases might have reduced the pressure on the distillate market. While these purchasing decisions can be made with accuracy given perfect hindsight, it should be noted that backup fuel purchasing decisions are normally made under conditions of considerable uncertainty. These data suggest that customers maintain multiple days' supply at a fairly stable level. Drawing down stocks before seeking replacement purchases may be perceived as a risk that would jeopardize operations to an unacceptable degree.

Customer Reactions to Interruptions

In evaluating how interruptible natural gas customers responded to interruptions during the January-February 2000 period, partitioning the data set by size of the customer prevents the activities of the large-volume customers from overshadowing the behavior of their more numerous albeit smaller counterparts. Of the 40 customers in the sample, the customer with the largest interruptions reported interruptions over the 8-week period that were more than 10,000 times greater than those for the smallest firm over the same period. Likewise, other variables of interest, such as distillate consumption and purchases, differed across firms by similar orders of magnitude (Figure 19). The four largest firms in terms of volume interrupted constitute over 82 percent of the 897,825 million Btu of total interruptions captured in the survey, while the other 36 firms account for the remainder. Thus, the principal variables of interest aggregated across all firms in the sample can lead to conclusions about the behavior of the typical firm in the sample that may characterize the behavior of the larger firms, but may not accurately describe the behavior of the majority of firms.

Furthermore, the four largest-volume firms in the sample include nonutility generators (NUGs) and cogeneration facilities (cogens). This provides a second rationale for partitioning the sample, as the underlying economics of decisions facing electricity producers may differ significantly from the circumstances that confront the non-electricity producing companies.

Of the customers in the sample, only the power producers use their fuel as a primary variable input to the production process, whereas for the other types the use of fuel takes on a much smaller role in production. For example, electric generation facilities must burn fuel to produce electricity. Therefore, the fuel used in production constitutes a fundamental component of the end product.

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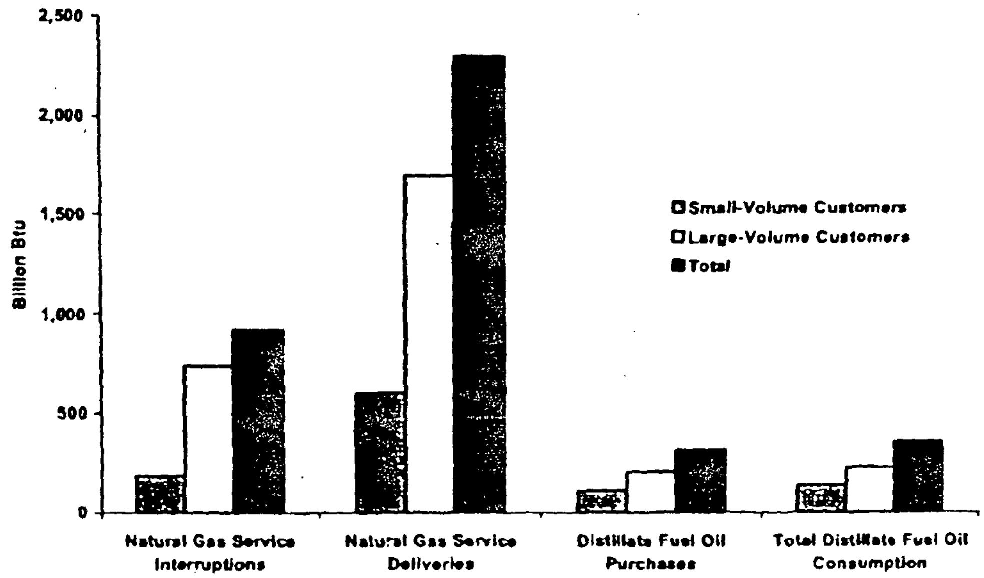
Figure 19. Data Reported by Interrupted Natural Gas End Users in New England During January and February 2000



Source: Energy Information Administration, Form EIA-904 "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000."

Other industrial producers may burn gas, petroleum, or other fuels to power their plants, but other inputs are more integral to the final product or service.

Since the cost of natural gas or oil likely constitutes the dominant portion of the power producers' variable cost structure, one would expect that the amount of fuel purchased by these firms would be greatly affected by changes in the fuel price. Therefore, the prevailing spread between the prices of electricity and the gas or oil that might be used as an input would prove the determining factor in their short-run production decision. In contrast, other types of companies would have a much lower degree of sensitivity in this respect because the fuel cost likely constitutes a much smaller part of their operating costs.

Several conspicuous characteristics emerge from comparing the selected large-volume and small-volume customers that responded to the EIA-904. Key differences include the relative size of storage capacity compared with average daily requirements, inventory management practices, and the extent to which firms replace the gas service interruption with distillate. For example:

- The small-volume customers offset over 78 percent of their interrupted natural gas service with purchases of equivalent volumes of distillate fuel oil during the 8-week period and 78 percent during the third week of January. In contrast, the large-volume customers offset only 28 percent over the 8-week period and 60 percent during the third week of January.
- Both types of customers maintained a fairly constant level of distillate inventories. Throughout the 8-week period the large-volume customers maintained their inventories at an average of about 83 percent full and the small-volume customers maintained inventories at 68 percent of their distillate capacity.
- Based on the maximum potential interruptions, the small-volume customers had 14.3 days of distillate storage capacity available and 9.8 days of distillate inventories on hand. In contrast, large-volume customers had only 3.7 days of storage capacity and 3.1 days of inventory.

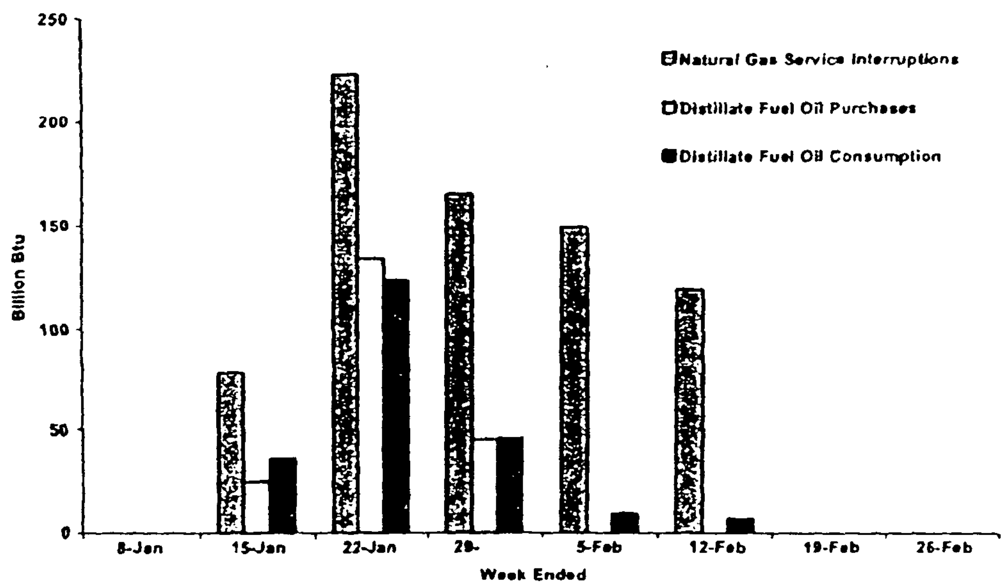
Actions of Large-Volume Customers

Throughout the 8-week period surveyed in EIA-904, the volume of the natural gas service interruptions exceeded the amount of distillate consumption and distillate purchases in each week, because some of the large-volume customers chose to curtail or reduce their operations when their gas service was interrupted (Figure 20). Follow-up interviews with the respondents confirmed the supposition that at least some of the reduced operations for the electric power generators was due to the prevailing conditions in the market that did not warrant paying premium prices for the input fuel.

Distillate purchases and consumption were almost coincident throughout the weekly periods of the sample. Although the large-volume customers did not necessarily replace interrupted gas consumption with distillate consumption, they did burn more fuel than they purchased. The sole exception to this finding occurred during the week ended January 22, when purchases exceeded consumption by 8 percent. However, in any week during the 8-week period, the large-volume customers replaced no more than 56 percent of the volume interrupted by consuming distillate.

Distillate inventories of the large-volume respondents remained almost constant during January and February 2000 albeit with a slight downward trend (Figure 21). Throughout the 8-week period, these companies

Figure 20. Natural Gas Service Interruptions and Distillate Fuel Oil Purchases and Consumption for Large-Volume Customers in New England by Week During January and February 2000



Source: Energy Information Administration, Form EIA-904 "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000."

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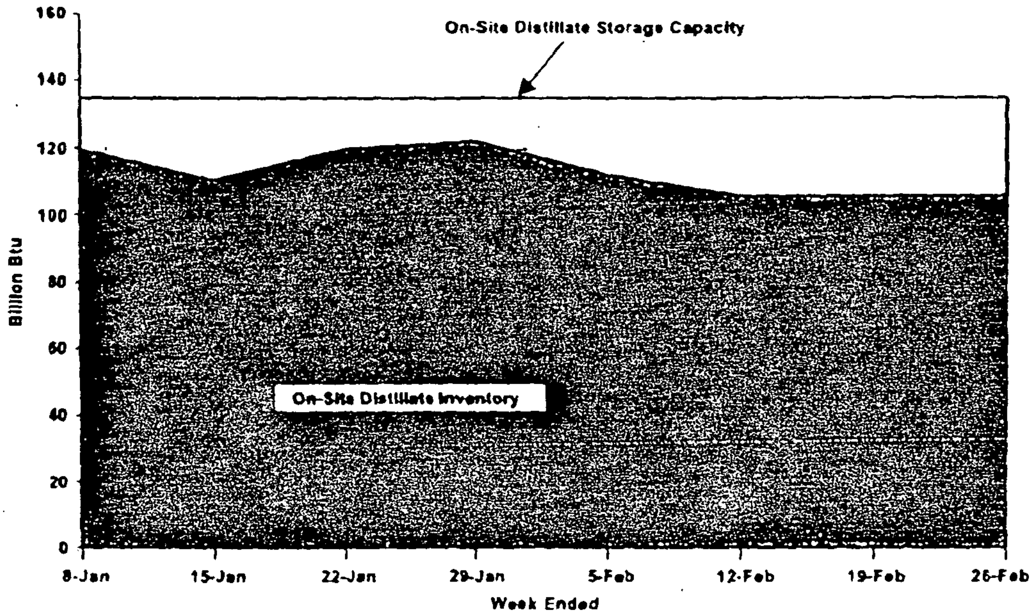
Figure 21. Distillate Inventory and Storage Capacity for Large-Volume Customers During January and February 2000



Source: Energy Information Administration, Form EIA-904 "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000."

maintained their inventories at an average of 83 percent full within a narrow range: 90 percent full at its maximum on the week after the largest interruptions, and 79 percent full in late February.

The large-volume customers would be unable to store enough distillate fuel oil to offset an interruption that lasts more than a few days. During January and February 2000, the large-volume customers had only 3.7 days of distillate storage capacity and 3.1 days of distillate inventories with respect to the potential volume of natural gas service interrupted.[15] However, the apparent lack of distillate fuel oil capacity may simply reflect the broader menu of options available to power producers. For example, the power producer could turn on an entirely different generator rather than use distillate fuel oil in the same dual-fuel unit, or buy electricity from elsewhere.

Actions of Small-Volume Customers

Among the respondents to EIA-904, the reaction of the selected smaller firms to interruptions differed from that of the large-volume customers. The small-volume customers more fully offset the interruption in gas service. Throughout the 8-week period, the small-volume customers offset over 78 percent of the interruptions with distillate purchases and a little over 100 percent of the interruptions with distillate consumption (Figure 22). This diverges from the behavior of the large customers who responded to the interruptions by curtailing operations to a greater extent throughout the period, and so consumption and purchases fell well below the level of interruptions. The large-volume customers replaced only 28 percent of the interruptions with distillate purchases and only 30 percent of the interruptions with distillate consumption.

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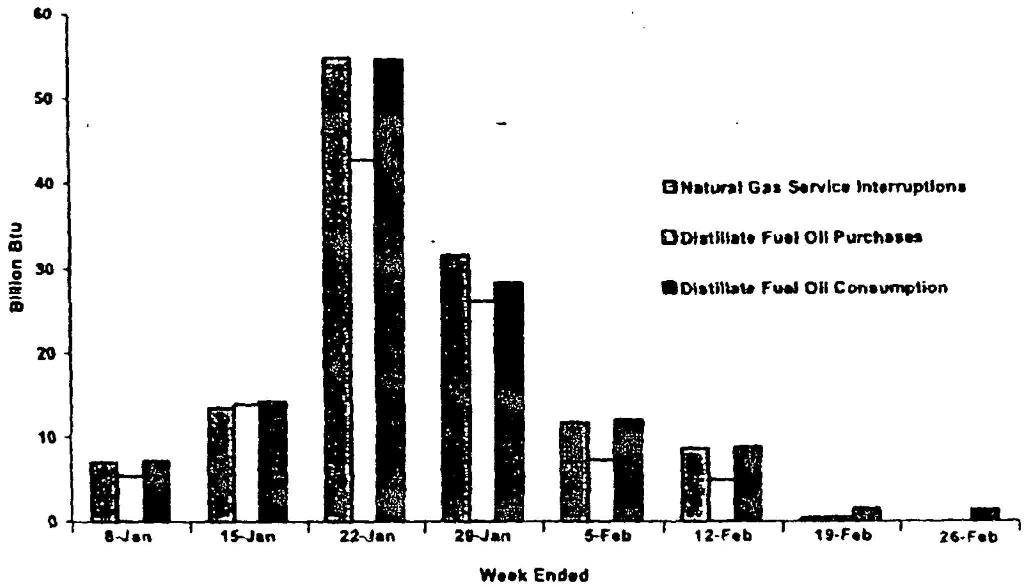
[15]Using data from EIA-904, the number of days of storage capacity was computed by dividing capacity by the maximum average daily interruption that could be replaced. The maximum daily interruption that could be replaced is calculated by computing the 8-week average of natural gas volume delivered plus interrupted natural gas volume, and dividing by 7 days. This result was multiplied by the weighted average of the interruptible firms' assessment of the maximum percentage of natural gas needs that can be offset with distillate fuel oil (83 percent for large-volume customers and 74 percent for small-volume customers). Likewise the days of available inventory was computed by dividing the 8-week average of inventory by the maximum daily interruption that could be replaced.

Figure 22. Natural Gas Service Interruptions and Distillate Fuel Oil Purchases and Consumption for Small-Volume Customers in New England During January and February 2000



Source: Energy Information Administration, Form EIA-904 "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000."

The pattern of distillate purchases and consumption by the small customers also differed from that of the large customers. Through most of the period and especially in the critical third week of January, distillate consumption by small customers exceeded purchases indicating that they relied more on inventories to offset energy volumes affected by gas service interruptions. As a result, the inventories of small-volume customers declined to a greater degree than was the case for the large-volume customers over the 8-week period, although both customer categories experienced a net inventory drawdown.

The small-volume customers had considerable excess capacity: on average they maintained inventories at 69 percent of their distillate capacity with 79 percent as the high during the period and 63 percent as the low (Figure 23). This fairly narrow range of inventories is consistent with the inventory range maintained by the large-volume customers. Although somewhat more variable than the larger customers' inventories, onsite distillate storage stocks for the smaller 36 customers also followed a slightly downward trend during the sample period. It seems that both the large- and small-volume customers pursued a strategy to maintain onsite inventories at target levels. So, like the large-volume customers, the small customers offset the distillate that they consumed with purchases and maintained their inventories. However, the small-volume customers had much greater distillate storage capacity and onsite inventory relative to the potential volume of natural gas service interrupted than the larger customers who could only operate for a few days. During January and February, the small-volume customers had 14.3 days of distillate storage capacity available and 9.8 days of distillate inventories on hand.

Human needs customers (see box, p. 41) accounted for the majority of the interrupted natural gas service volumes among the small-volume customers. One reason is that some of them have their own electric cogeneration units, which they use to produce electricity for their own consumption. Thus some human needs customers have a second alternative in addition to distillate fuel oil when confronted with an interruption in natural gas service.

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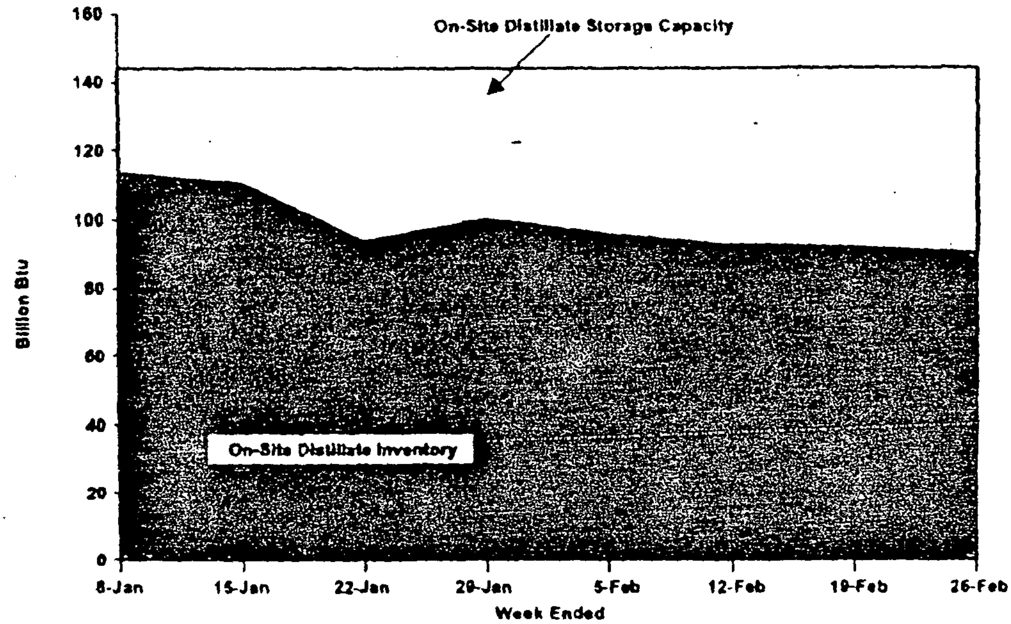
Figure 23. Distillate Fuel Oil Inventory and Capacity for Small-Volume Customers During January and February 2000



Source: Energy Information Administration, Form EIA-904 "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000."

This possibility may mitigate both their exposure to gas service interruptions and their impact on the distillate fuel oil market.

Summary

The survey of gas suppliers (the LDCs and pipeline companies) indicates that while substantial volumes of gas service were interrupted, the aggregate volumes were less than a number of the early estimates that were used in the trade press and elsewhere during last winter. The investigation of customer behavior further indicates that one cannot simply equate the volumes of gas service interruptions with an increase in the aggregate demand for distillate in the entire Northeastern distillate market. Some customers relied on inventories for at least some of their fuel oil requirements, and both classes of customers generally burned less than an equivalent amount of distillate fuel oil.

The present end-use data indicate that a substantial portion of the total gas interruption during the critical third week of January simply resulted in a lower level of operations for some customers. This outcome reduced some pressure that otherwise might have been imposed on the distillate market. A key portion of the reduction in overall energy demand was on the part of electric generation operators, who made the decision based on relative prices not to pursue distillate purchases. Thus, if electric demand, and consequently prices, had been strong enough to justify those purchases of distillate fuel oil, the price pressure on the distillate market would have increased more than it did.

Although the volumes of incremental distillate fuel oil demand driven by gas service interruptions are estimated at smaller amounts than previously expected, the findings of the present analysis highlight the complexities of these energy markets and their potential influence on each other. The present analysis provides findings that indicate the causes for fuel switching include business decisions as well as gas industry performance. Customer reactions to gas service interruptions are varied, reflecting differing operational objectives and economic circumstances.

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5. Conclusion

The information on the weekly distribution of interruptions indicates that the greatest level of interruptions during the 1999-2000 winter was focused on the third week of January. Seventy-six percent of all reported interruptions[1] during January and February 2000 were contained in the third and fourth weeks of January. The analysis in this report shows that reductions in gas service due to reported interruptions for customers in the Northeast with distillate fuel oil as their backup were the equivalent of 78 to 84 thousand barrels per day of distillate during the peak week ended January 22. Average daily distillate consumption in the Northeast in January 2000 was 731 thousand barrels per day but probably rose above this level during the peak week. Actual distillate *purchases* resulting from the reported interruptions likely were less than the corresponding equivalent volume of distillate fuel oil, because some interruptible customers reportedly shut down operations temporarily while others drew down inventories slightly.

The estimated range of 78 to 84 thousand barrels per day of potential incremental distillate consumption is consistent with previously published estimates, which ranged up to 100 thousand barrels per day for distillate fuel oil for both interruptions and economic switching combined. If the larger estimates are reliable, the 78 to 84 thousand-barrel-per-day range clearly shows that more than 15 percent of the fuel shifting from gas to distillate is due to factors other than gas service interruptions.

These distinctions have important implications for further analysis or policy formulation. Understanding motivations behind customer behavior is essential to understanding gas and fuel oil markets at critical times of the year. This is particularly important for possible policy formulation to handle potential conditions leading to price spikes since the motives behind fuel switching differ greatly depending on whether they are caused by involuntary interruptions, seasonal contracts, or voluntary switching because of relative prices.

This study provides better information than previously available on the magnitude of fuel switching from gas to alternative fuels. It also contains information on customer behavior during the winter heating season, including times of intense demand when interruptible gas service is not available. As such, this study provides a framework for improved understanding of the issues.

[1] As described in Chapter 4, *reported interruptions* include some portion of volumes as a result of seasonal switching and economic switching in addition to interrupted gas volumes.

Distillate Market Dynamics

The distillate fuel oil price depends on a number of factors affecting demand and supply. Distillate demand consists of both demand from its regular users and demand from dual-fired users that may utilize distillate fuel oil periodically. Demand by the regular distillate customers depends on general economic conditions and weather, which affects heating requirements. Incremental demand for distillate fuel oil during the heating season consists primarily of demand by regular customers for distillate fuel oil for heating purposes and fuel-switching, both of which may be relatively inelastic. Energy demand for heating tends to be relatively unresponsive to price. Distillate demand for fuel-switching customers is driven by demand for produced output, whether electricity or industrial goods, which if sufficiently strong can cause the derived demand for energy by fuel-switching customers to be inelastic within a wide range of relative prices. Additionally, energy used for industrial applications generally is not a large portion of costs, so price increases may be absorbed within the cost structure for the overall operation.

Supply of distillate fuel oil depends on the flow of current production from refineries, interregional product transfers, imports, and inventories. If distillate demand expands to the limits of current supply, the market adjusts primarily by increasing prices, and additional demand from any source can result in a disproportionately large price response. At times of the most severe temperatures, demand for distillate surges, and gas service interruptions likely peak. These changes add to the demand pressure on a market that may already be close to its limits.

Distillate fuel oil price spikes historically have depended on a combination of conditions, which are not the same in all occurrences. As abnormally cold temperatures set in, low distillate fuel oil inventories may play a role in higher prices, but low inventories alone are not able to drive up prices as indicated in the market experience in 1996. Gas service interruptions contribute some portion of incremental demand at peak, but these volumes by themselves are not responsible for distillate fuel oil price spikes. Gas service interruptions typically occur throughout the heating season, yet these events do not automatically result in distillate fuel oil price spikes. As discussed in Chapter 3, larger distillate fuel oil price spikes generally coincide with a disruption of one or more supply elements.

Customer Behavior

Customers who opt for interruptible gas service must have a strategy to respond to a possible suspension of gas service. A customer's choice should reflect the relative cost and benefits associated with each decision, which will vary depending on characteristics such as location or fuel-use technology for the particular application. The responses generally are one of two: shut down or burn an alternative fuel (although interrupted customers in a few cases were able to arrange continued gas deliveries through another supplier). If customers whose gas service has been interrupted choose to burn their alternate fuel, they face a secondary decision regarding replacement of at least some portion of the inventory drawdown with purchases of additional fuel.

The fuel oil purchase decision will be driven by the customers' perception of the adequacy of onsite inventory and the market conditions for the alternative fuel. The relative size of onsite inventory indicated by days-supply, as measured by the ratio of inventory to daily planned service, differs widely between large-volume interruptible customers and the small-volume users. Large-volume users had inventory equal to an average of 3.1 days supply. Small-volume users had capacity equal to requirements for almost 10 days.

The number of days supply reported by the large-volume customers is larger than previously hypothesized. Some analysts suggested that interruptible customers are compelled to enter distillate fuel oil markets immediately to purchase additional supplies. However, the levels held in onsite inventories by dual-fired energy customers in January and February 2000 represent a significant volume. While some concerns about the "Y2K" transition may have motivated the inventories recorded in the survey, the Y2K factor does not explain the customers' ongoing interest in replenishing their stocks in late January and early February, especially when distillate prices had spiked. When customers began to burn supplies, they initiated purchases to replenish their stores. So interruptions may lead to a fairly automatic response of purchases, but it is not because fuel is not on hand. Instead, it is likely that customers have a standard level that is consistent with avoiding the risk of running out. Their aggregate behavior is such that in effect they offset most of their consumption with incremental purchases.

The Choice of Natural Gas or Petroleum

Fuel-switchable customers, who predominantly burn natural gas, can be an opportunity or a problem for operators in the alternative fuel markets. The infrequent purchases, unless they can be met from "current" supplies (domestic refinery production, interregional transfers, or imports), may result in problems of inventory management and customer relations for petroleum suppliers.

Carrying inventory to meet customer demands imposes a cost on petroleum suppliers. The low probability of sales to customers with irregular and infrequent purchases reduces expected net returns. Potential sales are uncertain and even when they occur are apt to be only for a brief period and typically during the heating season. The costs of unused inventories must be either recovered as an incremental charge from their regular customers or absorbed by the owners. In fact, petroleum suppliers, like many other industries, have shifted increasingly to a "just-in-time" delivery system that attempts to minimize the volume of inventory in serving all customers as an approach to managing costs.[2] This reaction to competition has lowered inventories, which reduces the industry backup to use for demand surges or disruptions in current supply.

The net benefits from the use of interruptible gas service depend on both the advantages of this service and the associated costs. In a broader perspective, it has been argued that dual-fired customers and their switching behavior promote efficiency because they switch from a scarce fuel (with higher prices) to one that is relatively more abundant (with lower prices). The economy at large benefits from the use of interruptible service by avoiding underutilization of gas industry infrastructure during non-peak periods and from energy at lower costs than otherwise would be the case. Not all the consequences of interruptible gas service are positive, however. When substantial interruptions occur, they may coincide with

[2]See, for example, "For Heating-Oil Firm in Vermont, Now Is the Winter of Discontent," *Wall Street Journal* (December 29, 2000).

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already tight conditions in the petroleum product markets. The incremental demand from fuel-switching customers consumes a portion of the scarce supplies, and when petroleum prices rise it logically contributes at least some part of the price increase. The unexpected occurrence of sudden price shocks in the petroleum markets imposes an economic cost beyond the higher prices on participants in those markets. Costs resulting from gas service interruptions are a clear offset that reduces the net benefit of interruptible service. A thorough analysis of the economic merit of interruptible gas service is beyond the scope of the present study. However, the present work provides a set of data and other information that can serve as a useful basis for understanding the complexities of the interruptible gas market.

Implications for Energy Markets

Energy suppliers' best efforts to perform well may achieve benefits to the economy but they also may establish the foundation for episodes of market price spikes. The reduced energy prices because of the increased competition facing gas or petroleum suppliers provide benefits to consumers and the economy at large, but they undermine incentives to maintain infrastructures or inventories at levels sufficient to accommodate peak customer requirements in all situations.

Although the availability of low-cost fuel supply options creates economic benefits in most years, the resulting actions also can contribute to price fluctuations during severe winter events. These price increases can be a particular difficulty for customers on fixed or low incomes who receive fuel oil deliveries during times of elevated prices. In addition, small commercial consumers who rely on petroleum products to satisfy energy requirements also may find their financial resources strained. The impact of these disruptions, as they influence fuel choice decisions and inventory planning, may offset some of the perceived benefits. However, expansion of the gas supply infrastructure to levels adequate to eliminate interruptions of gas service for all current users tends to be economically unattractive or infeasible.

Expansion of the gas delivery system would require substantial levels of new investment, the costs of which must be recovered in user fees in order to be economically justified. Additionally, seasonal demand for a significant portion of the customer base would result in unutilized capacity for some portion of the year. The operators of gas capacity, whether old or new, have an economic incentive to expand net revenues by increasing the total amount of service. Operators would either seek out new business that could not be offered continuously throughout the year (i.e., seasonal or interruptible service) or accept the presence of a productive asset being idle and not providing any return to the company.

Clearly this area of market behavior is a complex topic. Even if interruptible contracts had a limited role in recent fuel oil price spikes, that influence may be expected to increase over time. The trend for the distillate market, especially heating oil, in the Northeast has been toward declining volumes sold. Thus, the customer base is not expanding and the associated industry infrastructure and inventories are smaller. So even without further growth, the relative impact of present levels of fuel switching will grow relative to the regional distillate supply. Meeting the needs of regular and periodic customers will be an expanding challenge for market participants.

Appendix A

Analysis Request

JOSEPH I. LIEBERMAN
CONNECTICUT

COMMITTEES:
ARMED SERVICES
ENVIRONMENT AND PUBLIC WORKS
GOVERNMENTAL AFFAIRS
SMALL BUSINESS

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February 4, 2000

The Honorable William Richardson
Secretary
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Secretary Richardson:

I am writing to request an immediate investigation into the prevalence and use of interruptible natural gas contracts and their impact on heating oil supply in New England, and prompt steps to alleviate any adverse consequences. My office has recently learned of a potentially large problem resulting from these types of contracts, under which a customer benefits from lower rates by accepting a contract for natural gas delivery that may be interrupted at the discretion of the gas supplier when supplies are limited and demand is high.

I understand that the recent supply shortage of home heating oil and continuing price spike in the Northeast is now being exacerbated by demand from interruptible natural gas contract-holders. Apparently, a large number of these contract-holders were told by their gas suppliers at the beginning of last week that they temporarily would not have access to natural gas for heating their homes. As a result, many of these customers turned to home heating oil as a substitute, which, according to the heating oil delivery industry, may be increasing demand by as much as two million gallons per day.

This type of interruptible contract may have the unintended consequence of contributing to heating oil price spikes and supply shortages. It has and may continue to account for unanticipated demand for home heating oil; these additional demands have the capacity to cripple the market in times of stress. I would like to know more about the extent of, the need for, and the potential consequences of interruptible contracts. Please promptly survey the extent of interruptible gas contracts and the level of new demand they may be adding to the heating oil market in the Northeast. Specifically, I would like to know the answer to the following questions:

- At what point do natural gas contractors refuse service to interruptible gas contract-holders?

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- How often in the recent past have users of interruptible gas contracts created a significant unforeseen demand on home heating oil in the Northeast?
- Do interruptible gas (or other fuel source) contracts threaten the stability of the home heating oil market?
- What other backup fuels do interruptible contract users utilize?
- If you confirm there is a significant problem, what steps will you take in cooperation with industry to promptly alleviate it?

Thank you for your continued interest in this issue.

Sincerely,

Joseph I. Leiberman
United States Senator

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Appendix B

Survey Data

Appendix B

Survey Data

In February 2000, Senator Joseph Lieberman of Connecticut requested an investigation into the prevalence and use of interruptible natural gas contracts and their impact on heating oil supply in New England. Specifically, Senator Lieberman requested that the Department of Energy (DOE) "promptly survey the extent of interruptible gas contracts and the level of new demand they may be adding to the heating oil market in the Northeast."

Two survey forms were developed in response to this request: Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, January and February 2000," OMB No. 1905-0199, and Form EIA-904, "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000," OMB No. 1905-0200.

The Energy Information Administration (EIA) coordinated the development of the forms with staff from the Federal Energy Regulatory Commission (FERC), Interstate Natural Gas Association of America (INGAA), American Gas Association (AGA), New England Gas Association (NEGA), and the New York Public Service Commission (NYPSC). These consultations did not, however, include specific discussion of the detailed questions incorporated into these questionnaires. Additional preparatory work did include discussion of the form with two potential respondents and a review of a draft questionnaire by a manufacturing trade association.

Form EIA-903

Form EIA-903 initially was sent to nine local distribution companies (LDCs) in four of the Northeast States (Connecticut, Massachusetts, New Jersey, and New York). This allowed initial testing of the questionnaire prior to full distribution. These companies were selected on the basis of the amount of interruptible natural gas deliveries and the magnitude of gas volumes delivered to industrial (including nonutility generation) and electric utility sector end users in each state. These sectors are believed to be most affected by gas-service interruptions. The EIA-903 was subsequently sent to 21 additional LDCs and four pipeline companies. Based on responses to Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," for 1998, the latest year for which interruptible delivery data were available, the 34 gas suppliers surveyed accounted for 94 percent of the natural gas deliveries to interruptible gas customers in the Northeast in 1998. The interruptible deliveries represented by surveyed gas companies in each state varied from 92 percent in New Jersey to 100 percent for three New England states. The state-level information was used to estimate the total interruptions to account for those gas service providers not included in the EIA-903 survey (Table B1).

Form EIA-903 consists of six parts:

- Part I identifies the company and requests contact information and conversion factors from volumes of gas to Btu heat content to allow the analyses of different respondent data on a uniform basis.
- Part II A asks the company to describe its interruptible gas service tariffs or contract categories. Part II B asks the company to list, for all tariffs and contract categories listed in Part II A, monthly data for December 1999, January 2000, and February 2000, and weekly data for January and February 2000. The requested data include the maximum daily quantity, total deliveries interrupted in each period, number of days interrupted, and the number of days of service with flow restrictions to customers.
- Part III asks for the company to list its customers who were interrupted during January and February 2000. Specifically, Part III asks for the customer name, volume interrupted, customer contact person, phone number or e-mail address, and the type of the alternative fuel capability for each customer that could have been used in January-February 2000 to replace the volume of gas that was interrupted.
- Part IV requests maximum daily quantity and total interruptions for firm service contracts.
- Part V asks for a list of interrupted firm service customers.
- Part VI asks for a list of customers who declined gas service after interruptions were ended, whether under a firm or interruptible contract.

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Table B1. Natural Gas Interruptions in the Northeast During January and February 2000, by State

State/Region	Raw Data from Form EIA-903 (MMBtu)	Respondents' Share of 1998 Interruptible Gas Deliveries (Percent)	Estimated Natural Gas Interruptions (MMBtu)
New England			
Massachusetts	2,507,687	97	2,585,244
Other	1,184,029	98	1,200,905
Total	**3,691,716**	**97**	**3,786,149**
Middle Atlantic			
New York	2,325,640	94	2,474,085
Other	5,629,555	93	6,103,522
Total	**7,955,195**	**93**	**8,577,607**
Northeast	**11,646,911**	**94**	**12,363,756**

MMBtu = Million Btu.

Source: Energy Information Administration. **Raw Data:** Part II of Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000." **1998 Share of Interruptible Gas:** Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition" (1998).

To aid its analysis, EIA assigned a Standard Industrial Classification (SIC) code and description to more than 1,000 customers listed in the responses to Part III of EIA-903. The addition of the SIC codes allowed for an analysis of interruptions by business sector. The two-digit SIC codes were grouped into the following categories:

- Agricultural/Food Products: 01-16, 18-21, 51
- Textile and Paper Products/Services: 22-27
- Chemical and Asphalt Products/Services: 28-29
- Misc. Product Manufacturing: 30-39, 50, 52-59
- General Services: 17, 40-45, 62-64, 66-69, 71-79, 83-97
- Electricity Generation: 49
- Health Services: 80
- Educational Services: 82
- Residential/Commercial Complexes, Lodging: 65, 70.

The interrupted volumes from Part III as classified by SIC code are shown by category in Table B2. Most of the interrupted volume in the Middle Atlantic region could not be classified into SIC category, whereas over 99 percent of the New England volume was assigned SIC codes. The total volume reported in Part III of Form EIA-903 of 10,577,444 MMBtu is less than the Part IIB total of 11,646,911 MMBtu because respondents were not asked to provide information on all interrupted customers. Part III of EIA-903 requested customer information for at least 75 percent of total gas interruptions, up to a total of 50 customers. In practice, many respondents provided information for a larger number of customers.

In most cases gas service providers reported their interrupted customers' alternative fuel on Part III of the EIA-903. EIA conducted a followup investigation with customers to identify the alternative fuel information which was not reported by the gas companies. Through this followup investigation, EIA was able to assign the proper alternative fuel to customers who represented over 50 percent of the interrupted volumes for which this information was missing. EIA was also able to allocate interrupted volumes of gas accurately among the various alternative fuels for several respondents. After the direct assignments and allocations were completed, EIA assigned the remaining interrupted volumes with unreported alternative fuels to an "unspecified" category.

In total, backup fuels were identified on the EIA-903 Part III for 99 percent of the interrupted volumes in New England and 87 percent of the interrupted volumes in the Middle Atlantic region (Table B3). At the state level, the calculation for alternative fuel resulted in completed assignments for New Jersey, Connecticut, Maine, New Hampshire, Rhode Island, and Vermont. Massachusetts was 92 percent complete, while New York was 75 percent complete and Pennsylvania 65 percent complete.

Table B2: EIA-903 Part III Interruptions and Customers by SIC Group and Region

Customer Category (SIC/Unknown)	Northeast		Middle Atlantic		New England	
	Volume (MMBtu)	No. of Customers	Volume (MMBtu)	No. of Customers	Volume (MMBtu)	No. of Customers
SIC Group						
Chemical / Asphalt	486,171	73	385,943	48	100,228	25
Textile & Paper	488,265	63	82,608	27	405,657	36
Educational Services	726,691	292	342,160	230	384,531	62
Agricultural / Food	330,392	50	145,464	33	184,928	17
Health Services	560,625	135	280,391	77	280,234	58
Residential/ Commercial	389,224	198	255,467	152	133,757	46
Misc. Product Man	619,644	114	141,119	38	478,525	76
Electricity Generation	1,428,398	22	321,205	10	1,107,193	12
General Services	553,734	112	269,368	52	284,365	60
Total SIC Group	5,583,403	1,059	2,223,985	667	3,359,418	392
Unknown	4,994,041	21	4,966,801	12	27,240	9
Total	**10,577,444**	**1,080**	**7,190,786**	**679**	**3,386,658**	**401**

SIC = Standard Industrial Classification. MMBtu = Million Btu.

Source: Energy Information Administration, Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000."

Table B3. Share of Natural Gas Interruptions by Alternative Fuel and State/Region for January and February 2000

State / Region	No. 2	No 4	No 6	Other	Unspecified
New England					
Massachusetts	42.8	7.0	48.2	0.2	1.9
Other	36.3	12.6	35.0	16.2	0
Total	**40.7**	**8.8**	**44.0**	**5.2**	**1.3**
Middle Atlantic					
New York	53.7	2.0	9.7	9.1	25.6
Other	66.2	0.1	24.2	1.0	8.5
Total	**62.6**	**0.7**	**20.0**	**3.3**	**13.4**
Northeast	**55.9**	**3.1**	**27.3**	**3.9**	**9.7**

Note: Other includes propane, jet fuel, kerosene, electricity, coal, and shut down. Unspecified includes not specific, none specified, and no alternative fuel.

Source: Energy Information Administration, Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000," Part III.

The percentages shown for alternative fuel types in Table B3 include these EIA adjustments achieved in followup contacts.

Data Adjustments

As discussed earlier, EIA performed a significant amount of followup work to correct and complete the responses to the EIA-903. However, additional adjustments were required before EIA could conduct an analysis of natural gas interruptions and their impact on fuel oil markets in the Northeast. These adjustments were necessary because the EIA-903 survey was not sent to every gas service provider in the Northeast region and the surveyed gas companies were not asked to provide information on all interrupted customers. EIA first estimated the total volume of interrupted gas reported on Part II of Form EIA-903 to account for those gas companies in the Northeast that were not included in the survey. As stated earlier, the 34 companies surveyed represented about 94 percent of the 1998 annual interruptible natural gas deliveries in the Northeast, with individual state coverage ranging from 92 to 100 percent. The state percentages were applied to the respective total gas interruption by state derived from Part II of EIA-903 resulting in an increase from the reported interruption (raw data) of 11,646,911 MMBtu to a total reported interruption of 12,363,756 MMBtu in the Northeast for January and February 2000 (Table B1).

Once the raw interruption data were estimated to represent the entire Northeast region, EIA separated the interruptions among the various alternative fuels to assess the potential volumetric impact that natural gas interruptions may have had on the distillate market and other alternative fuel markets. The assignment of natural gas interruption volumes to alternative fuels was accomplished using the information from Part III of EIA-903. The alternative fuel information derived from Part III (Table B3) was used to allocate the inflated gas interruption of 12.4 trillion Btu among the various alternative fuel and unspecified categories. The allocation was performed on each state's data and summed to arrive at the regional totals of natural gas interrupted by associated alternative fuel.

This procedure provided a base line estimate for the total volume of gas interruption that could have affected the No. 2 fuel oil market in the Northeast during January and February 2000. A second or high estimate of the volume of gas interrupted with No. 2 as an alternative fuel was developed by assigning half of the unspecified volumes to the No. 2 category. Table B4 details the results of these calculations. The numbers shown in Table B4 were then used for the analyses, tables, and charts in the body of this report.

Form EIA-904

EIA developed a customer survey to collect specific information about customers' alternative fuel capabilities and activities during a natural gas service interruption and to check information provided by the natural gas service providers. Form EIA-904 was a customer-oriented survey designed to collect weekly information for January and February 2000, including the volumes of gas delivered, the volumes interrupted, the days interrupted, and the alternative fuel use including volumes purchased and consumed and weekly inventory levels and storage capacity. A customer in the EIA-904 survey was a consuming site so a single company with multiple sites comprises multiple customers.

Form EIA-904 was targeted to all customers identified in the responses to Form EIA-903 that were interrupted and had distillate fuel oil as a backup fuel to natural gas. Additional customers who were reported to have an alternative fuel other than distillate were also included in the survey to cross check the responses to the EIA-903. Customers in New York, New Jersey, and Pennsylvania were not included in the EIA-904 survey because responses to the EIA-903 from gas service providers in these states were received after the mailing date for the EIA-904 survey. As a result, the EIA-904 sample was not statistically designed to collect information from the entire Northeast region. The results from the analysis of EIA-904 data are provided as illustrative, but they are not definitive for all customers in the Northeast and the results cannot be aggregated for regional totals.

Survey forms were mailed to 101 potential respondents, three of which duplicated other EIA-904 requests and one customer who was dropped because it could not be contacted by phone or mail, resulting in responses from 97 unique customers. Follow-up contact was made with every customer in the EIA-904 survey reported to have been a distillate user, to verify whether No. 2 distillate fuel oil was in fact the alternative fuel source to natural gas, and to ensure internal consistency of the reported data.

Table B4. Estimated Natural Gas Interruptions by Alternative Fuel Capability, January–February 2000 (Million Btu)

State / Region	Total	No 2: Low Estimate	No 2: High Estimate	No 4	No 6	Other	Unspecified
New England							
Massachusetts	2,585,244	1,105,676	1,130,070	180,992	1,245,851	3,938	48,787
Other	1,200,905	435,466	435.466	151,368	419,944	194,127	0
Total	**3,786,149**	**1,541,142**	**1,565,536**	**332,360**	**1,665,795**	**198,065**	**48,787**
Middle Atlantic							
New York	2,474,085	1,328,588	1,645,140	48,768	239,394	224,232	633,103
Other	6,103,522	4,042,625	4,300,528	8,218	1,476,162	60,711	515,806
Total	**8,577,607**	**5,371,213**	**5,945,668**	**56,986**	**1,715,556**	**284,943**	**1,148,909**
Northeast	**12,363,756**	**6,912,355**	**7,511,203**	**389,346**	**3,381,351**	**483,008**	**1,197,696**

Note: Other includes propane, jet fuel, kerosene, electricity, coal, and shut down. Unspecified includes not specific, none specified, and no alternative fuel.

Source: Energy Information Administration, Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000."

Discrepancies Between EIA-903 and EIA-904 Results

Several customers surveyed by Form EIA-904 reported data that were inconsistent with the information provided on EIA-903 by their gas supplier (Table B5). In some cases, there were differences in the backup fuels identified as being useable for a given customer. Of the 97 respondents to EIA-904, 67 were identified as having No. 2 distillate as an alternative fuel by their gas service providers on Form EIA-903, while only 50 of those customers surveyed reported having No 2 distillate alternative fuel capability. In all cases that this discrepancy occurred, the customer information on the EIA-904 was assumed to be more reliable because they were reporting on their own operations. In addition, about 40 percent of the EIA-904 respondents claimed that no interruption of service occurred during January-February 2000, whereas their service provider reported on EIA-903 that an interruption of service did occur during the period. The EIA-904 respondents stated that either they had a seasonal contract and therefore did not expect to receive gas, that they voluntarily switched to their alternative fuel for economic reasons, or they in fact continued to receive gas throughout the reporting period.

Insights

Although responses to Form EIA-904 accounted for only a small portion of the natural gas interruptions in the Northeast (less than 10 percent of the interrupted customers and about 18 percent of the interrupted volume reported on Part III of EIA-903), EIA gained valuable insights through these data and information gathered through the follow-up investigation of EIA-903 information. EIA found a number of customers in both surveys that continued to receive gas from their original supplier or a different supplier while the gas service provider reported that the customer was interrupted. In addition, there were several instances in which the gas companies reported customers as interrupted when in fact the customers received gas under seasonal contracts which do not provide gas service during the months of January and February.

2706

DOE006-0063

Table B5. Difference Between EIA-904 and EIA-903 Survey Information About Companies Used in the EIA-904 Sample

Respondent Information	Reported on Form EIA-903: Number of Companies			Reported on Form EIA-904: Number of Companies			
	With Distillate Capability	Without Distillate Capability	Total	With Distillate Capability	Without Distillate Capability	Alternative Fuel Unknown	Total
Interrupted and Consumed Distillate	62	–	62	41	–	–	41
Interrupted and Consumed Other Fuel	–	26	26	2	10	–	12
Not Interrupted	5	4	9	6	4	29	39
Data not cleaned	–	–	0	1	2	2	5
Total	67	30	97	50	16	31	97

Source: Energy Information Administration, Form EIA-903, "Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000," and Form EIA-904, "Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000."

Another group of customers reported that they decided to consume their alternative fuel and cease gas consumption for economic reasons. Some of the largest-volume end users in the region reported that they suspended or curtailed operations instead of consuming an equivalent amount of alternative fuel to replace their interrupted supply of gas. Therefore, the total volume of gas interrupted with No. 2 as an alternative fuel may likely be an upper bound when attempting to assess the impact of natural gas interruptions on the distillate market.

2707

DOE006-0064

Appendix C

Survey Forms:

Form EIA-903 and Form EIA-904

Form EIA-903

Natural Gas Service Interruptions in the Northeast During December 1999, and January and February 2000

Form Approved
OMB No. 1905-0199
Expires: 09/30/2000

U.S. DEPARTMENT OF ENERGY
Energy Information Administration
Washington, D.C. 20585

FORM EIA-903
NATURAL GAS SERVICE INTERRUPTIONS IN THE NORTHEAST DURING DECEMBER 1999, AND JANUARY AND FEBRUARY 2000

I. PURPOSE

The Form EIA-903 "Natural Gas Service Interruptions in the Northeast during December 1999, and January and February 2000" is designed to collect information concerning only those natural gas service arrangements respondent companies have with end users, i.e., those who burn or otherwise use the fuel. Any arrangements for deliveries to other natural gas service providers or distributors should be excluded. This information is being requested on a State basis for the following northeastern States: Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. The Energy Information Administration (EIA) is conducting this mandatory survey under the general information gathering provisions provided under the Federal Energy Administration Act of 1974, P.L. 93-275.

II. WHO MUST REPORT

Selected local distribution companies (LDC's) and pipelines that delivered natural gas to consumers during December 1999, and January and February 2000 in the northeastern United States as listed in Part I above.

III. WHEN TO REPORT

Completed Forms EIA-903 "Natural Gas Service Interruptions in the Northeast during December 1999, and January and February 2000" are to be filed with the EIA postmarked on or before May 22, 2000.

IV. WHERE TO REPORT

Each respondent is required to submit the completed form in any of the following formats:

- an Excel spreadsheet,
- a WordPerfect file, or
- paper copy

To: Energy Information Administration: EI-44
Mail Station: BE-064 FORSTL
U.S. Department of Energy
Washington, D.C. 20585-0644
Attn: Form EIA-903

or

Fax completed form to (202) 586-4420
Attn: Form EIA-903

or

E-mail the completed form to either:
mary.carlson@eia.doe.gov or
barbara.marinervolpe@eia.doe.gov

For general information and/or assistance call either Mary Carlson at (202) 586-4749 or Barbara Mariner-Volpe at (202) 586-5878. Ms. Carlson and Ms. Mariner-Volpe can be contacted by e-mail at the addresses listed above.

V. PROVISIONS FOR CONFIDENTIALITY OF INFORMATION

Information supplied in response to this form will be kept confidential by the Energy Information Administration as follows. The Office of Legal Counsel of the Department of Justice concluded on March 20, 1991, that the Federal Energy Administration Act requires the EIA to provide company-specific data to the Department of Justice, or to any other Federal agency when requested for official use, which may include enforcement of Federal law.

The information contained on this form may also be made available, upon request, to another component of the Department of Energy (DOE), to any Committee of Congress, the General Accounting Office or other Congressional agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order.

GENERAL DESCRIPTION OF THE FORM

The Form EIA-903 "Natural Gas Service Interruptions in the Northeast during December 1999, and January and February 2000" is divided into six parts. All selected respondents are required to submit the form and must complete all data items applicable to the company's operations in the report State(s).

INSTRUCTIONS

General Instructions

If final numbers are not available for the information requested, estimated data are acceptable. Indicate with an "E" any estimated data element.

Computer files or other listings may be submitted in lieu of designated parts of the form.

The form may be copied as necessary to cover all rate schedules or contract categories. Computer files or other listings may be submitted in lieu of completing designated items. The form Part number should be written on any computer listing.

Part I. Identification and Certification

Requests the name, address, telephone number, and e-mail address of the person to be contacted with any questions regarding the submission.

The contact should be an individual who is familiar with the service arrangements of the responding company and its customers.

Part I also asks the responding company to indicate the units it will use for reporting, i.e., thousand cubic feet (Mcf) or dekatherms (Dth).

Part II. Interruptible Natural Gas Service Tariffs or Contract Categories

A. *Description of Interruptible Natural Gas Service Tariffs or Contract Categories.* Requests information on selected characteristics of interruptible service arrangements provided to end-use customers. This category should include any tariff or contract category that allows service to be interrupted at some time during the contract/tariff period. For example, if the annual service agreement is for 330 days of firm service and up to 35 days of a lower level of firm service or interruptible service, that type of service agreement should be categorized as interruptible for purposes of this survey.

Note: Copies of relevant parts of tariff schedules or contract categories are acceptable in lieu of the form.

B. Natural Gas Service Interruptions or Service Restrictions Under Interruptible Tariffs During the Period from December 1, 1999, to February 29, 2000. Requests information by rate schedule or contract category listed in Part II (A) for any natural gas service that was interrupted during the period from December 1, 1999, to February 29, 2000.

Part III. Customers with Interruptible Natural Gas Service Interrupted during January and February 2000

Requests the names and contact information for customers with interruptible service agreements who were interrupted. Please list a sufficient number of companies to provide at least 75% of the total volume that was interrupted under all schedules up to a total of 50 companies in the report State. If possible, please list customers in order from largest to smallest volumes interrupted.

The customer contact listed should be an individual who is familiar with the service arrangements and the company practices regarding back-up fuel inventories and purchasing practices.

Part IV. Firm Natural Gas Service Tariffs or Contract Categories

Requests baseline monthly and weekly information for those categories of service which were interrupted during December 1999 and January and February 2000. (See definition of firm service.)

Part V. Customers with Firm Natural Gas Service Interrupted during January and February 2000

Requests the names and contact information for customers with firm service agreements who were interrupted. Please list a sufficient number of companies to provide at least 75% of the total volume that was interrupted under all schedules up to a total of 50 companies in the report State. If possible, please list customers in order from largest to smallest volumes interrupted.

The information requested in this form will be kept confidential and not disclosed to the public to the extent that it satisfies the criteria for exemption in the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905.

Upon receipt of a request for this information under the FOIA, the DOE shall make a final determination whether the information is exempt from disclosure in accordance with the procedures and criteria provided in the regulations. To assist us in this determination, respondents should demonstrate to the DOE that, for example, their information contains trade secrets or commercial or financial information whose release would be likely to cause substantial harm to their company's competitive position. A letter accompanying the submission that explains (on an element-by-element basis) the reasons why the information would be likely to cause the respondent substantial competitive harm if released to the public would aid in this determination.

VI. SANCTIONS

The timely, comprehensive, and accurate submission of this form by those required to report is mandatory under §13(b) of the Federal Energy Administration Act of 1974 (FEA Act) P.L. 93-275.

VII. DEFINITIONS

Firm Service Tariffs or Contracts: Any tariff, contract, or other type of service arrangement under which the respondent agreed to provide firm continuous service without any provision for interruptions or a break in service during the contract period.

Interruptible Service Tariffs or Contract Categories: For purposes of this request, interruptible service includes any tariff, contract, or other type of service arrangement under which the responding company agreed to provide service but might discontinue the service upon some agreed upon conditions. This category would include service arrangements such as the following:

- service that is interrupted when the temperature drops to or below a specified level.
- contracts for firm service for much of the year but with a provision for being interrupted under certain conditions or during certain time periods. For example, if the service agreement is for 330 days of firm service and up to 35 days of a lower level of firm service or interruptible service, that type of service agreement should be categorized as interruptible for purposes of this survey.
- service is interrupted on a specific date or schedule.

Maximum Daily Quantity (MDQ): The maximum amount of gas the transporter is obligated to deliver during any single day and for which the customer agrees to pay a fee. An MDQ may be specified in a tariff or contract service agreement. The MDQ is sometimes referred to as maximum daily contract quantity.

Northeastern United States: For the purposes of this survey, includes Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

The customer contact person should be an individual who is familiar with the service arrangements and the company practices regarding back-up fuel inventories and purchasing practices.

Part VI. Customers that Declined Service during January and February 2000

Requests the names and contact information for customers that declined natural gas service when interruptions were ended and natural gas service was offered/available in the report State. The customer contact should be an individual who is familiar with the service arrangements and company practices regarding back-up fuel inventories and purchasing practices.

EIA-903

Form Approved
OMB No. 1905-0199
Expires: 09/30/2000

U.S. DEPARTMENT OF ENERGY
Energy Information Administration
Washington, D.C. 20585

FORM EIA-903
NATURAL GAS SERVICE INTERRUPTIONS IN THE NORTHEAST DURING DECEMBER 1999, AND JANUARY AND FEBRUARY 2000

This report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275.) For the provisions concerning the confidentiality of information and sanctions, see Sections V and VI of the instructions.		
PART I. Identification and Certification		
1. Company Name:		
2. Service in (State):	3. Address (Street, City, State, Zip Code)	
4. Contact Person:	5. Title:	
6. Telephone Number:	7. E-Mail Address:	8. Fax Number:
9. Signature:	10. Date:	

Important: Volumetric data filed on this Form are reported in (check one) : ☐ Mcf (thousand cubic feet) ☐ Dth (dekatherms)
Heat content: ____________Btu/cf.

DOE006-0071

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EIA-903

Company Name ______________________

State ______________________

PART II. Interruptible Natural Gas Service Tariffs or Contract Categories

A. Description of Interruptible Natural Gas Service Tariffs or Contract Categories

Please provide the following information for each tariff schedule that allows service to be interrupted to an end-user. Any tariff or contract that allows service to be interrupted at some time during the contract/tariff period of service should be included. For example, if the annual service agreement is for 330 days of firm service and up to 35 days of a lower level of firm service or interruptible service, that type of service agreement should be categorized as interruptible for purposes of this survey.

Rate Schedule and Name of Interruptible Service ______________________ *Note: For each rate schedule or contract category, your company must file information on Part II (B).*
Describe the conditions under which the service is interrupted: (A copy of the relevant portion of the tariff schedule or contract category may be attached in lieu of completing this Section. The rate schedule or contract category should be noted on the copy.)
Describe any requirements contained in the tariff or contract for fuel back-up arrangements by the customer. (A copy of the relevant portion of the tariff schedule or contract category may be attached in lieu of completing this Section. The rate schedule or contract category should be noted on the copy.)

Please make additional copies of the form as necessary to cover each rate schedule or contract category.

DOE006-0072

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EIA-903

Company Name ______________________

State ______________________

PART II. Interruptible Natural Gas Service Tariffs or Contract Categories (continued)

B. Natural Gas Service Interruptions or Service Restrictions Under Interruptible Tariffs During the Period from December 1, 1999, to February 29, 2000

Please provide the following information *by tariff schedule or contract category listed in Part II (A)* above for any natural gas service that was interrupted during the period from December 1, 1999, to February 29, 2000. Provide the information for the report State in which your company made deliveries. Indicate with an "E" any information which is estimated.

Rate Schedule and Name of Interrupted Service	Monthly Data			Weekly Data									
______________________	Dec 1999	Jan 2000	Feb 2000	1/2-1/8	1/9-1/15	1/16-1/22	1/23-1/29	1/30-2/5	2/6-2/12	2/13-2/19	2/20-2/26	2/27-2/29
Cumulative maximum daily quantity of gas to be provided under these contracts in each period. *(e.g., If the maximum daily quantity (MDQ) for each day during February 2000 is 150 units, then the cumulative MDQ for February 2000 is 150 units/day x 29 days = 4,350 units.)*												
Total deliveries interrupted in each period. *(e.g., If 100 units were interrupted for each of three days, the total interrupted deliveries would be 300 units.)*												
Number of days interrupted under these contracts in each period. *(If contract was interrupted for less than a day, provide the fractional day equivalent.)*												
Number of days of service with flow restrictions to customers in each period. *(Service was not interrupted.)*												

Please make additional copies of the form as necessary to cover each rate schedule or contract category.

DOE006-0073

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EIA-903

Company Name ____________________
State ____________________

PART III. Customers with Interruptible Natural Gas Service Interrupted during January and February 2000

Customer list should account for at least 75 percent of the total volume of interruptible service that was interrupted under all schedules, up to a total of 50 companies in the State specified. If possible, please list customers in order from largest to smallest volumes interrupted. The customer contact should be an individual who is familiar with the service arrangements and the company practices regarding back-up fuel inventories and purchasing practices. You may use the following format or you may attach the information using a computer file or other listing.

Customer Name (company address, if available)	Volume Interrupted (total all schedules)	Types of Alternative Fuel Capability (if known)	Customer Contact Person	Telephone Number (include e-mail address if available)

Please make additional copies of this form as necessary to complete the filing.

EIA-903

Company Name ______________________
State ______________________

Part IV. Firm Natural Gas Service Tariffs or Contract Categories

A. During the period from December 1, 1999 through February 29, 2000, did you curtail, suspend, or restrict service to any customer(s) with firm service tariffs or contracts in the State specified?
Check one: Yes No

B. If the answer to A was "No," please provide the monthly total of the maximum daily quantities of gas to all end-use customers with firm service for the following months (e.g., *if the maximum daily quantity (MDQ) for each day during February 2000 is 150 units, then the cumulative MDQ for February 2000 is 150 units/day x 29 days = 4,350 units):*

December 1999 ______________________
January 2000 ______________________
February 2000 ______________________

C. *If the answer to A was "No," please turn to Part VI, and complete as appropriate.*

D. If the answer to A was "Yes," provide the following information for the total of all firm natural gas service tariffs or contract categories for the report State in which you had deliveries. Indicate with an "E" any information which is estimated.

	Monthly Data			Weekly Data								
	Dec 1999	Jan 2000	Feb 2000	1/2-1/8	1/9-1/15	1/16-1/22	1/23-1/29	1/30-2/5	2/6-2/12	2/13-2/19	2/20-2/26	2/27-2/29
Cumulative maximum daily quantity of gas to be provided under these contracts in each period. *(e.g., If the maximum daily quantity (MDQ) for each day during February 2000 is 150 units, then the cumulative MDQ for February 2000 is 150 units/day x 29 days = 4,350 units.)*												
Total deliveries interrupted in each period.												
Number of days interrupted under these contracts in each period. *(If contract was interrupted for less than a day, provide the fractional day equivalent.)*												
Number of days of service with flow restrictions to customers in each period. *(Service was not interrupted.)*												

Please make additional copies of the form as necessary to complete the filing.

DOE006-0075

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EIA-903

Company Name ______________________
State ______________________

Part V. Customers with Firm Natural Gas Service Interrupted during January and February 2000

Customer list should account for at least 75 percent of the total volume of firm service which was interrupted, up to a total of 50 companies in the State specified. If possible, please list customers in order from largest to smallest volumes interrupted. The customer contact should be an individual who is familiar with the service arrangements and the company practices regarding back-up fuel inventories and purchasing practices. You may use the following format or you may attach the information using a computer file or other listing.

Customer Name (company address, if available)	Volume Interrupted (total all schedules)	Types of Alternative Fuel Capability (if known)	Customer Contact Person	Telephone Number (include e-mail address, if known)

Please make additional copies of the form as necessary to complete the filing.

EIA-903

Company Name ______________________

State ______________________

Part VI. Customers that Declined Service during January and February 2000

Please provide a list of the customer name, contact person and telephone number for companies that declined natural gas service when interruptions were ended and natural gas service was offered/available in the State specified. The customer contact should be an individual who is familiar with the service arrangements and the company practices regarding back-up fuel inventories and purchasing practices. You may use the following format or you may attach the information using a computer file or other listing.

Customer Name (company address, if available)	Customer Contact Person	Telephone Number (include e-mail address, if known)

Please make additional copies of the form as necessary to complete the filing.

Form EIA-904

Customer Survey of Natural Gas Service Interruptions in the Northeast During January and February 2000

U.S. DEPARTMENT OF ENERGY Energy Information Administration Washington, D.C. 20585	**CUSTOMER SURVEY OF NATURAL GAS SERVICE INTERRUPTIONS IN THE NORTHEAST DURING JANUARY AND FEBRUARY 2000**

LABEL
Company name
Control ID
State

1. The timely, comprehensive, and accurate submission of this form by those required to report is mandatory under §13(b) of the Federal Energy Administration Act of 1974 (FEA Act) P.L. 93-275.

2. Those required to report are selected users of natural gas located in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont whose supply of natural gas was interrupted during December 1999, or January or February 2000.

3. This completed form should be filed by June 16, 2000.

4. Data may be submitted directly on this form or in any other format, such as:

   Excel spreadsheet
   Word or WordPerfect file

   Whatever format is used to report, ensure that answers are provided for all pertinent questions.

5. For general information and/or assistance call Ms. Dawn Thomas toll free at 1-800-937-8281 extension 2065.

6. Mail the completed form to:
   Natural Gas Interruptions
   c/o Westat
   1650 Research Blvd.
   Rockville, MD 20850
   or
   Fax the completed form to:
   301-315-5934
   Attn: Natural Gas Interruptions
   or
   E-mail the completed form to:
   thomasd1@westat.com

Form EIA-904
Form Approved
OMB No. 1905-0200
Expires 08/31/2000

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DOE006-0079

PROVISIONS FOR CONFIDENTIALITY OF INFORMATION

Information supplied in response to this form will be kept confidential by the Energy Information Administration as follows. The Office of Legal Counsel of the Department of Justice concluded on March 20, 1991, that the Federal Energy Administration Act requires the EIA to provide company-specific data to the Department of Justice, or to any other Federal agency when requested for official use, which may include enforcement of Federal law.

The information contained on this form may also be made available, upon request, to another component of the Department of Energy (DOE), to any Committee of Congress, the General Accounting Office or other Congressional agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order.

The information requested in this form will be kept confidential and not disclosed to the public to the extent that it satisfies the criteria for exemption in the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905.

Upon receipt of a request for this information under the FOIA, the DOE shall make a final determination whether the information is exempt from disclosure in accordance with the procedures and criteria provided in the regulations. To assist us in this determination, respondents should demonstrate to the DOE that, for example, their information contains trade secrets or commercial or financial information whose release would be likely to cause substantial harm to their company's competitive position. A letter accompanying the submission that explains (on an element-by-element basis) the reasons why the information would be likely to cause the respondent substantial competitive harm if released to the public would aid in this determination.

Public Reporting Burden for this collection of information is estimated to average 6 hours per response, including the time of reviewing instructions, searching existing data records, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Statistics and Methods Group, EI-70, Washington, DC 20585-0670, and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

All selected respondents are required to submit the form and must complete all data items applicable to the company's operations.

Part I: Identification

Please print. The contact person should be an individual who is familiar with the fuel service arrangements.

1. Name of company if different from front page: ______________________
2. Address of contact person (Street, city, state, zip code): ______________________

   ____

   ____
3. Name of contact person: ______________________
4. Title: ______________________
5. Telephone no.: ______________ Fax number: ______________
6. E-mail address: ______________________
7. Signature: ______________ Date: ______________

Part II: General Information

1. Did you experience an interruption in service of natural gas during January or February 2000?	☐ Yes ☐ No (No further information is required. Please return the form as instructed on the front page.)
2. When gas supplies were unavailable, did you use alternative fuels in place of natural gas for your operations?	☐ Yes ☐ No (No further information is required. Please return the form as instructed on the front page.)
3. Please indicate which of the following fuels were used to substitute for natural gas that was interrupted during January or February 2000. (Check each fuel used.)	☐ Distillate fuel oil ☐ Propane (LPG) ☐ Kerosene & Turbine Fuels ☐ Residual Fuel Oils ☐ Electricity ☐ Natural gas (from alternate supplier) ☐ Other, please specify:
4. In general, during January and February, what is the maximum percentage of your natural gas needs that can be offset with distillate fuel oil?	__________%

Only data for selected heating season months for 1998 and 1999 and for selected weeks for 2000 are being requested. If final numbers are not available for the information requested, estimated data are acceptable. Indicate with an "E" any estimated data element.

Part III. Natural Gas Deliveries and other Energy Purchases in Period

Record monthly natural gas deliveries for the 3 months requested. Provide weekly data for the 9 weeks ending on the dates listed. Record any liquid fuel purchases for the same periods.

Report total volumes for the period. Indicate the units used for reporting, e.g., thousand cubic feet (Mcf) or dekatherms (Dth).

Interruptible Contract: For purposes of this request, interruptible service includes any contract, tariff, or other type of service arrangement where the energy supplier agreed to provide service but might discontinue the service upon some agreed upon conditions.

Firm Contract: Any contract, tariff, or other type of service arrangement under which the energy supplier agreed to provide firm continuous service without any provision for interruptions during the contract period.

Part IIIA. Natural Gas Deliveries in Period

	Interruptible Contract			Firm Contract	Other
	Days Interrupted	Volume Interrupted	Volume delivered	Volume delivered	Volume delivered
Units used for reporting:		Units:	Units:	Units:	Units:
Monthly data					
Dec. 1998					
Jan. 1999					
Dec. 1999					
Year 2000 week ending					
Jan. 8					
Jan.15					
Jan. 22					
Jan. 29					
Feb. 5					
Feb. 12					
Feb. 19					
Feb. 26					
Mar. 4					

Part IIIB. Liquid Fuel Purchases in Period

	Distillate	Propane (LPG)	Kerosene & Turbine Fuels	Residual Fuel Oils
Units used for reporting:	Units:	Units:	Units:	Units:
Monthly data				
Dec. 1998				
Jan. 1999				
Dec. 1999				
Year 2000 week ending				
Jan. 8				
Jan. 15				
Jan. 22				
Jan. 29				
Feb. 5				
Feb. 12				
Feb. 19				
Feb. 26				
Mar. 4				

Part IV. Means of Delivery for Purchases of Liquid Fuels

How were deliveries made to the final point of consumption?	Truck	Barge	Pipeline	Other (specify)
Distillate	☐	☐	☐	☐ ________
Propane (LPG)	☐	☐	☐	☐ ________
Kerosene & Turbine Fuels	☐	☐	☐	☐ ________
Residual Fuel Oils	☐	☐	☐	☐ ________

Part V: Distillate Purchases to Offset Natural Gas
Report total volume for the period.

	Units	Weekly Data for Year 2000								
		1/8	1/15	1/22	1/29	2/5	2/12	2/19	2/26	3/4
Distillate										

Part VI: Liquid Fuels Consumed in Period
Report total volume for the period.

	Distillate	Propane (LPG)	Kerosene & Turbine Fuels	Residual Fuel Oils
Units used for reporting:	Units:	Units:	Units:	Units:
Monthly data				
Nov. 1998				
Dec. 1998				
Jan. 1999				
Nov. 1999				
Dec. 1999				
Year 2000 week ending				
Jan. 8				
Jan. 15				
Jan. 22				
Jan. 29				
Feb. 5				
Feb. 12				
Feb. 19				
Feb. 26				
Mar. 4				

Part VII: On-Site Fuel Storage Capacity and Inventories

Part VIIA: On-Site Distillate Storage Capacity

Report as of end of period.

	Units	Monthly Data					
		Nov. 1998	Dec. 1998	Jan. 1999	Dec. 1999	Jan. 2000	Feb. 2000
Distillate							

Part VIIB: On-Site Inventories of Liquid Fuels

Report end of period stocks.

	Distillate	Propane (LPG)	Kerosene & Turbine Fuels	Residual Fuel Oils
Units used for reporting:	Units:	Units:	Units:	Units:
Monthly data				
Dec. 1998				
Jan. 1999				
Nov. 1999				
Dec. 1999				
Year 2000 week ending				
Jan. 8				
Jan.15				
Jan. 22				
Jan. 29				
Feb. 5				
Feb. 12				
Feb. 19				
Feb. 26				
Mar. 4				

DOE006-0085

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Thank you for completing this report.

Please return the completed report to:

Natural Gas Interruptions
c/o Westat
1650 Research Boulevard
Rockville, MD 20850

Appendix D

State Heating Oil Studies

Appendix D

State Heating Oil Studies

The New York State Energy Research and Development Authority (NYSERDA), the Rhode Island Department of Attorney General, and the New Jersey Board of Public Utilities have investigated the cause of the distillate fuel price surge and supply shortfall that occurred during January and February 2000.

NYSERDA estimated that peak-shaving electric generation facilities in the State of New York consumed approximately 4.3 million gallons (102,380 barrels) of distillate fuel oil during January 2000, and independent power producers (IPPs) that switched from natural gas to distillate consumed approximately 7.8 million gallons (185,714 barrels). The majority of distillate fuel oil for the month of January 2000 occurred in the last two weeks of the month. For the peak shaving facilities, these estimates include both those facilities that use distillate fuel oil on a regular basis and those facilities that use distillate as a replacement fuel during a natural gas interruption.

As a result of these findings, the New York Public Service Commission passed an order requiring certain interruptible natural gas customers to maintain a minimum inventory of their alternative fuel during the winter heating season. However, some service agreements specify that interruptible gas customers keep an adequate backup supply and maintain the dual-fuel equipment necessary to utilize the fuel. The rule as proposed, requires 10 days storage supply of their alternative fuel, if that fuel is distillate fuel oil or if the customer serves human need end users. In addition, NYSERDA advocates holding a pre-winter meeting between state and federal representatives and petroleum industry representatives. Other initiatives addressed in the NYSERDA report involve the cooperation of state, federal and industry representatives in order to mitigate the effects of a supply disruption or price spike in the distillate fuel oil market.

In contrast to the large volume of incremental demand generated in New York by the electric generation sector, the Rhode Island Department of Attorney General estimated that total fuel oil consumption by all interruptible customers in both the industrial and electric generation sector for the January-February 2000 period was 1.1 million gallons (26,190 barrels) of distillate fuel oil. Because Rhode Island has a smaller market than New York, the total interruptible end-use consumption during both January and February 2000 was low. The relatively small volume consumed could be a result of changing fuel use by interruptible users. According to the Rhode Island study, it is becoming more common for electric utilities to have access to firm service supplies of natural gas as their alternative during an interruption in service, rather than using distillate fuel oil from storage or purchasing fuel on the spot market. The report found that "Although the interruptions matched the timing of the largest increases in the #2 distillate fuel oil prices, the volumes of fuel oil used by interruptible consumers did not have a major impact on fuel oil suppliers." [Page 27]

The findings in Rhode Island resulted in different policy recommendations than in New York. The development of a regular publication concerning a distillate (No.2) fuel oil inventory index for consumers and advance information about winter fuel supply is the main focus. Other recommendations include inventory supply standards that would require fuel oil suppliers to demonstrate their ability to meet customers' demands under forecasted winter demands and have sufficient inventories entering the heating season. Regulatory options requiring minimum inventories for end-users and economic incentives for operators to discourage "just-in-time" inventory practices are also viable options presented in the Rhode Island study.

New Jersey has implemented statewide rules regarding minimum supply of backup fuels for interruptible customers who use No. 2 distillate fuel oil, No. 4 fuel oil, jet fuel, or kerosene, and a noncompliance penalty of 10 times their prevailing tariff rate for interruptible customers who burn gas during the interruption. New Jersey requires a 7-day supply either through onsite storage or through a firm contractual agreement if the customer plans to continue operating during a gas interruption. This order took effect November 1, 2000, the start of the natural gas heating season. Wholesale electric generators, including cogeneration customers with wholesale electric contracts, are exempt. The stated intent of the order is to ensure that interruptible customers comply with system interruption notices so that all firm customers will receive reliable service.

January 2001

Overview

This month's Outlook incorporates our first set of projections through 2002. Key assumptions include: a soft landing for the U.S. economy in 2001 and solid growth in 2002; generally declining oil and gas prices, although price levels remain relatively high by historical standards; solid growth in natural gas demand (partly related to weather this year but fundamentally tied to increases in demand from the electric generation sector from spring 2001 on); and a return to approximately normal growth in petroleum demand in the United States for 2001 and 2002 as prices abate and transportation requirements continue to grow.

Since the end of November, crude oil prices have fallen sharply (the average price for West Texas Intermediate was $34.30 per barrel in November and $28.40 in December). Our analysis of industrialized country stocks suggests that additional weakening in the price through 2001 should be limited, especially given the likelihood of a significant output cut by OPEC before the winter is done. Indeed, some intermediate increases from the average December level are likely, in our view. Still, we see average annual prices declining by about $1.00-$1.50 per barrel in 2001 and by perhaps $5 per barrel in 2002.

Despite scaling back the extent of expected heating oil price rises this winter, we conclude that typical homes heating with oil will pay about 40 percent more for oil heat this winter than last year, which is another upward revision in the estimate (Figure 1). Somewhat lower average prices are being offset by higher demand (particularly in November and December, both of which exhibited about 28 percent more heating degree-days in the Northeast in 2000 than they did in 1999). While prices have eased some in recent weeks, the heating oil market is still relatively tight and subject to significant volatility. Still, it is worth noting that, despite very cold temperatures over the last 2 months, the heating oil market has held up rather well.

The natural gas market has served up sharply higher prices since last month, generating significant upward adjustments in our average winter gas price projections. Very large increases in heating-related demand appear to have materialized in November and December, resulting in a sharp reduction of gas available in storage to well below the previous low recorded by EIA. (The end-December 2000 estimated working gas storage level is approximately 10 percent below the previous low seen since 1973 which occurred in 1976). Continued strong demand (from normal weather) this winter would keep gas stocks at minimal levels for the remainder of the heating season and ensure

Figure 1. Consumer Winter Heating Oil Costs

Average Northeast Household Heating With Oil

	97-98 Actual	98-99 Actual	99-00 Actual	00-01 Base Fcst.
Gal	636	650	644	717
$/gal	$0.92	$0.80	$1.18	$1.48
Cost ($)	$585	$520	$760	$1,061

Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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strong injection-season demand next spring and summer. We see average gas wellhead prices as averaging about $5.20 per thousand cubic feet (mcf) in 2001 (compared to an estimated $3.70 in 2000) and about $4.50 per mcf in 2002.

We have raised our estimates of increased heating expenses for residential consumers who heat with natural gas to approximately 70 percent above 1999-2000 levels for the current heating season (Figure 2). Our previous estimate was between 50 and 55 percent. Much higher estimated demand (particularly due to the cold weather in November and December) as well as somewhat higher residential prices combined to generate the higher estimates. The expected 45-percent increase in the nominal average residential price would be the highest season-to-season growth rate since at least 1975.

International

Crude Oil Prices. We currently estimate that the monthly average U.S. imported crude oil price in December was $25.50 per barrel (about $28.40 for West Texas Intermediate crude oil), or about $6 per barrel lower than in November (Figure 3).

EIA had earlier expected that the tight oil stock situation in the OECD countries would continue to provide price support, and prevent prices from falling significantly until mid-2001. Recent price declines have indicated more weakness in the near-term market. However, EIA believes that the OPEC basket oil price (roughly equivalent to the average U.S. imported crude oil price) will remain well within (and probably toward the higher end of) OPEC's target range of $22 - $28 per barrel in 2001, particularly if OPEC institutes significant cuts in oil production in the early part of 2001. In fact, we believe that some near term price increases may appear until the extent of any OPEC cuts is sorted out. EIA then projects that oil prices will decline in 2002 toward the lower end of the target range as industrialized country oil stocks move closer to normal levels.

International Oil Supply. OPEC members have suggested that an agreement in principle has been reached to reduce production quotas at its January 17 meeting. EIA's assumes that as a result of this agreement, actual OPEC 10 production levels will decline by about 1 million barrels per day from December levels by spring, with half of this decline coming from Saudi Arabia. With this assumed decline, OPEC 10 production is expected to return to roughly its July 2000 level. Although EIA had previously projected that OPEC would need to cut output to support prices, the larger cutbacks being discussed by OPEC have resulted in EIA's lowering its projection of OPEC production in 2001 by 500,000 barrels per day from the previous Outlook (Figure 4).

Iraqi efforts to end U.N. sanctions have resulted in falling exports and production over the past few weeks. These efforts are assumed to continue, and EIA has lowered its projections slightly for Iraqi exports and production in 2001.

Figure 2. Consumer Winter Natural Gas Costs

Average Midwest Household, U.S. Prices

	97-98 Actual	98-99 Actual	99-00 Actual	00-01 Base Fcst
Mcf	82.4	84.5	81.7	96.8
($/Mcf)	$6.56	$6.27	$6.61	$9.58
Cost ($)	$541	$530	$540	$927

Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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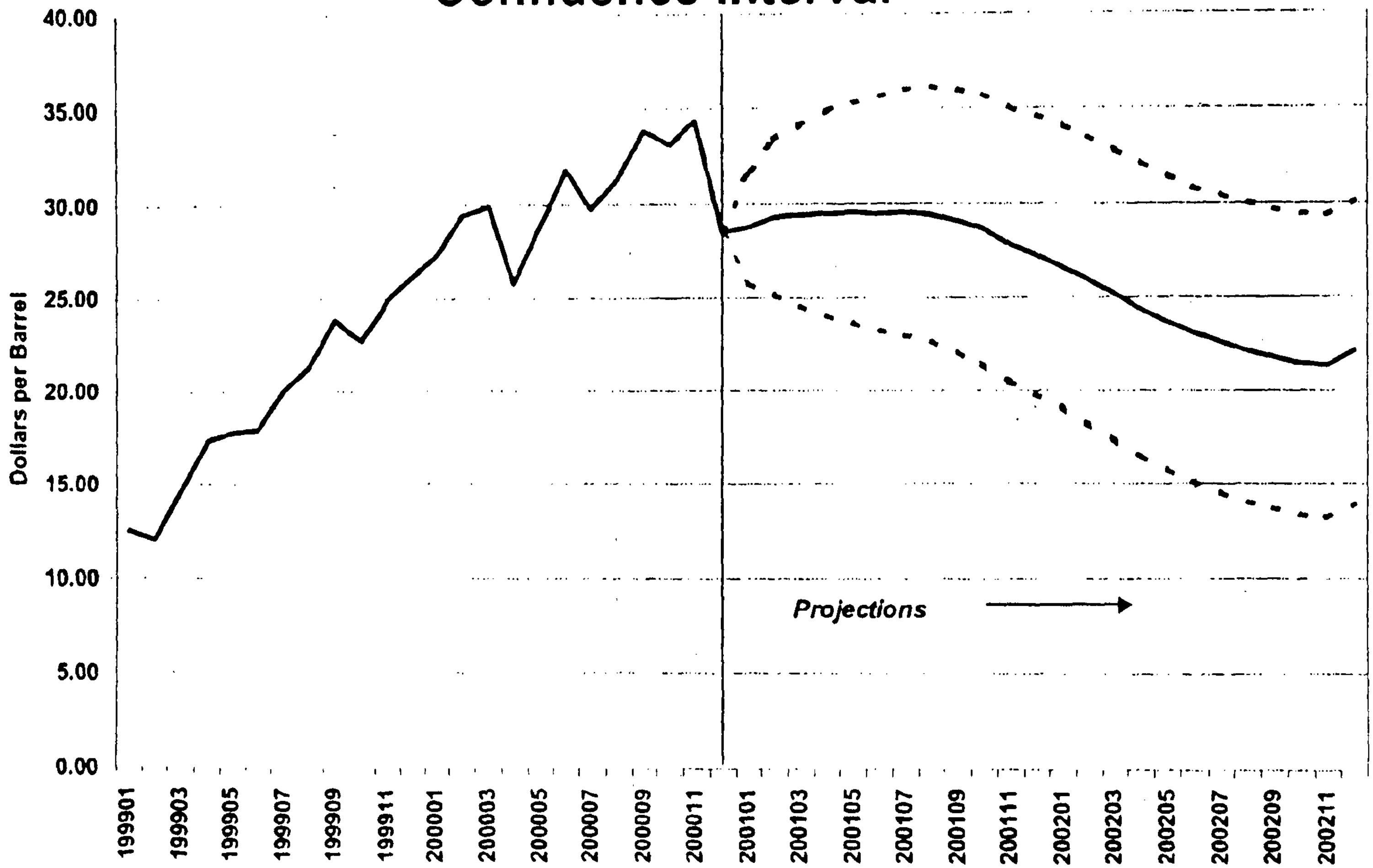
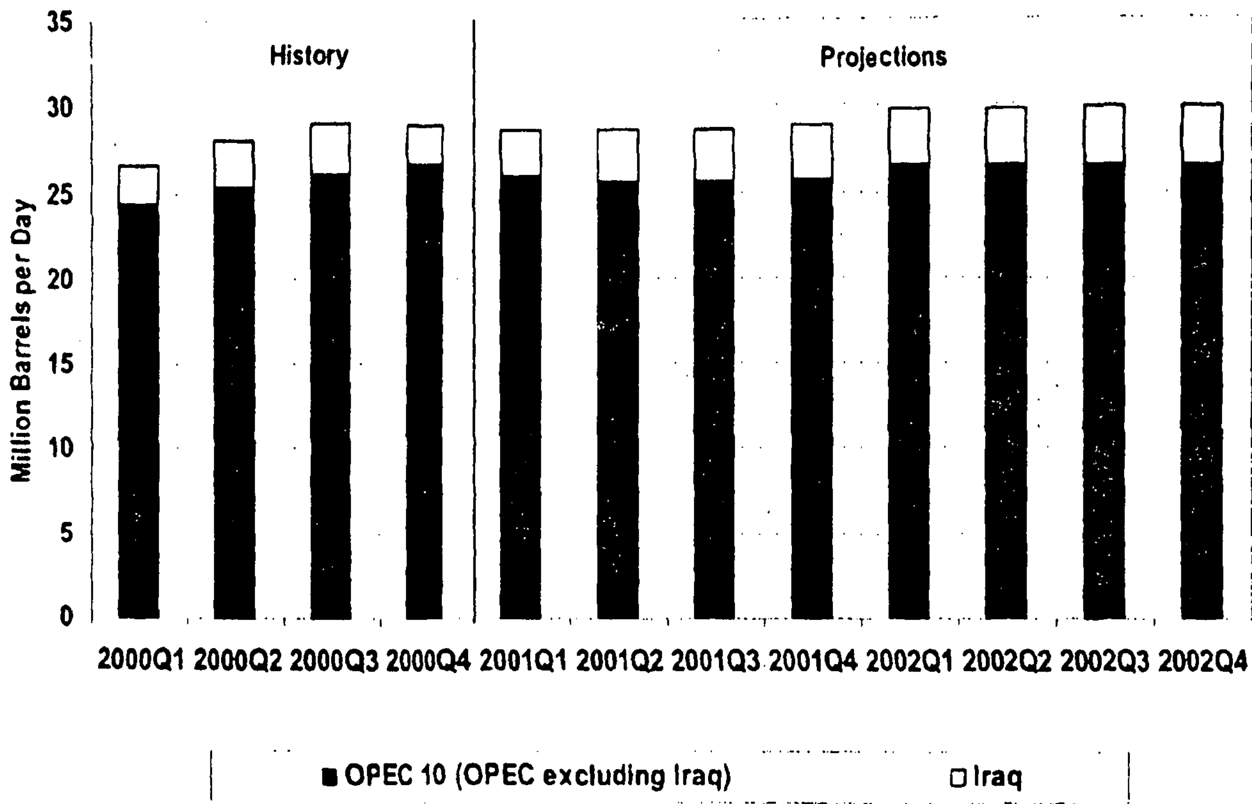
Figure 3. WTI Crude Oil Price: Base Case and 95% Confidence Interval



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

Figure 4. OPEC Crude Oil Production 2000-2002



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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Non-OPEC production is expected to increase by about 0.8 million barrels per day in 2001 and 2002 after posting an estimated increase of 1.2 million barrels per day in 2000. Between 40 percent and 50 percent of these increases are expected to come from the former Soviet Union, with smaller increases from other regions (Table 3). No further increases are expected from the North Sea as output from new fields is not expected to outstrip declines in maturing fields.

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). In part, this is due to the projected decline in world oil prices over the next 2 years. World oil demand growth in 2001 and 2002 is expected to be about 2 million barrels per day, similar to the growth that was seen in the 1995-1997 period. Non-OECD Asia is expected once again to be the leading region for oil demand growth this year, although near-term growth rates there are unlikely to match those seen in the early to mid 1990s.

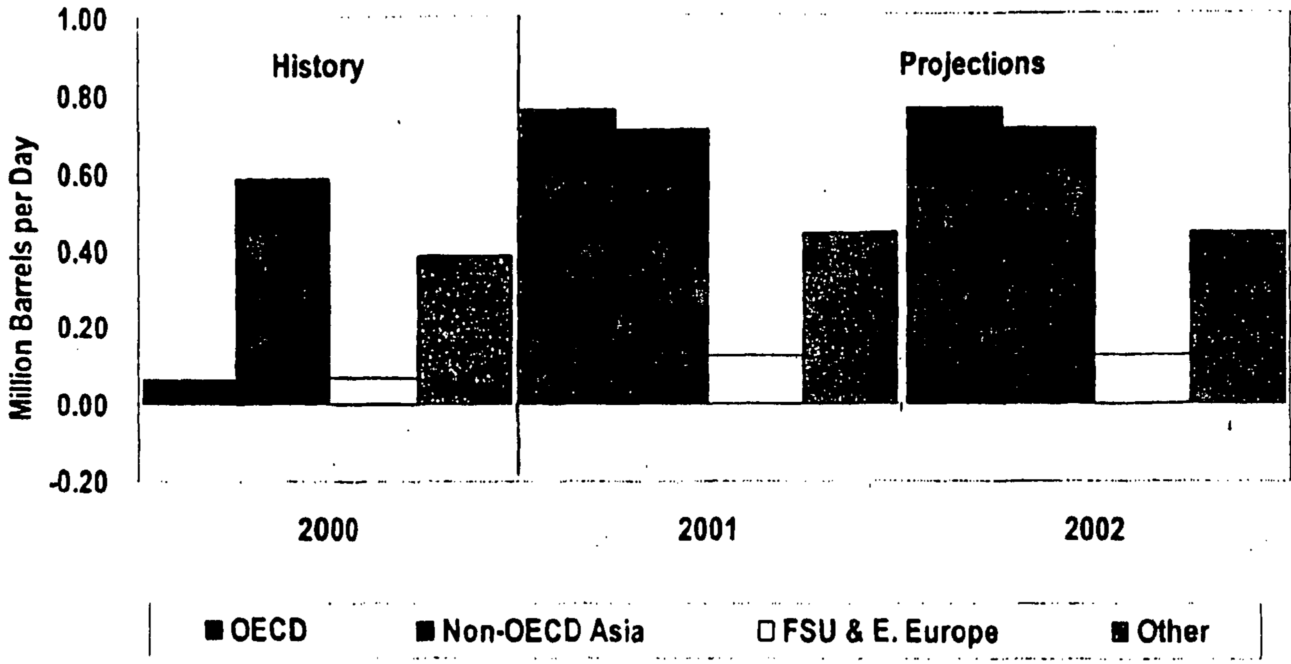
World Oil Inventories. EIA does not attempt to estimate oil inventory levels on a global basis; however, the direction global oil inventories are headed is discerned from EIA's world oil supply and demand estimates. These estimates provide only a rough guide because of what has come to be known as the "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 some of the oil that is counted as being produced worldwide simply becomes unaccounted for. As a result, EIA's estimated global inventory increases are likely overstated because they include an uncertain "missing barrels" component.

EIA estimates that total OECD oil stocks (including strategic reserves) reached 3,740 million barrels at the end of December 2000 (Figure 6). That represented a year-to-year increase of about 40 million barrels. More than all of that increase came from outside the United States, since total U.S. stocks declined by about 20 million barrels over the period. We have allowed for some strong increases in industrialized country stocks in 2001, such that normal levels may be reached by the beginning of 2002. That sort of development would seem to be required for world oil prices to move into the lower end of OPEC's target range for prices in 2002.

U. S. Energy Prices

Distillate Fuel (Heating Oil and Diesel Fuel). Particularly because crude oil prices have weakened since late November, but also because heating oil stock levels have not deteriorated recently despite very cold weather in the Northeast, our current estimate for average heating oil prices in the late fourth quarter of 2000 have been reduced. We now think that Q4 2000 heating oil prices probably averaged $1.45 per gallon, 6 cents lower than our previous estimate. We now anticipate winter average prices to be

Figure 5. Annual World Oil Demand
(Changes from Previous Year)



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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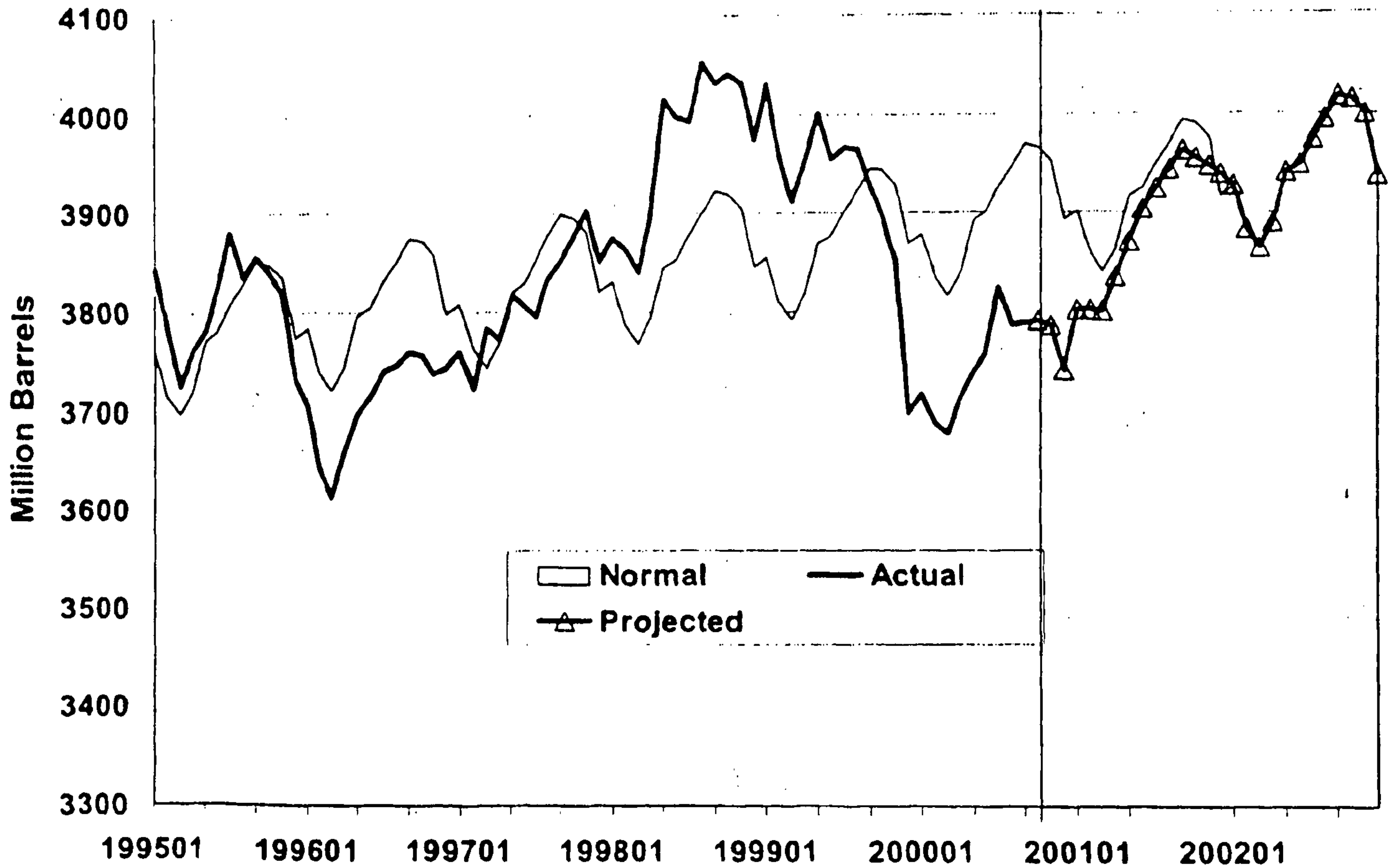
Figure 6. Total OECD Oil Stocks*



*Total includes commercial and government stocks

Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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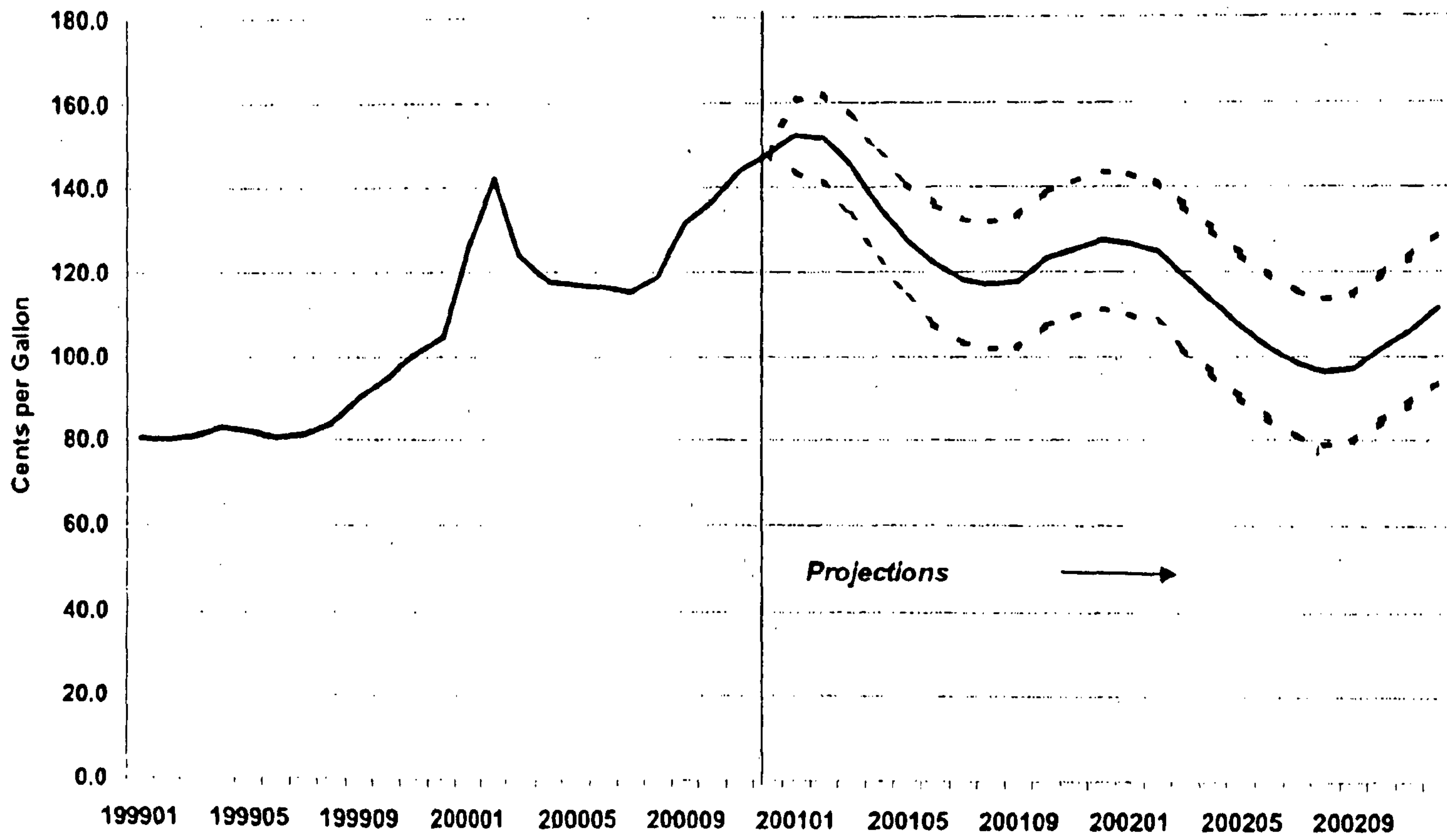
distributed around $1.48 compared to $1.52 in our previous Outlook. Despite this, retail heating oil prices, which averaged an estimated $1.48 per gallon this past December, were at the highest monthly levels recorded (in nominal terms). Prices have increased substantially since July, gaining 33 cents per gallon in 5 months (Figure 7). The national average price in December, was 44 cents per gallon above the December 1999 price. The considerably low level of inventories for distillate fuel, particularly heating oil, explains most of price rise. Given the currently low level of distillate stocks, a prolonged cold spell in the Northeast could lead to a repeat of last year's heating oil price spikes. Just recently, the monthly average spread of 80 cents per gallon between the December 2000 retail heating oil price and the crude oil (WTI) price exceeded the record 72 cents per gallon that occurred last February. At that time, a period of very cold weather in the Northeast, in combination with notably low stocks of distillate fuel, led to sharp spikes in heating oil and diesel fuel prices in New England and other areas in the region. (For the month of February 2000, the national average prices of heating oil and diesel fuel were $1.42 and $1.45 per gallon, respectively.) It should be noted that except for a period from late January through the first half of February, the winter in the Northeast (where 75 percent of the nation's heating oil is consumed) was actually warmer than normal.

Thus despite some bearish signs lately, a risk still exists this winter for further sharp price jumps similar to what happened last February, especially if the weather stays unusually cold in the Northeast. For the U.S., distillate stocks are currently about 21 million barrels below the low end of the normal range (Figure 8). The additional supplies of crude oil released from the Strategic Petroleum Reserve under an exchange program in late October of last year probably prevented the U.S. distillate supply situation from becoming even tighter than it is now.

Unless the remainder of the winter in the Northeast is unusually mild or world crude oil prices drop substantially, the projected high prices for heating oil and diesel fuel will continue until next spring. In December, crude oil prices did plunge significantly from the previous month, declining by $6.00 per barrel or about 14 cents per gallon. However, crude oil prices currently are showing some signs of heading back up. Nevertheless, the December drop in crude oil prices allowed retail heating oil prices to ease a bit. Assuming normal heating demand, with tight stocks and relatively high crude oil prices, we expect that winter residential heating oil prices will average $1.48 per gallon, or about 30 cents more per gallon compared to the last winter (Figure 1). We note that this average is about 4 cents per gallon below our winter average projections reported last month.

Motor Gasoline. Pump prices seem to have been heading back down. The retail price for regular unleaded motor gasoline fell an estimated 9 cents per gallon from October to December. Assuming that our crude oil price path holds, we project that retail motor

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



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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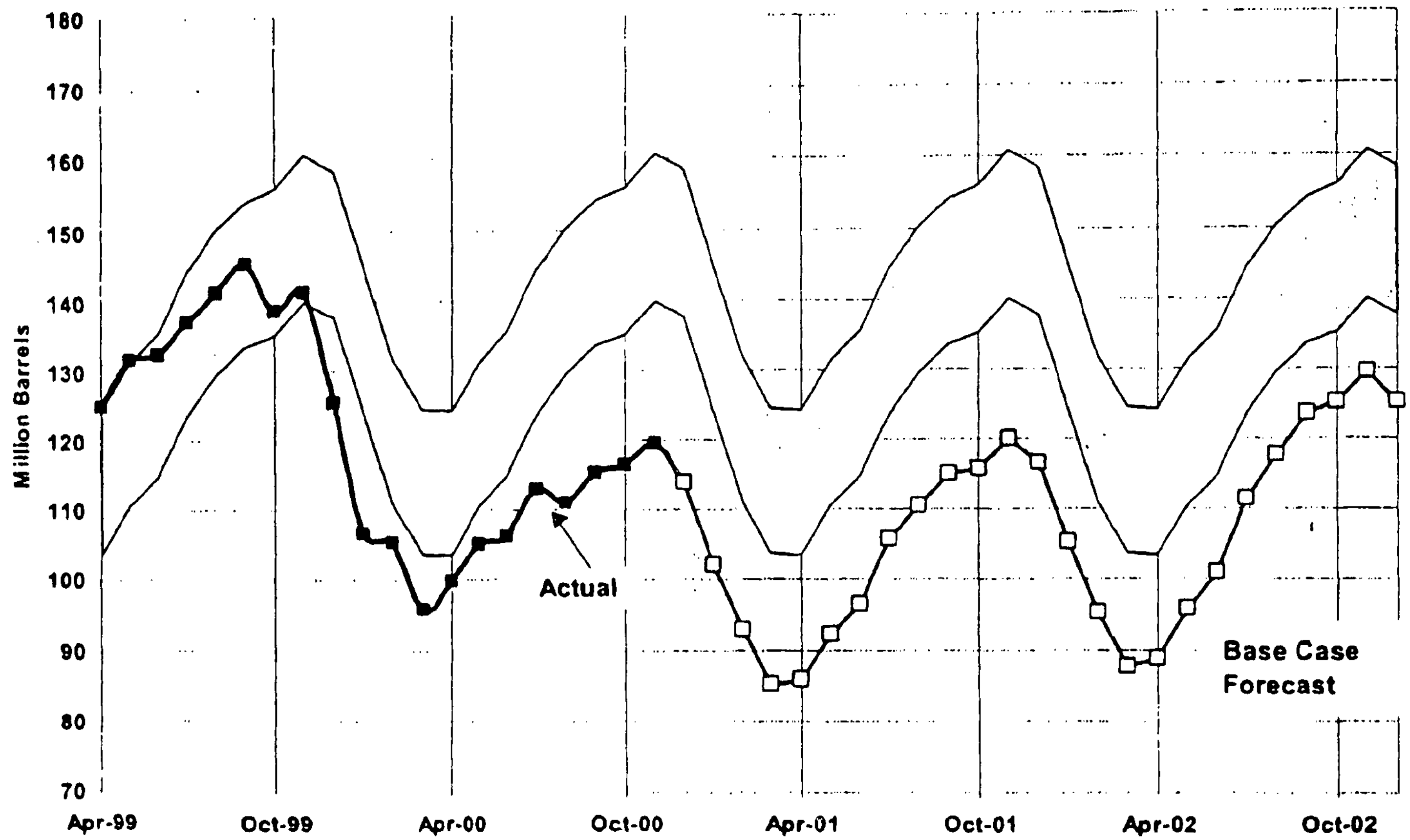
Figure 8. U.S. Total Distillate Fuel Stocks



NOTE: *Colored band is normal stock range*

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Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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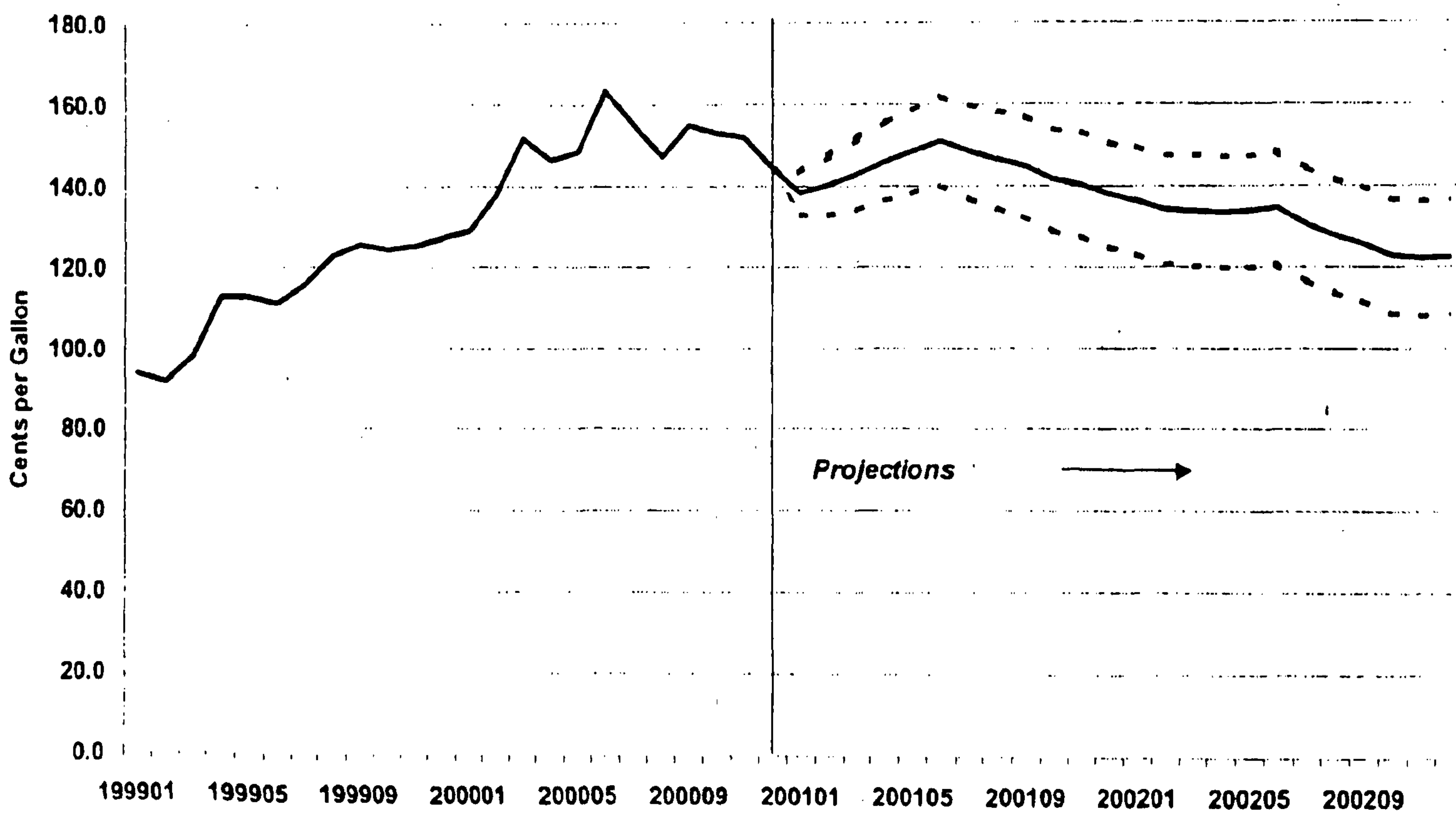
gasoline prices will decline an additional 6 cents this month, then rise modestly as the 2001 driving season begins in the spring. (Figure 9). For the summer of 2001, we expect little change from the average price of $1.50 per gallon seen during the previous driving season, as motor gasoline stocks going into the driving season are projected to be slightly less than they were last year (Figure 10). Such a development could set the stage for some regional imbalances in supply that could once again bring about significant price volatility in the U.S. gasoline market.

Natural Gas. Spot wellhead prices have shown some spectacular gains since the summer, averaging well over $4.00 per thousand cubic feet during a normally low-price season. For most of September through November, these prices have floated above $5.00 per thousand cubic feet, more than double the price of one year ago (Figure 11). For the month of December, the spot wellhead price averaged an unheard of $8.36 per thousand cubic feet. Never have spot gas prices at the wellhead been this high for such a sustained period of time. Although high oil prices have encouraged the current strength in gas prices, the predominant reason for these sustained high gas prices was, and still is, uneasiness about the winter supply situation. For much of the summer, low levels of underground storage raised concerns about the availability of winter supplies. Now that the winter has really started, the most severe assumptions about low storage levels have come true. The low levels of gas storage have put the spot market in an extremely volatile position. This was evident last month and early this month when short-term forecasts of colder weather resulted in one-day spot price jumps of $2.00 per thousand cubic feet. The spot wellhead price breached $10.00 per thousand cubic feet on four separate days last December. Forecasts of warmer weather had the opposite effect, producing downward price plunges of well over $1.00 per thousand cubic feet in a period of one trading day.

Underground working gas storage levels are currently about 31 percent below year-ago levels and a remarkable 23 percent below the previous 5-year average. Thus, assuming normal weather for the remainder of the heating season, wellhead prices this winter should probably stay above $6.00 per thousand cubic feet. We are projecting that winter (October-March) natural gas prices at the wellhead will average about $6.23 per thousand cubic feet, more than two and one half times the price of last winter. Without question, higher end-use prices will result from higher projected wellhead prices. If our base case projections hold, residential prices for natural gas this winter would be about 46 percent higher than last year during that period. For the entire year 2000, the average wellhead price for natural gas averaged an estimated $3.73 per thousand cubic feet, an increase of 72 percent from the previous year (Table A4). Prices should descend from their winter highs in the spring and summer of this year by about $2.00 per thousand cubic feet as the weather-related demand recedes. Still, for the year 2001, assuming normal weather and our projection of low underground storage levels through most of the year, we do not expect wellhead prices to drop below $4.00 per thousand cubic feet.

Figure 9. Retail Motor Gasoline Prices*: Base Case and 95% Confidence Interval



* Regular unleaded self-service

Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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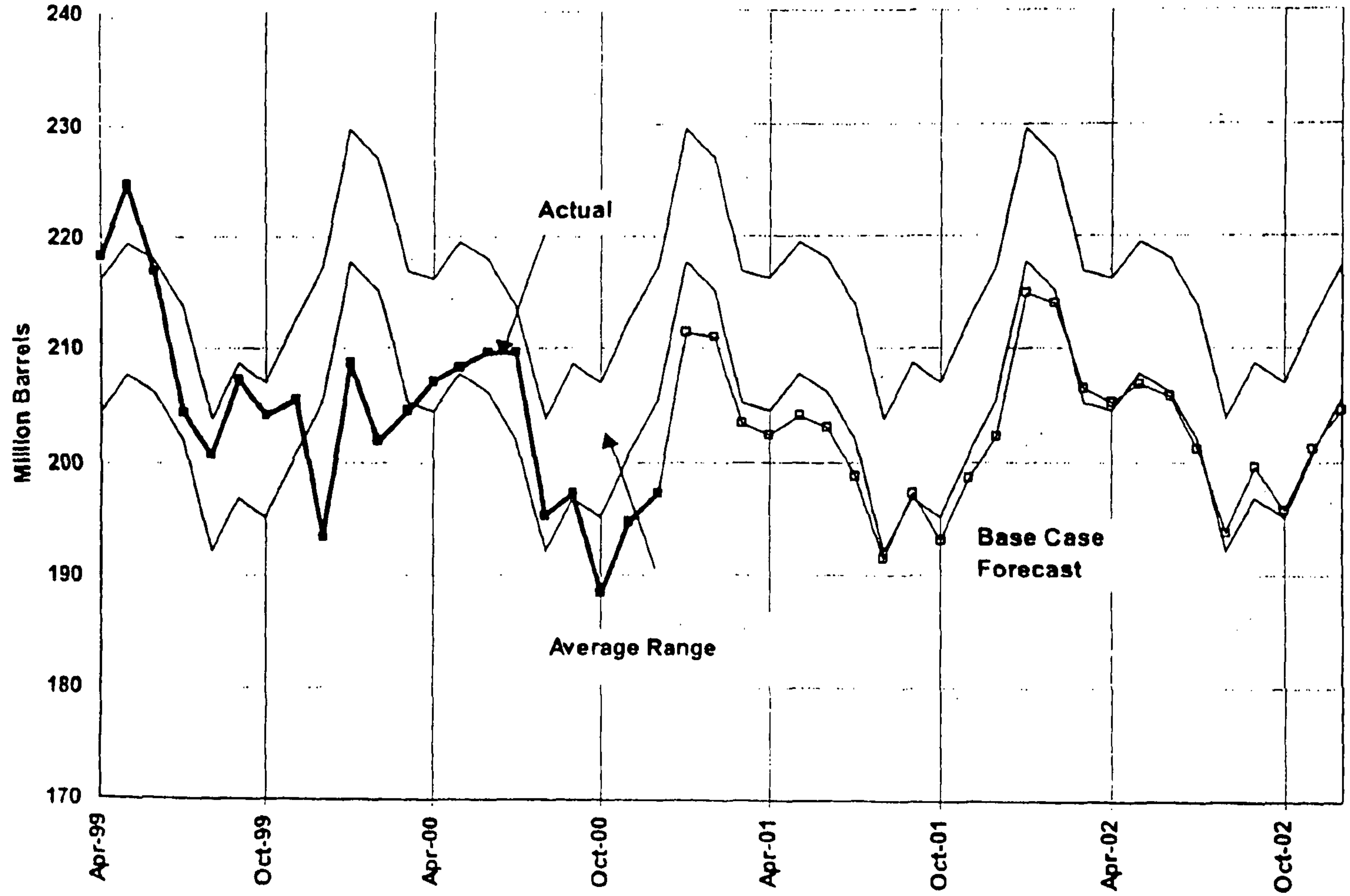
Figure 10. Gasoline Stocks



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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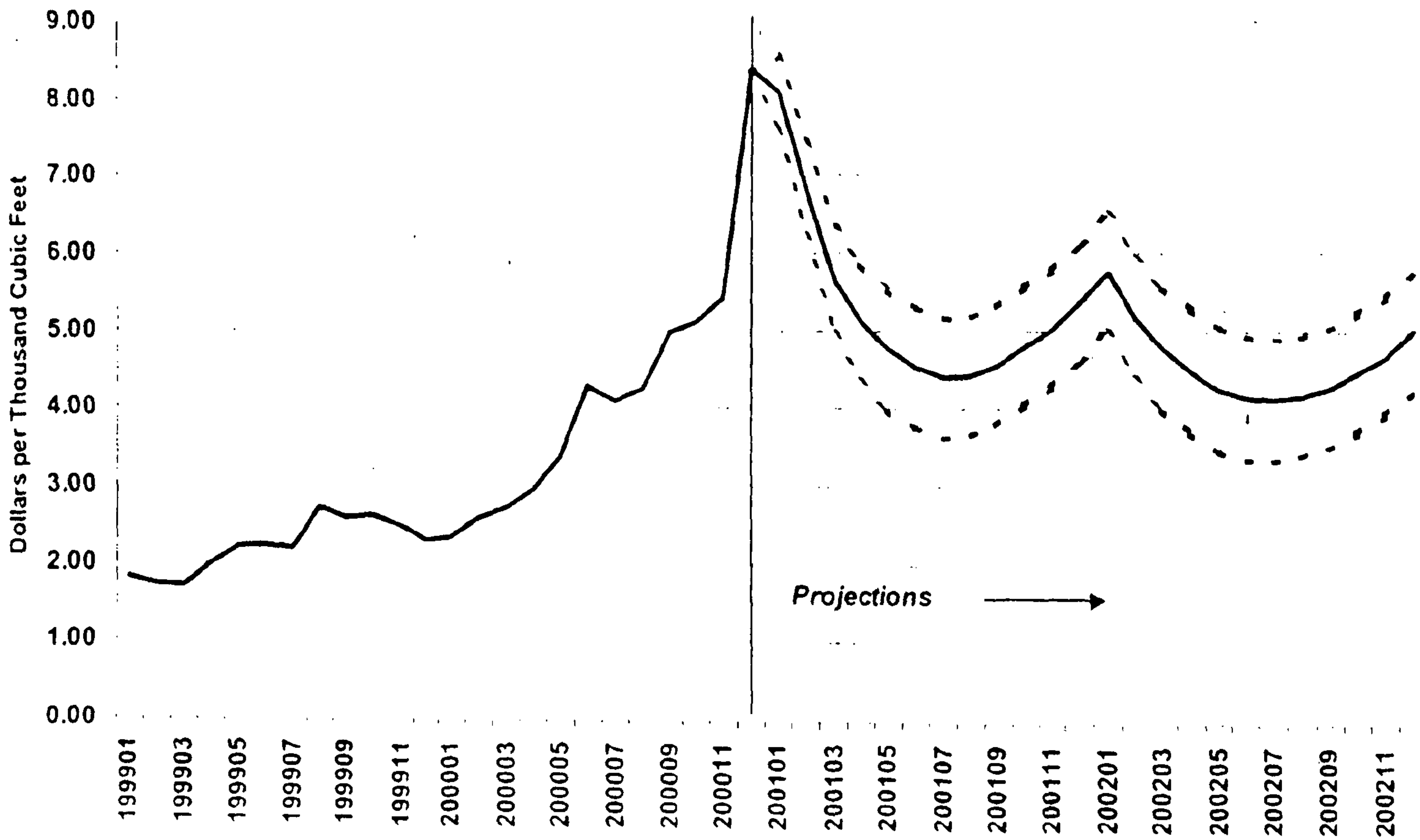
Figure 11. Natural Gas Spot Prices: Base Case and 95% Confidence Interval



Sources: History: Natural Gas Week; Projections: Short-Term Energy Outlook, January 2001.

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In fact, our forecast calls for an annual average wellhead price of over $5.00 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 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.

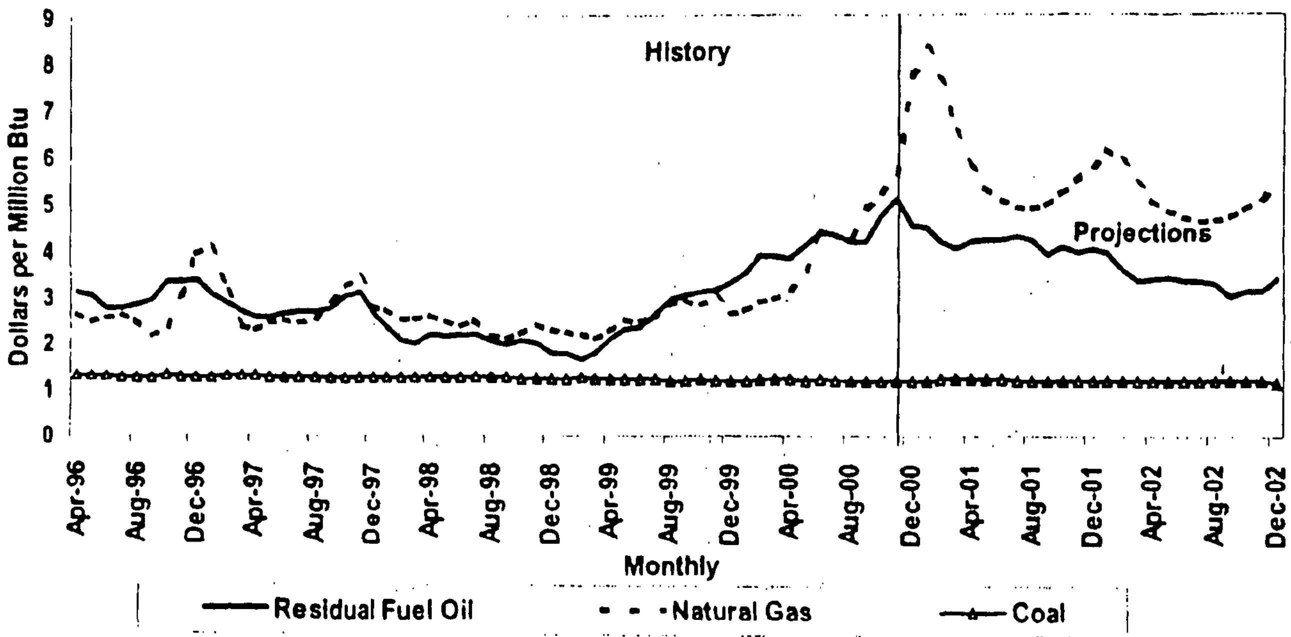
California continues to suffer particularly high natural gas prices (more than twice as high as recent national averages). High demand for gas-fired electricity generation, relatively low gas storage levels, low hydroelectric and nuclear power availability, coupled with heavy demand for gas for heating due to relatively cold temperatures in the region, has severely strained the gas supply system in that State. Adequate supplies of gas from out of state to meet strong gas demand are seriously limited due to pipeline capacity constraints at the State border.

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.

U.S. Oil Demand

The most recently available data indicate that total petroleum demand in 2000 grew less than 30,000 barrels per day, or 0.1 percent, from that of the previous year. That contrasts with the 600,000 barrels-per-day, or 3.2-percent growth of the previous year. Both first-quarter warm weather and price increases contributed to the sharp slowdown in growth. Motor gasoline demand declined an estimated 0.7 percent for the year in response to the mid-year run-up in retail prices. Although those prices have retreated somewhat from their mid-year peak, they are still well above those of a year ago. As a result, the decline in motor gasoline demand accelerated during the course of the year. Total jet fuel growth in 2000 averaged 1.8 percent compared to 3.1 percent in 1999. Commercial jet fuel demand, however, registered a 3.9-percent increase, even larger than the previous year's 3.5-percent growth rate despite an almost 10-percent increase in ticket prices. But jet fuel used as a winter-season blending component in diesel fuel declined substantially as a result of warm weather in the first quarter. Distillate fuel oil demand, however, grew an estimated 3.7 percent in 2000. The 5.4-percent growth in transportation demand, buoyed by continued robust economic expansion, was partly offset by the 1.7-percent decline in space-heating demand resulting from the mild winter weather. Despite rising prices and warm weather that depressed demand in the first half of the year, residual fuel oil demand eked out an estimated 1.1-percent growth

Figure 12. Fossil Fuel Prices to Electric Utilities



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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for 2000, led by recent recovery of demand by industrial customers and power generators. The colder-than-average weather, a retreat in prices from their mid-year peak, and the recent spike in natural gas prices contributed to a recovery in the second half of 2000. Industrial demand for residual_fuel oil staged a dramatic comeback beginning in the third quarter, and power-generation demand, having languished for much of the year, picked up substantially in the final quarter of the year.

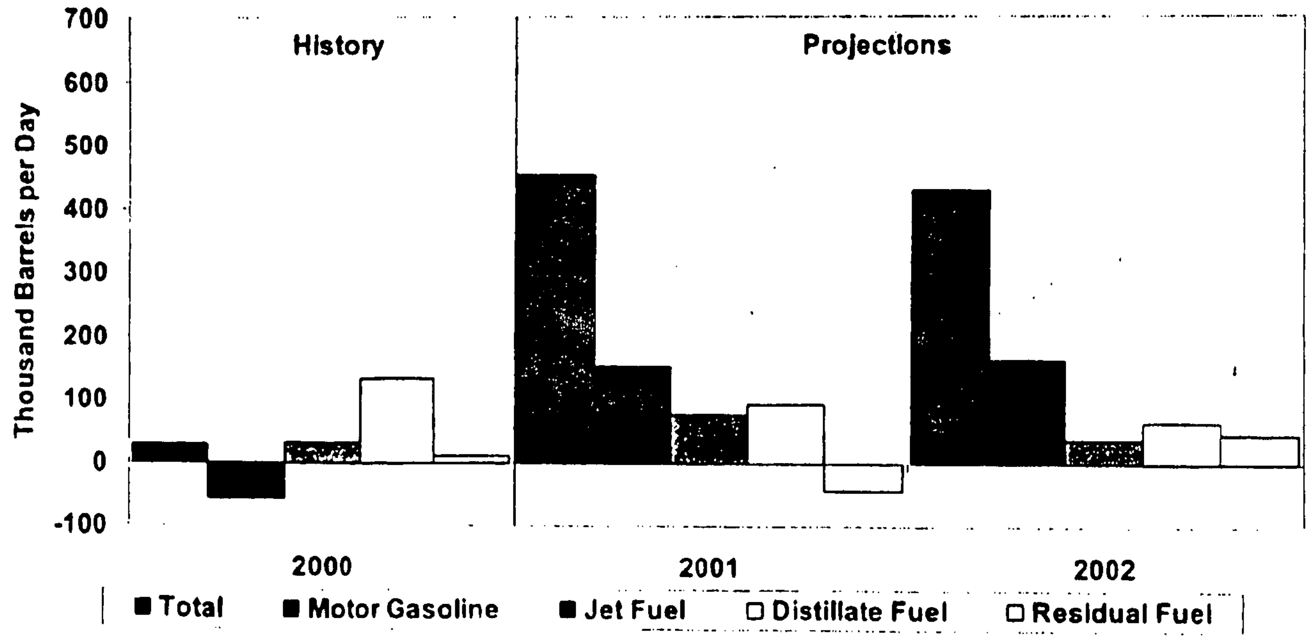
During the next 2 years, energy prices are projected to continue to moderate, disposable personal income is expected to grow at robust rates due in part to reductions in tax rates, and weather patterns are assumed to be normal. Petroleum demand is therefore projected to exhibit strong growth throughout the forecast interval, averaging 440,000 barrels per day, or 2.2 percent, per year (Figure 13). In the current year, total petroleum demand is projected to average 20 million barrels per day for the first time. Reversing last year's decline, motor gasoline demand is projected to increase once again, with growth averaging 1.8 percent per year. Commercial jet fuel demand is projected to continue to increase steadily at a 3.1-percent average rate. That demand is bolstered not only by continued increases in disposable income but also a slow taming of ticket-price inflation to 3 percent compared to 8 percent in the previous 2 years. Distillate fuel oil demand is projected to increase at a 2-percent average rate. Transportation diesel fuel demand is projected to expand 3 percent, but space-heating fuel demand is projected to remain flat. Residual fuel oil demand, however, is expected to remain flat during the forecast interval. Increases in shipments to power generators, reflecting price declines and assumptions of normal weather, are projected to be offset by declines in the other sectors brought about by a recovery by natural gas demand.

U.S. Oil Supply

Average domestic oil production is expected to increase by 58,000 barrels per day or 1.0 percent in 2001, to a level of 5.89 million barrels of oil per day (Figure 14). For 2002, a 0.9 percent decrease is expected and results in a production rate of 5.84 million barrels of oil per day average for the year.

Lower-48 States oil production is expected to increase by 5,000 barrels per day to a rate of 4.87 million barrels per day in 2001, and followed by a decrease of 77,000 barrels per day in 2002. Oil production from the Mars, Auger, Troika, Ursa, and Diana-Hoover Federal Offshore fields is expected to account for about 8.44 percent of the lower-48 oil production by the 4th quarter of 2002.

Figure 13. Petroleum Products Demand (Year-to-Year Change)



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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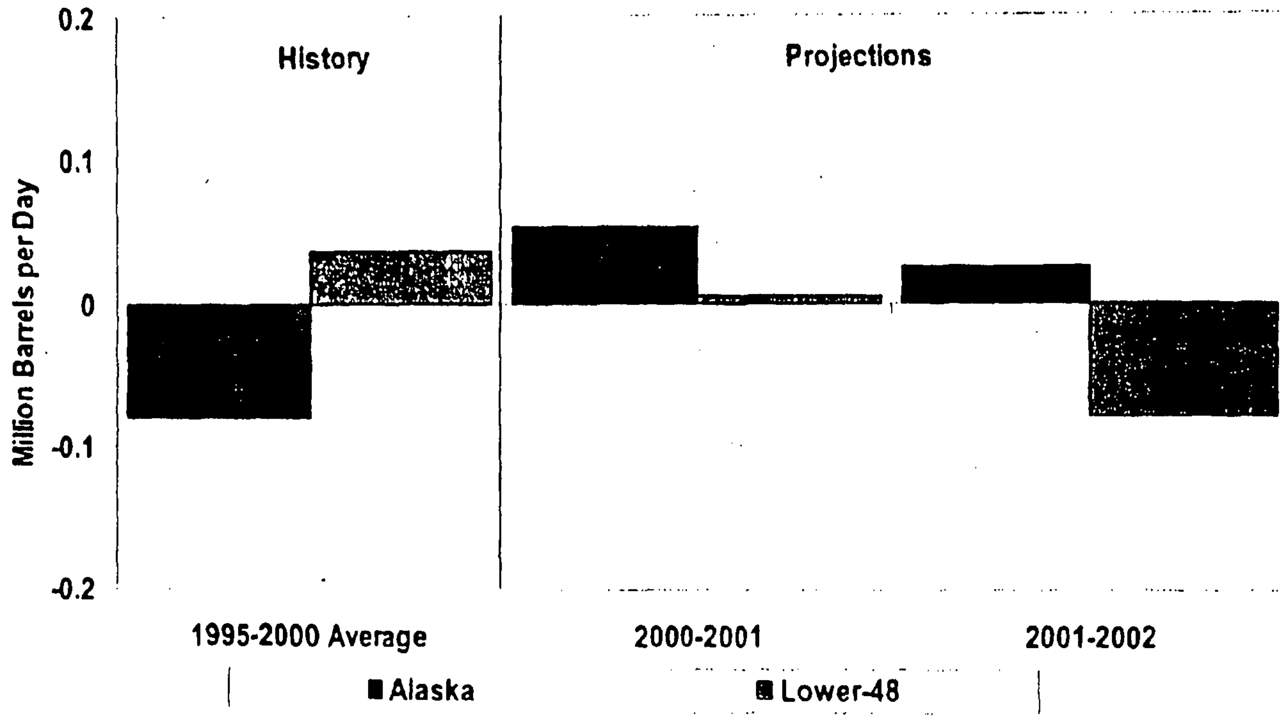
Figure 14. U.S. Crude Oil Production (Year-to-Year Change)



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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Alaska is expected to account for 17.9 percent of the total U.S. oil production in 2002. Its oil production is expected to increase by 5.4 percent in 2001 and again increase by 2.4 percent in 2002. A substantial portion of the oil production from Alaska comes from the giant Prudhoe Bay Field. 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 2001. The Alpine field is expected to come on in last quarter of 2000 at an initial rate of 40,000 barrels per day peaking at 80,000 barrels per day in mid 2001.

Natural Gas Demand and Supply

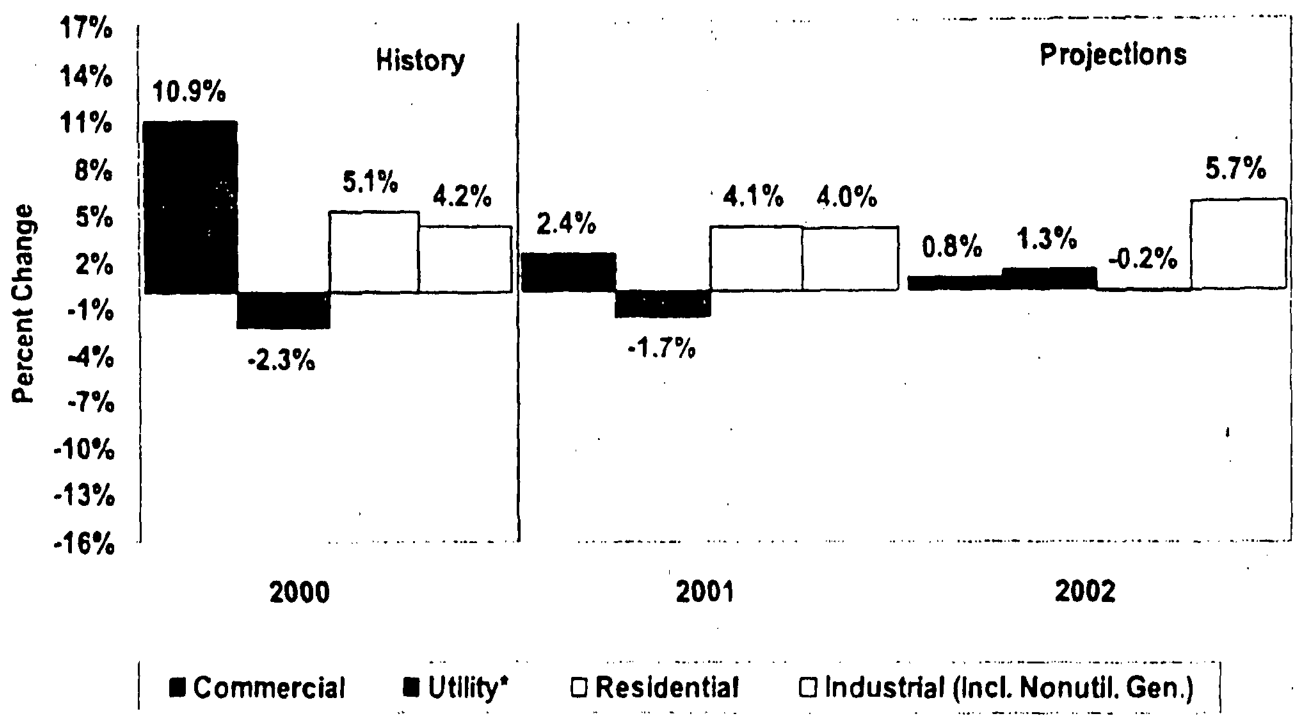
We estimate that severe winter weather in November and December 2000 pushed natural gas demand in these months to levels averaging 15 percent higher than a year ago, led by the residential and commercial sectors. The jump in natural gas prices served to dampen higher demand levels in the industrial and utility sectors, however, as generating units able to switch to other fuels presumably did so. Assuming normal weather for the remainder of the forecast period, natural gas demand is projected to grow by 2.9 percent in 2001 and by 2.7 percent in 2002, compared with estimated demand of 4.5 percent in 2000.

For the fourth quarter of 2000, gas-weighted heating degree-days were estimated to have been up by 28 percent over last year's relatively mild fourth quarter. Gas demand likewise is estimated to have increased by 10 percent over year ago. Over the entire 6 months of winter (October 1, 2000 to March 31, 2001) natural gas demand is expected to be up by 7 percent over last winter, assuming normal weather for the remainder of the season. This strong overall growth rate follows from the calculation that residential and commercial sector demand could be up by 17 percent over last winter.

The forecast for overall natural gas demand growth in 2001 is 2.9 percent for the year, down considerably from our projected growth rate in last month's Outlook (Figure 15). Partly, this lower growth rate for 2001 results from higher estimates for Q4 2000 demand due to colder-than-normal weather. Higher gas price projections also reduce expected industrial use in 2001 more than previously estimated. In 2002, the forecast calls for a somewhat slower 2.7 percent growth rate.

In 2001 and 2002, natural gas demand in the industrial sector is expected to increase by 4.0 percent and 5.7 percent, respectively. Natural gas demand for nonutility electricity generation in 2001 is now expected to be up by a solid 9.0 percent. Electric utility gas demand is still expected to remain about level with consumption rates seen in 2000. This distinction is due in part to sales of electric generating plants by electric utilities to unregulated generating companies, fuel consumption by which is currently recorded by EIA in the industrial sector. We assume, for the purposes of the forecast, that no additional sales of generating units to unregulated entities occur, but that assumption

Figure 15. Annual Changes in Natural Gas Demand by Sector



* Electric utility gas demand changes in recent years in part reflect sale of assets to the nonutility sector

Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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merely affects the label attached to the fuel demand source, not the overall demand trend.

We have increased our expected rate of gas production growth in North America for the year 2001. Significant increases in new supply will be required to meet expected increases in demand for space heating and power generation and to prevent storage conditions from deteriorating to a worse condition than has already been experienced this year. Domestic gas production for 2001 and 2002 is expected to increase as production responds to the high rates of drilling experienced over the past year. Production is estimated to have risen by 1.1 percent in 2000 and it is forecast to increase by significantly higher rates of 5.4 percent rate in 2001 and 2.5 percent in 2002. The U.S. natural gas rig count on December 29 was 879 rigs.

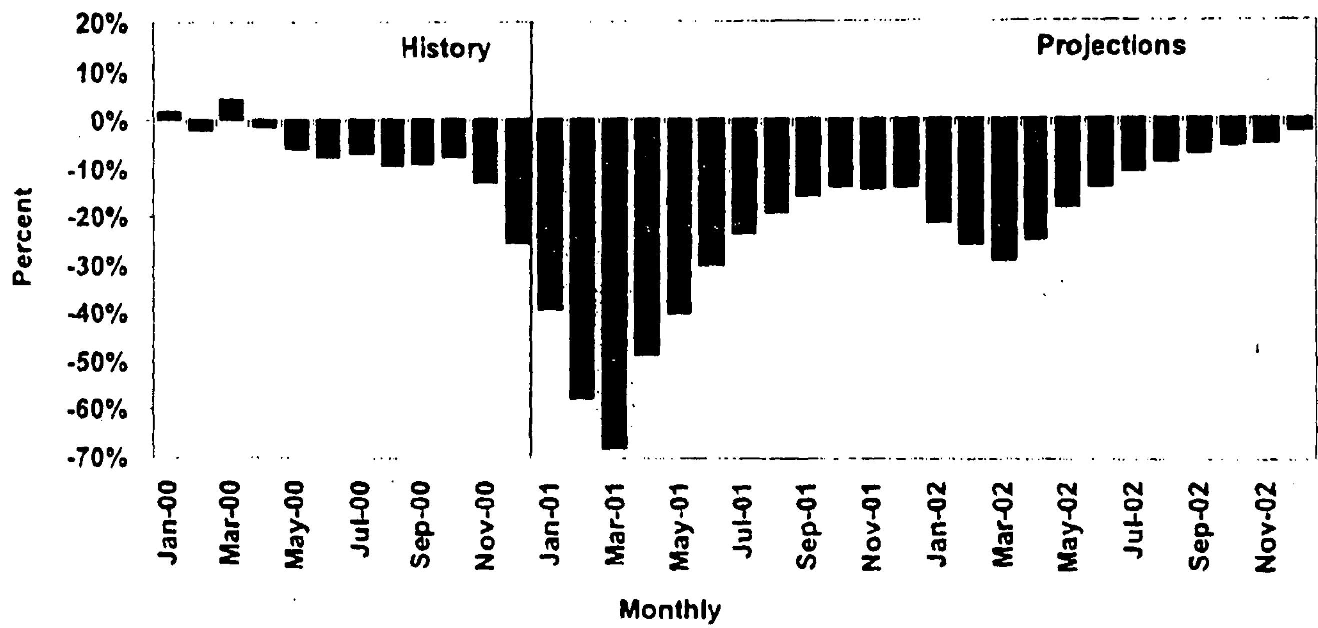
According to the American Gas Association (AGA), during the week ending December 29, a total of 209 billion cubic feet was withdrawn from storage, bringing the total of working gas to 53 percent full, or 1,729 bcf. Translating the AGA data into EIA end-month statistics, we estimate that gas stocks were about 780 bcf below year-ago levels and about 520 bcf below the previous 5-year average (Figure 16). With almost three months of winter still to go, falling stocks have raised fears about the domestic supply situation, helping to elevate spot and futures prices.

Net imports of natural gas are projected to rise by about 16 percent in 2001 and by another 4 percent in 2002. During the winter months, net imports are about 10 percent higher than flows during the rest of the year and usually increase to full pipeline capacity. While Canadian export capacity may not be fully utilized this winter, we expect net imports to be 7.8 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.

The critical power situation in California highlights the inter-related tightness in both electricity and gas markets. As environmental regulations on coal and oil fired generation units have become more strict over the past few years, gas fired generators began to take on more of the baseload burden. And as power generation demand has increased, demand for gas has increased with it.

California lacks the pipeline capacity to provide enough natural gas to all the new power plants in development, let alone its current supply demands. Also, the region is short on the electricity generating capacity and transmission wires to deliver enough power into a market that is growing at 4% annually. California had the highest gas

Figure 16. Working Gas in Storage (Percentage Difference from Previous 5-Year Average)



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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prices in the nation during the month of December. The lack of adequate power reserves this winter has been a repeat of last summer's situation. The economic impact of high natural gas and electricity prices is that many manufacturers of various commodities have chosen to interrupt operations and resell contracted energy back into the regional market.

Electricity Demand and Supply

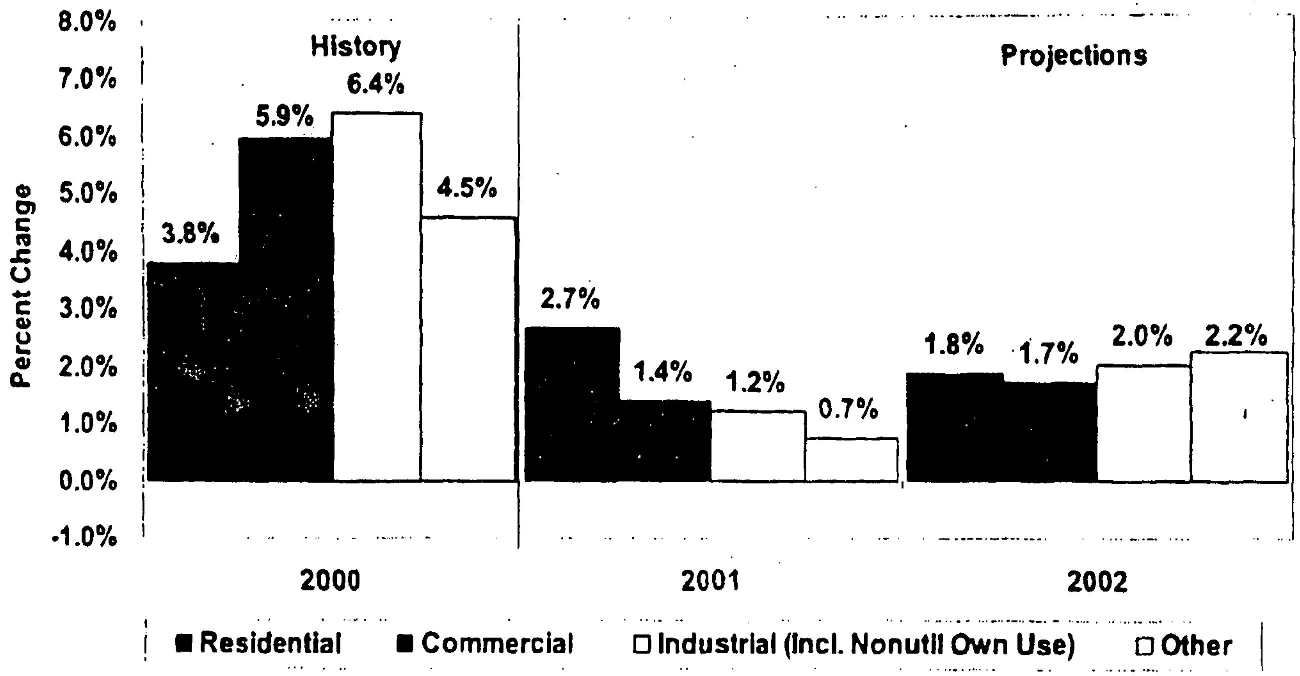
Total annual electricity demand growth (utility sales plus industrial generation for own use) is projected at 1.7 percent in 2001 and 1.8 percent in 2002. This is compared with estimated sales in 2000 that were 5.3 percent higher than the previous year's level, as much a result of the surprisingly low growth rate reported for 1999 as an indicator of robust growth in 2000. 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 almost 18 percent above last winter's HDD, which were well below normal. This is based on the very cold temperatures seen in November and December, as well as on the assumption that the remainder of the winter will be normal. This winter, total electricity sales by electric utilities are expected to be up by 3.9 percent over last winter's sales, driven by increased demand in the residential and commercial sectors, which are expected to be up by 6.6 and 3.4 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. The favorable price differential for oil relative to gas is expected to continue through the forecast period. Growth in coal-fired generation also turned positive in the fourth quarter of 2000. Nevertheless, by the second half of 2001, expected increases in gas-fired capacity are expected to keep gas demand for power generation growing.

Supply problems in California for gas-fired electricity generation have helped to boost gas prices and have frequently caused interruptible customers to be cut off in that state. The situation in California is characterized by low gas storage, gas pipeline bottlenecks, continuing cold weather, high demand and low hydro and nuclear electric power availability. California spot gas prices have spiked at as high as $59 per million Btu in December. Average California gas prices have dramatically outstripped prices elsewhere in the country this fall (Figure 18). These supply problems are following on last summer's supply problems with no obvious end currently visible.

Figure 17. Annual Changes in U.S. Electricity Demand



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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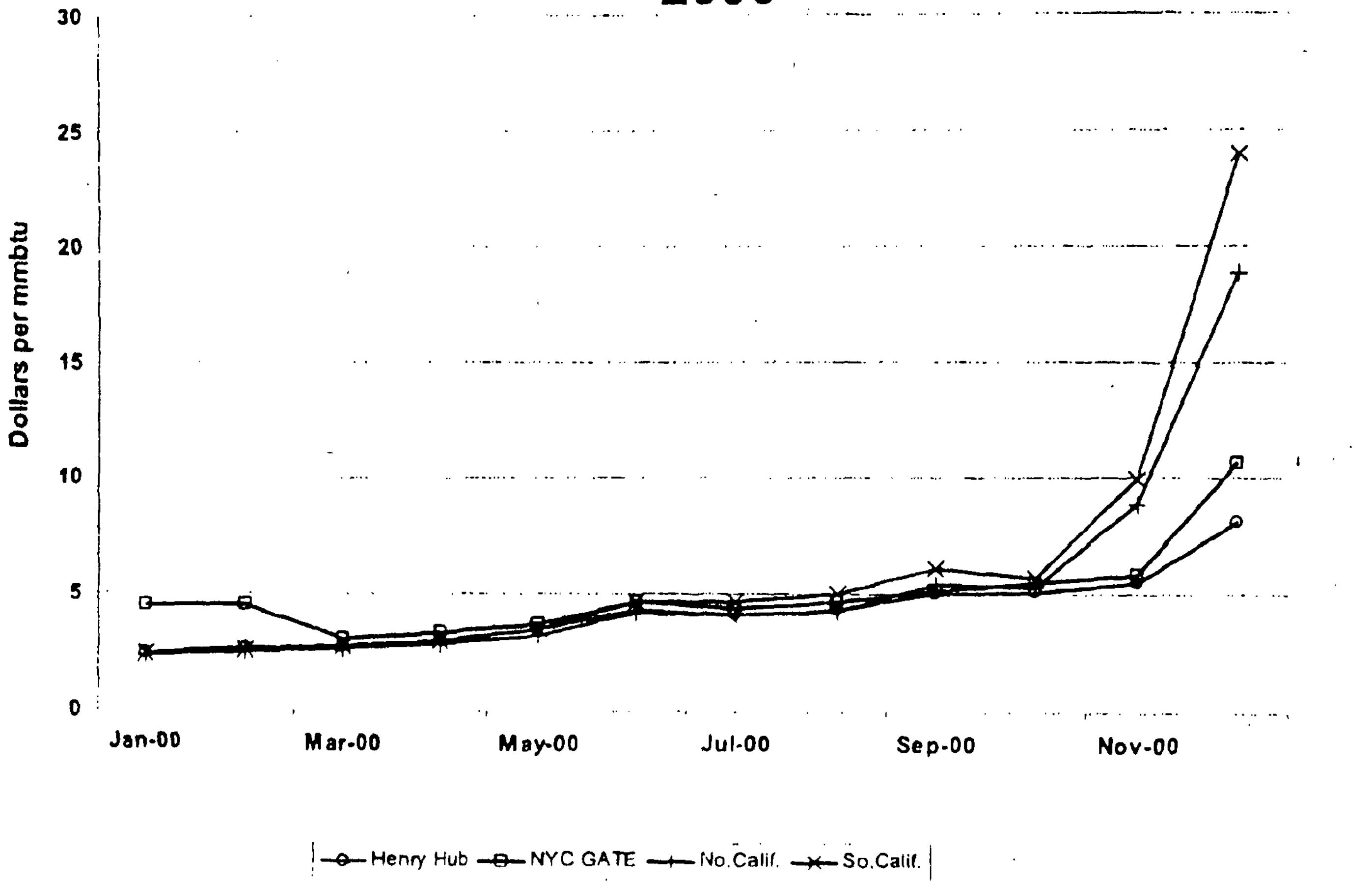
Figure 18.Comparison of Key Natural Gas Prices: Monthly Average Delivered to Pipeline Prices in 2000



Source: Natural Gas Week

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On December 13, 2000, the Clinton administration invoked its emergency powers to require power generators and marketers to sell their surplus electricity to California to prevent imminent blackouts. Under the Federal Power Act, out-of-state generators and marketers who were balking at selling power into California were required to do so immediately. A number of state generators were also refusing to sell power, fearing the utilities would not be able to pay spot market prices which have been as high as $3,000 per megawatt-hour, about 100 times higher than a year ago. However, on January 2, the FERC refused to order power generators to sell electricity to California utilities at rates under their cost of service, and on January 3, the California Public Utilities Commission (CPUC) issued an order that gave the utilities less than half the rate increases they were requesting. Pacific Gas and Electric and Southern California Edison both claim they are now facing bankruptcy due to unrecovered costs related to power sales.

Table HL1. U. S. Energy Supply and Demand

	Year				Annual Percentage Change		
	1999	2000	2001	2002	1999-2000	2000-2001	2001-2002
Real Gross Domestic Product (GDP) (billion chained 1996 dollars)	**8876**	*9334*	*9634*	*10033*	5.2	3.2	4.1
Imported Crude Oil Price [a] (nominal dollars per barrel)	**17.22**	*27.86*	*26.92*	*21.28*	61.8	-3.4	-21.0
Petroleum Supply (million barrels per day) Crude Oil Production [b]	**5.88**	*5.84*	*5.89*	*5.84*	-0.7	0.9	-0.8
Total Petroleum Net Imports (including SPR)	**9.91**	*10.08*	*10.76*	*11.18*	1.7	6.7	3.9
Energy Demand							
World Petroleum (million barrels per day)	**74.8**	*75.9*	*77.9*	*79.9*	1.5	2.6	2.6
Petroleum (million barrels per day)	**19.52**	*19.55*	*20.00*	*20.43*	0.2	2.3	2.2
Natural Gas (trillion cubic feet)	**21.70**	*22.69*	*23.35*	*23.98*	4.6	2.9	2.7
Coal [c] (million short tons)	**1044**	*1063*	*1105*	*1133*	1.8	4.0	2.5
Electricity (billion kilowatthours)							
Utility Sales [d]	**3236**	*3398*	*3447*	*3512*	5.0	1.4	1.9
Nonutility/Sales [e]	**185**	*206*	*218*	*220*	11.4	5.8	0.9
Total	**3421**	*3603*	*3665*	*3733*	5.3	1.7	1.9
Total Energy Demand [f] (quadrillion Btu)	**97.1**	*98.3*	*100.2*	*102.3*	1.2	1.9	2.1
Total Energy Demand per Dollar of GDP (thousand Btu per 1996 Dollar)	**10.94**	*10.53*	*10.40*	*10.19*	-3.7	-1.2	-2.0
Renewable Energy as Percent of Total [g]	**7.2**	*7.1*	*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 annual electric utility sales for historical periods are initially derived from the sum of monthly sales figures based on submissions by electric utilities of Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions." Final annual totals are taken from compilations from Form EIA -861, "Annual Electric Utility Report."

[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 1999 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 CONTROL 1200.

Table 1. U.S. Macroeconomic and Weather Assumptions

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Macroeconomic [a]															
Real Gross Domestic Product (billion chained 1996 dollars - SAAR)	**9192**	**9319**	**9374**	*9453*	*9520*	*9591*	*9669*	*9757*	*9866*	*9972*	*10087*	*10207*	*9334*	*9634*	*10033*
Percentage Change from Prior Year	**5.3**	**6.1**	**5.3**	*4.1*	*3.6*	*2.9*	*3.1*	*3.2*	*3.6*	*4.0*	*4.3*	*4.6*	*5.2*	*3.2*	*4.1*
Annualized Percent Change from Prior Quarter	**4.7**	**5.5**	**2.3**	*3.4*	*2.8*	*3.0*	*3.2*	*3.7*	*4.5*	*4.3*	*4.6*	*4.8*			
GDP Implicit Price Deflator (Index, 1996=1.000)	**1.062**	**1.068**	**1.073**	*1.080*	*1.087*	*1.092*	*1.096*	*1.101*	*1.107*	*1.112*	*1.116*	*1.121*	*1.071*	*1.094*	*1.114*
Percentage Change from Prior Year	**1.8**	**2.1**	**2.3**	*2.6*	*2.4*	*2.2*	*2.2*	*1.9*	*1.8*	*1.8*	*1.8*	*1.8*	*2.2*	*2.2*	*1.8*
Real Disposable Personal Income (billion chained 1996 Dollars - SAAR)	**6443**	**6502**	**6541**	*6560*	*6646*	*6735*	*6818*	*6888*	*6977*	*7059*	*7139*	*7221*	*6512*	*6771*	*7099*
Percentage Change from Prior Year	**2.9**	**3.1**	**3.1**	*2.3*	*3.1*	*3.6*	*4.2*	*5.0*	*5.0*	*4.8*	*4.7*	*4.8*	*2.9*	*4.0*	*4.8*
Manufacturing Production (Index, 1996=1.000)	**1.216**	**1.239**	**1.251**	*1.262*	*1.275*	*1.285*	*1.295*	*1.303*	*1.313*	*1.323*	*1.336*	*1.348*	*1.242*	*1.290*	*1.330*
Percentage Change from Prior Year	**5.9**	**6.6**	**6.5**	*5.6*	*4.9*	*3.7*	*3.5*	*3.2*	*3.0*	*3.0*	*3.2*	*3.5*	*6.2*	*3.8*	*3.1*
OECD Economic Growth (percent) [b]													*3.7*	*3.1*	*3.3*
Weather [c]															
Heating Degree-Days															
U.S.	**2023**	**485**	**96**	*1854*	*2236*	*519*	*86*	*1622*	*2234*	*518*	*86*	*1622*	*4458*	*4463*	*4459*
New England	**3007**	**909**	**200**	*2383*	*3177*	*885*	*167*	*2238*	*3174*	*883*	*167*	*2237*	*6499*	*6467*	*6462*
Middle Atlantic	**2713**	**692**	**126**	*2194*	*2895*	*701*	*105*	*2003*	*2891*	*700*	*105*	*2002*	*5725*	*5703*	*5698*
U.S. Gas-Weighted	**2115**	**512**	**100**	*1956*	*2354*	*555*	*90*	*1714*	*2351*	*555*	*90*	*1714*	*4683*	*4714*	*4710*
Cooling Degree-Days (U.S.)	**45**	**380**	**759**	*68*	*32*	*346*	*781*	*76*	*33*	*347*	*782*	*76*	*1252*	*1235*	*1237*

[a] Macroeconomic projections from DRI/McGraw-Hill model forecasts are seasonally adjusted at annual rates and modified as appropriate to the mid world oil price case.

[b] OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

[c] Population-weighted degree days. A degree day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population.

SAAR: Seasonally-adjusted annualized rate.

Note: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release G.17(419)*. Projections of OECD growth are based on WEFA Group, "World Economic Outlook," Volume 1. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL1200.

Table 2. U.S. Energy Indicators: Mid World Oil Price Case

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Macroeconomic [a]															
Real Fixed Investment															
(billion chained 1996 dollars-SAAR)	**1731**	**1779**	**1792**	*1815*	*1834*	*1854*	*1868*	*1881*	*1898*	*1926*	*1956*	*1988*	*1779*	*1860*	*1942*
Real Exchange Rate															
(index)	**1.163**	**1.210**	**1.247**	*1.277*	*1.287*	*1.263*	*1.257*	*1.240*	*1.210*	*1.197*	*1.187*	*1.173*	*1.224*	*1.262*	*1.192*
Business Inventory Change															
(billion chained 1996 dollars-SAAR)	**10.3**	**17.6**	**21.0**	*14.4*	*7.6*	*5.8*	*5.4*	*3.9*	*5.3*	*5.2*	*6.4*	*7.3*	*15.8*	*5.7*	*6.0*
Producer Price Index															
(index, 1982=1.000)	**1.301**	**1.321**	**1.334**	*1.351*	*1.359*	*1.349*	*1.340*	*1.336*	*1.342*	*1.346*	*1.349*	*1.353*	*1.327*	*1.346*	*1.347*
Consumer Price Index															
(index, 1982-1984=1.000)	**1.702**	**1.717**	**1.730**	*1.746*	*1.756*	*1.762*	*1.768*	*1.775*	*1.785*	*1.793*	*1.802*	*1.811*	*1.724*	*1.765*	*1.798*
Petroleum Product Price Index															
(index, 1982=1.000)	**0.833**	**0.911**	**0.931**	*0.959*	*0.936*	*0.903*	*0.859*	*0.847*	*0.827*	*0.753*	*0.691*	*0.693*	*0.909*	*0.886*	*0.741*
Non-Farm Employment															
(millions)	**130.6**	**131.6**	**131.6**	*132.1*	*132.2*	*132.5*	*132.8*	*133.1*	*133.5*	*133.8*	*134.4*	*134.9*	*131.5*	*132.7*	*134.1*
Commercial Employment															
(millions)	**91.2**	**91.7**	**92.1**	*92.6*	*92.9*	*93.2*	*93.6*	*94.0*	*94.4*	*94.9*	*95.4*	*96.0*	*91.9*	*93.4*	*95.2*
Total Industrial Production															
(index, 1996=1.000)	**1.187**	**1.210**	**1.221**	*1.229*	*1.241*	*1.250*	*1.258*	*1.265*	*1.273*	*1.282*	*1.294*	*1.307*	*1.212*	*1.253*	*1.289*
Housing Stock															
(millions)	**115.7**	**115.8**	**116.2**	*116.6*	*116.9*	*117.2*	*117.5*	*117.8*	*118.1*	*118.4*	*118.7*	*119.1*	*116.1*	*117.4*	*118.6*
Miscellaneous															
Gas Weighted Industrial Production															
(index, 1996=1.000)	**1.096**	**1.096**	**1.091**	*1.095*	*1.102*	*1.112*	*1.121*	*1.130*	*1.140*	*1.148*	*1.156*	*1.164*	*1.094*	*1.116*	*1.152*
Vehicle Miles Traveled [b]															
(million miles/day)	**6820**	**7596**	**7632**	*7240*	*7046*	*7755*	*7782*	*7338*	*7088*	*7828*	*8049*	*7620*	*7323*	*7482*	*7649*
Vehicle Fuel Efficiency															
(index, 1999=1.000)	**1.004**	**1.018**	**0.994**	*1.003*	*1.019*	*1.021*	*1.000*	*0.994*	*1.011*	*1.014*	*1.013*	*1.009*	*1.004*	*1.008*	*1.012*
Real Vehicle Fuel Cost															
(cents per mile)	**4.17**	**4.28**	**4.27**	*4.28*	*4.00*	*4.04*	*3.98*	*3.97*	*3.82*	*3.61*	*3.38*	*3.36*	*4.25*	*4.00*	*3.54*
Air Travel Capacity															
(mill. available ton-miles/day)	**452.9**	**481.0**	**498.5**	*485.9*	*482.5*	*505.1*	*522.0*	*510.7*	*505.4*	*525.4*	*543.0*	*532.8*	*479.7*	*505.2*	*526.8*
Aircraft Utilization															
(mill. revenue ton-miles/day)	**254.9**	**283.9**	**297.1**	*281.4*	*276.9*	*295.6*	*309.6*	*294.4*	*289.2*	*308.0*	*322.7*	*308.8*	*279.4*	*294.2*	*307.3*
Airline Ticket Price Index															
(index, 1982-1984=1.000)	**2.309**	**2.419**	**2.474**	*2.381*	*2.449*	*2.479*	*2.487*	*2.513*	*2.545*	*2.546*	*2.536*	*2.549*	*2.396*	*2.482*	*2.544*
Raw Steel Production															
(millions tons)	**29.02**	**29.30**	**29.10**	*29.14*	*28.99*	*29.00*	*28.36*	*28.64*	*28.57*	*28.94*	*28.61*	*29.17*	*116.56*	*114.99*	*115.29*

[a] Macroeconomic projections from DRI/McGraw-Hill model forecasts are seasonally adjusted at annual rates and modified as appropriate to the mid world oil price case.

[b] Includes all highway travel.

SAAR: Seasonally-adjusted annualized rate.

Note: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release* G.17(419); U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL1200.

Table 3. International Petroleum Supply and Demand: Mid World Oil Price Case

(Million Barrels per Day, Except OECD Commercial Stocks)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Demand [a]															
OECD															
U.S. (50 States)	**19.1**	**19.3**	**19.8**	*19.9*	*19.8*	*19.8*	*20.1*	*20.3*	*20.2*	*20.2*	*20.6*	*20.7*	*19.5*	*20.0*	*20.4*
U.S. Territories	**0.4**	**0.3**	**0.4**	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*	*0.4*	*0.4*
Canada	**1.9**	**1.9**	**2.0**	*2.0*	*2.0*	*1.9*	*2.1*	*2.1*	*2.0*	*2.0*	*2.1*	*2.1*	*2.0*	*2.0*	*2.1*
Europe	**14.5**	**13.9**	**14.4**	*15.2*	*14.9*	*14.0*	*14.5*	*15.2*	*15.1*	*14.1*	*14.7*	*15.3*	*14.5*	*14.7*	*14.8*
Japan	**6.0**	**5.0**	**5.4**	*5.9*	*6.2*	*5.1*	*5.3*	*5.7*	*6.2*	*5.1*	*5.3*	*5.8*	*5.6*	*5.6*	*5.6*
Australia and New Zealand	**1.0**	**1.0**	**1.0**	*1.1*	*1.0*	*1.0*	*1.0*	*1.1*	*1.1*	*1.1*	*1.0*	*1.1*	*1.0*	*1.0*	*1.1*
Total OECD	**42.9**	**41.4**	**42.8**	*44.5*	*44.3*	*42.2*	*43.4*	*44.8*	*45.0*	*42.9*	*44.2*	*45.5*	*42.9*	*43.7*	*44.4*
Non-OECD															
Former Soviet Union	**3.8**	**3.6**	**3.6**	*3.6*	*3.8*	*3.7*	*3.7*	*3.7*	*3.9*	*3.7*	*3.7*	*3.7*	*3.7*	*3.7*	*3.8*
Europe	**1.6**	**1.6**	**1.6**	*1.6*	*1.7*	*1.7*	*1.7*	*1.7*	*1.8*	*1.7*	*1.7*	*1.7*	*1.6*	*1.7*	*1.7*
China	**4.6**	**4.5**	**4.5**	*4.5*	*4.8*	*4.8*	*4.7*	*4.8*	*5.1*	*5.0*	*5.0*	*5.0*	*4.5*	*4.8*	*5.0*
Other Asia	**9.2**	**9.2**	**9.0**	*9.4*	*9.7*	*9.7*	*9.4*	*9.9*	*10.2*	*10.2*	*9.9*	*10.4*	*9.2*	*9.7*	*10.2*
Other Non-OECD	**13.7**	**14.0**	**14.1**	*14.0*	*14.2*	*14.4*	*14.5*	*14.5*	*14.5*	*14.8*	*14.9*	*14.8*	*14.0*	*14.4*	*14.8*
Total Non-OECD	**32.9**	**33.0**	**32.8**	*33.2*	*34.2*	*34.3*	*34.0*	*34.5*	*35.5*	*35.5*	*35.2*	*35.7*	*33.0*	*34.2*	*35.5*
Total World Demand	**75.8**	**74.4**	**75.8**	*77.6*	*78.6*	*76.5*	*77.4*	*79.2*	*80.5*	*78.4*	*79.4*	*81.2*	*75.9*	*77.9*	*79.9*
Supply [b]															
OECD															
U.S. (50 States)	**9.1**	**9.1**	**9.0**	*9.1*	*9.2*	*9.2*	*9.1*	*9.2*	*9.1*	*9.2*	*9.1*	*9.1*	*9.1*	*9.2*	*9.1*
Canada	**2.7**	**2.7**	**2.7**	*2.8*	*2.8*	*2.8*	*2.9*	*2.9*	*2.8*	*2.8*	*3.0*	*3.0*	*2.7*	*2.8*	*2.9*
North Sea [c]	**6.6**	**6.2**	**6.2**	*6.4*	*6.4*	*6.2*	*6.3*	*6.7*	*6.4*	*6.1*	*6.2*	*6.7*	*6.4*	*6.4*	*6.4*
Other OECD	**1.7**	**1.7**	**1.6**	*1.7*	*1.7*	*1.7*	*1.6*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*
Total OECD	**20.2**	**19.7**	**19.6**	*20.1*	*20.1*	*19.9*	*20.0*	*20.6*	*20.0*	*19.8*	*20.0*	*20.5*	*19.9*	*20.1*	*20.1*
Non-OECD															
OPEC	**29.3**	**30.7**	**31.6**	*31.5*	*31.3*	*31.3*	*31.3*	*31.5*	*32.4*	*32.4*	*32.5*	*32.5*	*30.8*	*31.4*	*32.5*
Former Soviet Union	**7.6**	**7.7**	**7.9**	*8.0*	*8.0*	*8.1*	*8.3*	*8.3*	*8.3*	*8.5*	*8.6*	*8.6*	*7.8*	*8.2*	*8.5*
China	**3.3**	**3.3**	**3.2**	*3.3*	*3.2*	*3.2*	*3.2*	*3.2*	*3.1*	*3.1*	*3.1*	*3.1*	*3.3*	*3.2*	*3.1*
Mexico	**3.5**	**3.5**	**3.5**	*3.6*	*3.8*	*3.8*	*3.8*	*3.7*	*4.0*	*4.0*	*4.0*	*3.9*	*3.5*	*3.8*	*4.0*
Other Non-OECD	**11.2**	**11.2**	**11.4**	*11.4*	*11.1*	*11.2*	*11.4*	*11.5*	*11.4*	*11.5*	*11.7*	*11.8*	*11.3*	*11.3*	*11.6*
Total Non-OECD	**54.8**	**56.4**	**57.7**	*57.8*	*57.4*	*57.7*	*58.0*	*58.3*	*59.2*	*59.5*	*60.0*	*60.0*	*56.7*	*57.8*	*59.7*
Total World Supply	**75.0**	**76.1**	**77.3**	*77.8*	*77.4*	*77.5*	*78.0*	*78.9*	*79.2*	*79.3*	*80.0*	*80.5*	*76.6*	*78.0*	*79.8*
Stock Changes															
Net Stock Withdrawals or Additions (-)															
U.S. (50 States including SPR)	**0.2**	**-0.6**	**0.0**	*0.6*	*0.2*	*-0.6*	*-0.4*	*0.2*	*0.2*	*-0.6*	*-0.3*	*0.4*	*0.1*	*-0.1*	*-0.1*
Other	**0.6**	**-1.1**	**-1.5**	*-0.8*	*1.0*	*-0.5*	*-0.3*	*0.2*	*1.1*	*-0.3*	*-0.3*	*0.2*	*-0.7*	*0.1*	*0.2*
Total Stock Withdrawals	**0.7**	**-1.7**	**-1.5**	*-0.2*	*1.1*	*-1.1*	*-0.6*	*0.4*	*1.2*	*-0.9*	*-0.6*	*0.6*	*-0.7*	*0.0*	*0.1*
OECD Comm. Stocks, End (bil. bbls.)	**2.6**	**2.6**	**2.6**	*2.6*	*2.7*	*2.8*	*2.8*	*2.8*	*2.7*	*2.8*	*2.9*	*2.8*	*2.6*	*2.8*	*2.8*
Non-OPEC Supply	**45.7**	**45.4**	**45.7**	*46.3*	*46.1*	*46.2*	*46.7*	*47.3*	*46.8*	*46.9*	*47.4*	*48.0*	*45.8*	*46.6*	*47.3*
Net Exports from Former Soviet Union	**3.9**	**4.1**	**4.3**	*4.4*	*4.2*	*4.5*	*4.6*	*4.6*	*4.5*	*4.7*	*4.9*	*4.9*	*4.2*	*4.5*	*4.7*

[a]Demand for petroleum by the OECD countries is synonymous with "petroleum product supplied," which is defined in the glossary of the EIA *Petroleum Supply Monthly*, DOE/EIA-0109. Demand for petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

[b]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources.

[c]Includes offshore supply from Denmark, Germany, the Netherlands, Norway, and the United Kingdom.

OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

OPEC: Organization of Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

SPR: Strategic Petroleum Reserve

Former Soviet Union: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

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

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Sources: Energy Information Administration: latest data available from EIA databases supporting the following reports: *International Petroleum Statistics Report*, DOE/EIA-0520; Organization for Economic Cooperation and Development, Annual and Monthly Oil Statistics Database.

Table 4. U. S. Energy Prices

(Nominal Dollars)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Imported Crude Oil Prices															
Imported Average[a]	26.84	26.55	29.11	28.85	26.99	27.45	27.32	25.91	23.86	21.66	20.13	19.61	27.86	26.92	21.28
WTI[b] Spot Average	28.82	28.78	31.61	31.96	29.14	29.49	29.33	27.89	25.87	23.66	22.13	21.62	30.29	28.96	23.32
Natural Gas Wellhead															
(dollars per thousand cubic feet)	2.26	3.06	3.87	5.61	6.82	4.82	4.38	4.89	5.20	4.34	4.15	4.59	3.73	5.22	4.57
Petroleum Products															
Gasoline Retail[c] (dollars per gallon)															
All Grades	1.44	1.57	1.56	1.54	1.44	1.52	1.50	1.44	1.39	1.37	1.31	1.26	1.53	1.48	1.33
Regular Unleaded	1.40	1.53	1.52	1.50	1.40	1.49	1.47	1.40	1.35	1.34	1.28	1.22	1.49	1.44	1.30
No. 2 Diesel Oil, Retail (dollars per gallon)	1.42	1.41	1.50	1.59	1.59	1.52	1.47	1.46	1.39	1.34	1.29	1.30	1.48	1.51	1.33
No. 2 Heating Oil, Wholesale (dollars per gallon)	0.85	0.78	0.91	0.98	0.94	0.84	0.82	0.84	0.78	0.66	0.61	0.66	0.89	0.87	0.69
No. 2 Heating Oil, Retail (dollars per gallon)	1.31	1.17	1.23	1.45	1.50	1.31	1.17	1.26	1.24	1.09	0.97	1.08	1.33	1.37	1.14
No. 6 Residual Fuel Oil, Retail[d] (dollars per barrel)	23.64	24.56	25.11	29.49	27.56	25.69	24.98	24.91	23.53	20.56	19.28	19.83	25.93	25.85	20.80
Electric Utility Fuels															
Coal (dollars per million Btu)	1.21	1.21	1.19	1.19	1.20	1.21	1.20	1.19	1.19	1.20	1.18	1.17	1.20	1.20	1.19
Heavy Fuel Oil[e] (dollars per million Btu)	3.74	4.18	4.22	4.69	4.27	4.20	4.16	4.01	3.64	3.36	3.23	3.21	4.23	4.17	3.36
Natural Gas (dollars per million Btu)	2.85	3.78	4.47	6.00	7.42	5.39	4.97	5.47	5.85	4.88	4.68	5.14	4.28	5.53	4.99
Other Residential															
Natural Gas (dollars per thousand cubic feet)	6.43	7.68	10.08	8.99	9.95	10.46	10.72	9.02	9.16	9.99	10.94	9.11	7.73	9.83	9.42
Electricity (cents per kilowatthour)	7.76	8.34	8.56	8.11	7.84	8.46	8.74	8.27	7.95	8.53	8.82	8.35	8.21	8.34	8.43

[a]Refiner acquisition cost (RAC) of imported crude oil.

[b]West Texas Intermediate.

[c]Average self-service cash prices.

[d]Average for all sulfur contents.

[e]Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the first quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Table 5. U.S. Petroleum Supply and Demand: Mid World Oil Price Case

(Million Barrels per Day, Except Closing Stocks)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Supply															
Crude Oil Supply															
Domestic Production [a]	5.86	5.84	5.79	5.85	5.95	5.91	5.83	5.88	5.89	5.87	5.82	5.78	5.84	5.89	5.84
Alaska	1.02	0.97	0.91	0.99	1.02	1.01	0.98	1.08	1.06	1.05	1.04	1.05	0.97	1.02	1.05
Lower 48	4.84	4.87	4.88	4.87	4.93	4.90	4.85	4.81	4.84	4.82	4.78	4.74	4.87	4.87	4.79
Net Imports (including SPR) [b]	8.12	9.16	9.49	8.68	8.82	9.43	9.72	9.34	9.15	9.88	9.99	9.54	8.86	9.33	9.64
Other SPR Supply	0.02	0.17	0.07	0.07	0.00	0.00	0.17	0.17	0.00	0.00	0.00	0.00	0.08	0.09	0.00
SPR Stock Withdrawn or Added (-)	-0.02	0.01	-0.02	0.33	0.00	0.00	-0.17	-0.17	0.00	0.00	0.00	0.00	0.07	-0.09	0.00
Other Stock Withdrawn or Added (-)	-0.13	0.06	0.12	-0.09	-0.19	-0.02	0.17	0.03	-0.22	-0.05	0.14	0.00	-0.01	0.00	-0.03
Product Supplied and Losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unaccounted-for Crude Oil	0.31	0.37	0.22	0.36	0.21	0.22	0.22	0.21	0.21	0.22	0.23	0.22	0.31	0.21	0.22
Total Crude Oil Supply	14.16	15.41	15.63	15.10	14.79	15.54	15.77	15.30	15.03	15.92	16.17	15.54	15.08	15.35	15.67
Other Supply															
NGL Production	1.97	1.94	1.93	1.92	1.95	1.95	1.93	2.00	2.01	2.00	1.96	2.03	1.94	1.96	2.00
Other Inputs	0.37	0.40	0.38	0.41	0.38	0.37	0.37	0.39	0.35	0.34	0.34	0.36	0.39	0.38	0.35
Crude Oil Product Supplied	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing Gain	0.94	0.94	0.95	0.94	0.90	0.93	0.94	0.91	0.88	0.94	0.95	0.92	0.94	0.92	0.92
Net Product Imports [c]	1.36	1.22	1.09	1.19	1.41	1.50	1.44	1.36	1.52	1.58	1.57	1.50	1.21	1.43	1.54
Product Stock Withdrawn or Added (-)	0.32	-0.62	-0.13	0.40	0.36	-0.54	-0.35	0.37	0.38	-0.56	-0.39	0.37	-0.01	-0.04	-0.05
Total Supply	19.12	19.29	19.84	19.95	19.80	19.76	20.09	20.34	20.16	20.21	20.60	20.72	19.55	20.00	20.43
Demand															
Motor Gasoline	8.03	8.49	8.58	8.39	8.16	8.65	8.70	8.58	8.28	8.79	8.88	8.78	8.37	8.52	8.68
Jet Fuel	1.64	1.67	1.78	1.72	1.75	1.74	1.80	1.82	1.80	1.77	1.83	1.85	1.70	1.78	1.81
Distillate Fuel Oil	3.76	3.56	3.61	3.89	4.02	3.68	3.62	3.86	4.08	3.74	3.69	3.93	3.70	3.80	3.86
Residual Fuel Oil	0.73	0.75	0.90	0.97	0.90	0.73	0.79	0.76	0.86	0.84	0.92	0.74	0.84	0.79	0.84
Other Oils [d]	4.96	4.82	4.97	4.97	4.97	4.95	5.18	5.32	5.14	5.08	5.29	5.42	4.93	5.11	5.23
Total Demand	19.12	19.29	19.84	19.93	19.80	19.76	20.09	20.34	20.16	20.21	20.60	20.72	19.55	20.00	20.43
Total Petroleum Net Imports	9.48	10.38	10.58	9.87	10.24	10.93	11.16	10.70	10.67	11.45	11.56	11.04	10.08	10.76	11.18
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	296	291	280	289	306	308	292	289	310	314	302	301	289	289	301
Total Motor Gasoline	205	210	197	197	204	203	197	202	206	206	200	205	197	202	205
Finished Motor Gasoline	158	165	154	157	157	162	156	161	160	164	159	163	157	161	163
Blending Components	47	45	43	40	46	42	41	41	46	42	41	41	40	41	41
Jet Fuel	41	44	42	45	41	42	44	44	41	42	43	44	45	44	44
Distillate Fuel Oil	96	106	115	114	85	97	115	117	88	101	124	125	114	117	125
Residual Fuel Oil	36	37	38	35	33	34	37	38	35	35	37	38	35	38	38
Other Oils [e]	235	272	288	253	249	285	300	258	255	291	307	265	253	258	265
Total Stocks (excluding SPR)	908	960	961	933	917	968	985	948	934	989	1012	979	933	948	979
Crude Oil in SPR	569	569	570	540	540	540	556	572	572	572	572	572	540	572	572
Heating Oil Reserve	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2
Total Stocks (including SPR)	1478	1529	1531	1473	1458	1509	1541	1520	1506	1561	1584	1550	1473	1520	1550

[a] Includes lease condensate.

[b] Net imports equals gross imports plus SPR imports minus exports.

[c] Includes finished petroleum products, unfinished oils, gasoline blending components, and natural gas plant liquids for processing

[d] Includes crude oil product supplied, natural gas liquids, liquefied refinery gas, other liquids, and all finished petroleum products except motor gasoline, jet fuel, distillate, and residual fuel oil.

[e] Includes stocks of all other oils, such as aviation gasoline, kerosene, natural gas liquids (including ethane), aviation gasoline blending components, naphtha and other oils for petrochemical feedstock use, special naphthas, lube oils, wax, coke, asphalt, road oil, and miscellaneous oils.

SPR: Strategic Petroleum Reserve

NGL: Natural Gas Liquids

Notes: Minor discrepancies with other EIA published historical data are due to rounding, with the following exception: recent petroleum demand and supply data displayed here reflect the incorporation of resubmissions of the data as reported in EIA's *Petroleum Supply Monthly*, Table C1. Historical data are printed in bold, forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

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Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109, and *Weekly Petroleum Status Report*, DOE/EIA-0208.

Table 6. Approximate Energy Demand Sensitivities[a] for the STIFS[b] Model

(Percent Deviation Base Case)

Demand Sector	+1% GDP	+ 10% Prices		+ 10% Weather[e]	
		Crude Oil[c]	N.Gas Wellhead[d]	Fall/Winter[f]	Spring/Summer[f]
Petroleum					
Total	0.6%	-0.3%	0.1%	1.1%	0.1%
Motor Gasoline	0.1%	-0.3%	0.0%	0.0%	0.0%
Distillate Fuel	0.8%	-0.2%	0.0%	2.7%	0.1%
Residual Fuel	1.6%	-3.4%	2.6%	2.0%	2.7%
Natural Gas					
Total	1.1%	0.3%	-0.4%	4.4%	1.0%
Residential	0.1%	0.0%	0.0%	8.2%	0.0%
Commercial	0.9%	0.0%	0.0%	7.3%	0.0%
Industrial	1.7%	0.2%	-0.5%	1.3%	0.0%
Electric Utility	1.8%	1.6%	-1.5%	1.0%	4.0%
Coal					
Total	0.7%	0.0%	0.0%	1.7%	1.7%
Electric Utility	0.6%	0.0%	0.0%	1.9%	1.9%
Electricity					
Total	0.6%	0.0%	0.0%	1.5%	1.7%
Residential	0.1%	0.0%	0.0%	3.2%	3.6%
Commercial	0.9%	0.0%	0.0%	1.0%	1.4%
Industrial	0.8%	0.0%	0.0%	0.3%	0.2%

[a]Percent change in demand quantity resulting from specified percent changes in model inputs.
[b]Short-Term Integrated Forecasting System.
[c]Refiner acquisitions cost of imported crude oil.
[d]Average unit value of marketed natural gas production reported by States.
[e]Refers to percent changes in degree-days.
[f]Response during fall/winter period(first and fourth calendar quarters) refers to change in heating degree-days. Response during the spring/summer period (second and third calendar quarters) refers to change in cooling degree-days.

Table 7. Forecast Components for U.S. Crude Oil Production

(Million Barrels per Day)

	High Price Case	Low Price Case	Difference		
			Total	Uncertainty	Price Impact
United States	*6.11*	*5.48*	*0.63*	*0.08*	*0.55*
Lower 48 States	*5.04*	*4.44*	*0.60*	*0.07*	*0.53*
Alaska	*1.07*	*1.03*	*0.04*	*0.02*	*0.02*

Note: Components provided are for the fourth quarter 2002. Totals may not add to sum of components due to independent rounding.
Source: Energy Information Administration, Office of Oil and Gas, Reserves and Natural Gas Division.

Table 8. U.S. Natural Gas Supply and Demand: Mid world Oil Price Case

(Trillion Cubic Feet)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Supply															
Total Dry Gas Production	**4.62**	**4.61**	**4.72**	*4.87*	*4.89*	*4.88*	*4.95*	*5.12*	*5.07*	*5.04*	*5.05*	*5.17*	*18.83*	*19.84*	*20.34*
Net Imports	**0.87**	**0.82**	**0.87**	*0.92*	*0.98*	*0.97*	*1.04*	*1.04*	*1.04*	*1.02*	*1.07*	*1.06*	*3.49*	*4.03*	*4.19*
Supplemental Gaseous Fuels	**0.03**	**0.02**	**0.02**	*0.03*	*0.04*	*-0.03*	*0.03*	*0.03*	*0.04*	*0.03*	*0.03*	*0.03*	*0.10*	*0.12*	*0.13*
Total New Supply	**5.52**	**5.46**	**5.62**	*5.82*	*5.91*	*5.88*	*6.01*	*6.20*	*6.15*	*6.09*	*6.15*	*6.27*	*22.42*	*24.00*	*24.65*
Working Gas in Storage															
Opening	**2.51**	**1.15**	**1.71**	*2.47*	*1.74*	*0.44*	*1.37*	*2.33*	*2.00*	*0.88*	*1.68*	*2.58*	*2.51*	*1.74*	*2.00*
Closing	**1.15**	**1.71**	**2.47**	*1.74*	*0.44*	*1.37*	*2.33*	*2.00*	*0.88*	*1.68*	*2.58*	*2.27*	*1.74*	*2.00*	*2.27*
Net Withdrawals	**1.36**	**-0.56**	**-0.77**	*0.73*	*1.30*	*-0.93*	*-0.96*	*0.33*	*1.12*	*-0.80*	*-0.90*	*0.31*	*0.77*	*-0.26*	*-0.26*
Total Supply	**6.88**	**4.90**	**4.85**	*6.55*	*7.21*	*4.95*	*5.05*	*6.52*	*7.27*	*5.29*	*5.25*	*6.58*	*23.19*	*23.74*	*24.39*
Balancing Item [a]	**0.05**	**0.07**	**-0.14**	*-0.48*	*0.06*	*0.15*	*-0.07*	*-0.54*	*0.15*	*0.01*	*-0.04*	*-0.54*	*-0.50*	*-0.39*	*-0.41*
Total Primary Supply	**6.93**	**4.98**	**4.71**	*6.07*	*7.28*	*5.11*	*4.98*	*5.99*	*7.42*	*5.31*	*5.21*	*6.05*	*22.69*	*23.35*	*23.98*
Demand															
Lease and Plant Fuel	**0.31**	**0.30**	**0.31**	*0.32*	*0.32*	*0.31*	*0.31*	*0.33*	*0.32*	*0.32*	*0.32*	*0.33*	*1.24*	*1.27*	*1.28*
Pipeline Use	**0.21**	**0.15**	**0.15**	*0.18*	*0.22*	*0.15*	*0.15*	*0.18*	*0.22*	*0.16*	*0.15*	*0.18*	*0.68*	*0.70*	*0.71*
Residential	**2.22**	**0.77**	**0.38**	*1.59*	*2.50*	*0.85*	*0.38*	*1.44*	*2.46*	*0.86*	*0.38*	*1.46*	*4.97*	*5.17*	*5.16*
Commercial	**1.29**	**0.64**	**0.47**	*0.99*	*1.44*	*0.64*	*0.45*	*0.92*	*1.43*	*0.66*	*0.46*	*0.94*	*3.38*	*3.46*	*3.49*
Industrial (Incl. Nonutility Use)	**2.35**	**2.29**	**2.34**	*2.40*	*2.38*	*2.34*	*2.55*	*2.49*	*2.52*	*2.47*	*2.70*	*2.61*	*9.38*	*9.76*	*10.31*
Electric Utilities	**0.56**	**0.83**	**1.06**	*0.59*	*0.42*	*0.80*	*1.15*	*0.63*	*0.46*	*0.84*	*1.20*	*0.53*	*3.04*	*2.99*	*3.03*
Total Demand	**6.93**	**4.98**	**4.71**	*6.07*	*7.28*	*5.11*	*4.98*	*5.99*	*7.42*	*5.31*	*5.21*	*6.05*	*22.69*	*23.35*	*23.98*

[a] The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

Notes: Minor discrepancies with other EIA published historical data are due to 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: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Oil and Gas, Reserves and Natural Gas Division.

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Table 9. U.S. Coal Supply and Demand: Mid World Oil Price Case

(Million Short Tons)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Supply															
Production	274.1	260.5	278.5	293.8	282.5	284.5	287.4	287.1	281.5	290.6	304.0	283.1	1106.9	1141.6	1159.2
Appalachia	109.5	105.3	108.1	108.6	111.1	112.9	102.6	103.7	108.8	113.0	105.9	100.1	431.5	430.3	427.8
Interior	36.1	35.2	41.3	39.8	35.4	36.8	40.8	36.8	33.5	35.8	41.2	34.5	152.4	149.7	145.1
Western	128.5	120.0	129.1	145.3	136.0	134.9	144.0	146.6	139.1	141.8	156.8	148.6	522.9	561.6	586.4
Primary Stock Levels [a]															
Opening	39.5	44.4	40.4	37.1	34.2	41.3	40.2	36.5	34.9	40.8	41.0	36.2	39.5	34.2	34.9
Closing	44.4	40.4	37.1	34.2	41.3	40.2	36.5	34.9	40.8	41.0	36.2	35.2	34.2	34.9	35.2
Net Withdrawals	-4.9	4.0	3.3	2.9	-7.1	1.1	3.7	1.6	-6.0	-0.2	4.8	1.0	5.3	-0.7	-0.3
Imports	2.8	2.7	3.6	2.6	3.0	2.9	2.9	3.0	3.0	3.0	3.0	3.0	11.7	11.8	12.0
Exports	13.6	14.4	15.8	15.2	14.9	15.1	15.3	15.2	15.3	15.4	15.7	15.6	58.9	60.5	62.0
Total Net Domestic Supply	258.3	252.8	289.6	284.1	263.5	273.5	278.8	276.5	263.3	278.0	296.1	271.5	1064.9	1092.3	1108.9
Secondary Stock Levels [b]															
Opening	143.5	140.4	136.3	119.2	124.6	117.2	131.1	116.2	124.6	111.7	118.3	105.7	143.5	124.6	124.6
Closing	140.4	136.3	119.2	124.6	117.2	131.1	116.2	124.6	111.7	118.3	105.7	113.0	124.6	124.6	113.0
Net Withdrawals	3.1	4.1	17.2	-5.5	7.5	-14.0	15.0	-8.4	12.9	-6.6	12.6	-7.3	18.9	0.1	11.6
Waste Coal Supplied to IPPs [c]	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	12.2	12.2	12.2
Total Supply	264.5	260.0	289.8	281.7	274.0	262.6	296.9	271.1	279.2	274.4	311.8	267.3	1096.0	1104.6	1132.7
Demand															
Coke Plants	7.3	7.2	7.2	7.3	7.2	7.2	7.1	7.1	7.1	7.2	7.2	7.3	28.9	28.6	28.7
Electricity Production															
Electric Utilities	214.1	202.1	227.3	214.8	215.4	207.4	237.3	210.4	220.2	218.8	251.5	205.8	858.2	870.5	896.3
Nonutilities (Excl. Cogen.) [d]	25.3	24.7	28.0	26.7	32.9	31.0	35.5	33.9	33.5	31.5	36.2	34.5	104.7	133.3	135.8
Retail and General Industry	18.1	16.7	17.1	19.6	18.5	17.0	17.0	19.7	18.4	16.9	16.9	19.7	71.5	72.2	71.9
Total Demand [e]	264.8	250.7	279.6	268.4	274.0	262.6	296.9	271.1	279.2	274.4	311.8	267.3	1063.4	1104.6	1132.7
Discrepancy [f]	-0.3	9.3	10.2	13.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.6	0.0	0.0

[a] Primary stocks are held at the mines, preparation plants, and distribution points.

[b] Secondary stocks are held by users. It includes an estimate of stocks held at utility plants sold to nonutility generators.

[c] Estimated independent power producers' (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes.

[d] Estimates of coal consumption by IPPs, supplied by the Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration (EIA). Quarterly coal consumption estimates for 1999 and projections for 2000 and 2001 are based on (1) estimated consumption by utility power plants sold to nonutility generators during 1998 and 1999, and (2) annual coal-fired generation at nonutilities from Form EIA-867 (Annual Nonutility Power Producer Report).

[e] Total Demand includes estimated IPP consumption.

[f] The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period.

Notes: Rows and columns may not add 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: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Quarterly Coal Report*, DOE/EIA-0121, and *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table 10. U.S. Electricity Supply and Demand: Mid World Oil Price Case

(Billion Kilowatt-hours)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Supply															
Net Utility Generation															
Coal	**425.7**	**401.2**	**445.9**	*427.0*	*435.4*	*417.7*	*477.4*	*420.4*	*435.8*	*435.3*	*498.6*	*401.3*	*1699.8*	*1750.9*	*1771.0*
Petroleum	**11.0**	**16.4**	**23.3**	*14.5*	*23.2*	*17.1*	*24.4*	*17.2*	*21.9*	*23.7*	*32.1*	*16.6*	*65.1*	*81.9*	*94.3*
Natural Gas	**54.4**	**79.1**	**100.5**	*55.5*	*39.6*	*76.1*	*108.7*	*59.4*	*43.7*	*80.0*	*113.8*	*49.9*	*289.5*	*283.8*	*287.4*
Nuclear	**185.0**	**177.4**	**182.0**	*163.3*	*173.7*	*165.9*	*175.2*	*159.7*	*167.5*	*153.0*	*179.3*	*163.5*	*707.6*	*674.6*	*663.3*
Hydroelectric	**66.9**	**73.0**	**57.4**	*61.3*	*67.8*	*73.3*	*60.5*	*60.4*	*71.4*	*75.2*	*63.1*	*62.3*	*258.6*	*262.0*	*272.0*
Geothermal and Other [a]	**0.5**	**0.6**	**0.5**	*0.6*	*0.5*	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*	*0.6*	*2.2*	*2.2*	*2.2*
Subtotal	**743.4**	**747.6**	**809.6**	*722.2*	*740.2*	*750.6*	*846.9*	*717.7*	*740.9*	*767.8*	*887.5*	*694.0*	*3022.8*	*3055.3*	*3090.2*
Nonutility Generation [b]															
Coal	**55.2**	**58.5**	**82.1**	*60.5*	*59.1*	*59.2*	*69.3*	*59.0*	*60.9*	*61.6*	*61.6*	*71.3*	*256.2*	*246.7*	*255.4*
Petroleum	**11.1**	**8.8**	**11.7**	*9.9*	*9.7*	*9.7*	*11.3*	*9.6*	*10.0*	*10.1*	*10.1*	*11.7*	*41.4*	*40.4*	*41.8*
Natural Gas	**66.9**	**76.0**	**98.0**	*76.1*	*73.0*	*83.5*	*114.4*	*90.1*	*84.1*	*83.5*	*95.2*	*128.9*	*317.0*	*361.1*	*391.7*
Other Gaseous Fuels [c]	**2.5**	**2.8**	**3.6**	*2.3*	*2.1*	*2.1*	*2.1*	*2.2*	*2.3*	*2.2*	*2.2*	*2.2*	*11.1*	*8.5*	*8.9*
Nuclear	**5.2**	**5.0**	**16.7**	*20.2*	*21.5*	*20.5*	*21.7*	*19.7*	*20.7*	*18.9*	*22.2*	*20.2*	*47.1*	*83.4*	*82.0*
Hydroelectric	**3.9**	**5.0**	**4.2**	*4.5*	*4.5*	*4.5*	*4.5*	*4.5*	*4.5*	*4.5*	*4.5*	*4.5*	*17.7*	*18.0*	*18.0*
Geothermal and Other [d]	**21.8**	**22.2**	**23.4**	*23.3*	*22.1*	*22.0*	*22.3*	*22.7*	*22.1*	*22.0*	*22.3*	*22.7*	*90.7*	*89.1*	*89.1*
Subtotal	**166.6**	**178.3**	**239.7**	*196.7*	*192.0*	*201.6*	*245.6*	*207.9*	*204.6*	*202.7*	*218.0*	*261.4*	*781.2*	*847.1*	*886.7*
Total Generation	**910.0**	**925.9**	**1049.2**	*918.9*	*932.2*	*952.2*	*1092.5*	*925.5*	*945.5*	*970.5*	*1105.5*	*955.4*	*3804.1*	*3902.4*	*3976.9*
Net Imports [e]	**9.2**	**8.7**	**13.1**	*8.3*	*7.7*	*8.8*	*12.0*	*8.6*	*7.3*	*8.3*	*11.7*	*8.6*	*39.3*	*37.2*	*35.9*
Total Supply	**919.2**	**934.6**	**1062.3**	*927.2*	*939.9*	*961.0*	*1104.5*	*934.2*	*952.8*	*978.8*	*1117.2*	*964.0*	*3843.3*	*3939.6*	*4012.8*
Losses and Unaccounted for [f]	**60.3**	**73.3**	**41.1**	*65.4*	*55.9*	*84.1*	*68.1*	*66.7*	*56.7*	*86.0*	*69.6*	*68.1*	*240.1*	*274.9*	*280.3*
Demand															
Electric Utility Sales															
Residential	**292.5**	**264.2**	**352.8**	*274.4*	*309.2*	*273.1*	*361.0*	*272.0*	*310.6*	*279.9*	*369.6*	*277.5*	*1183.9*	*1215.3*	*1237.6*
Commercial	**236.2**	**254.3**	**294.4**	*243.4*	*241.3*	*255.5*	*300.8*	*244.7*	*244.2*	*259.8*	*306.2*	*249.5*	*1028.2*	*1042.3*	*1059.7*
Industrial	**260.0**	**268.5**	**280.5**	*265.0*	*256.8*	*269.0*	*280.8*	*270.3*	*263.1*	*274.9*	*286.5*	*275.7*	*1074.0*	*1076.8*	*1100.3*
Other	**26.4**	**27.4**	**30.6**	*27.3*	*27.0*	*27.3*	*30.5*	*27.6*	*27.5*	*27.8*	*31.3*	*28.3*	*111.6*	*112.4*	*114.9*
Subtotal	**815.1**	**814.3**	**958.2**	*810.1*	*834.2*	*824.9*	*973.1*	*814.5*	*845.3*	*842.5*	*993.5*	*831.0*	*3397.7*	*3446.8*	*3512.4*
Nonutility Use/Sales [e]	**43.8**	**46.9**	**63.1**	*51.8*	*49.7*	*52.0*	*63.2*	*52.9*	*50.8*	*50.3*	*54.1*	*64.9*	*205.5*	*217.8*	*220.2*
Total Demand	**858.9**	**861.2**	**1021.3**	*861.9*	*884.0*	*876.9*	*1036.4*	*867.4*	*896.1*	*892.9*	*1047.7*	*895.9*	*3603.3*	*3664.7*	*3732.6*
Memo:															
Nonutility Sales to Electric Utilities [b]	**122.8**	**131.4**	**176.6**	**144.9**	**142.3**	**149.6**	*182.4*	*155.0*	*153.8*	*152.4*	*163.9*	*196.5*	*575.7*	*629.2*	*666.5*

[a] "Other" includes generation from wind, wood, waste, and solar sources.

[b] Electricity(net Generation) from nonutility sources, including cogenerators and small power producers.

[c] Includes refinery still gas and other process or waste gases and liquefied petroleum gases.

[d] Includes geothermal, solar, wind, wood, waste, hydrogen, sulfur, batteries, chemicals and spent sulfite liquor.

[e] Data for 1999 are estimates.

[f] Balancing item, mainly transmission and distribution losses.

[g] 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 1999 are estimates.

Notes: Minor discrepancies with other EIA published historical data are due to 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: Energy Information Administration; latest data available from EIA databases supporting the following report: *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table 11. U.S. Renewable Energy Use by Sector: Mid World Oil Price Case

(Quadrillion Btu)

	Year				Annual Percentage Change		
	1999	2000	2001	2002	1999-2000	2000-2001	2001-2002
Electric Utilities							
Hydroelectric Power [a]	**3.079**	*2.709*	*2.745*	*2.849*	*-12.0*	*1.3*	*3.8*
Geothermal, Solar and Wind Energy [b]	**0.036**	*0.003*	*0.004*	*0.004*	*-91.7*	*33.3*	*0.0*
Biofuels [c]	**0.021**	*0.021*	*0.021*	*0.021*	*0.0*	*0.0*	*0.0*
Total	**3.136**	*2.733*	*2.769*	*2.874*	*-12.9*	*1.3*	*3.8*
Nonutility Power Generators							
Hydroelectric Power [a]	**0.149**	*0.183*	*0.186*	*0.186*	*22.8*	*1.6*	*0.0*
Geothermal, Solar and Wind Energy [b]	**0.373**	*0.338*	*0.333*	*0.333*	*-9.4*	*-1.5*	*0.0*
Biofuels [c]	**0.523**	*0.741*	*0.729*	*0.729*	*41.7*	*-1.6*	*0.0*
Total	**1.045**	*1.262*	*1.249*	*1.249*	*20.8*	*-1.0*	*0.0*
Total Power Generation	**4.180**	*3.995*	*4.017*	*4.122*	*-4.4*	*0.6*	*2.6*
Other Sectors [d]							
Residential and Commercial [e]	**0.553**	*0.576*	*0.547*	*0.577*	*4.2*	*-5.0*	*5.5*
Industrial [f]	**1.942**	*2.003*	*2.008*	*2.058*	*3.1*	*0.2*	*2.5*
Transportation [g]	**0.100**	*0.110*	*0.111*	*0.117*	*10.0*	*0.9*	*5.4*
Total	**2.595**	*2.688*	*2.666*	*2.751*	*3.6*	*-0.8*	*3.2*
Net Imported Electricity [h]	**0.249**	*0.320*	*0.302*	*0.292*	*28.5*	*-5.6*	*-3.3*
Total Renewable Energy Demand	**7.023**	*7.003*	*6.986*	*7.165*	*-0.3*	*-0.2*	*2.6*

[a] Conventional hydroelectric power only. Hydroelectricity generated by pumped storage is not included in renewable energy.

[b] Also includes photovoltaic and solar thermal energy. Sharp declines since 1998 in the electric utility sector and corresponding increases in the nonutility sector for this category mostly reflect sale of geothermal facilities to the nonutility sector.

[c] Biofuels are fuelwood, wood byproducts, waste wood, municipal solid waste, manufacturing process waste, and alcohol fuels.

[d] 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.

[e] Includes biofuels and solar energy consumed in the residential and commercial sectors.

[f] onsists primarily of biofuels for use other than in electricity cogeneration.

[g] Ethanol blended into gasoline.

[h] Represents 78.6 percent of total electricity net imports, which is the proportion of total 1994 net imported electricity (0.459 quadrillion Btu) attributable to renewable sources (0.361 quadrillion Btu).

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.

Table A1. Annual U.S. Energy Supply and Demand

	Year														
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Real Gross Domestic Product (GDP) (billion chained 1996 dollars)	6368	6592	6708	6676	6880	7063	7348	7544	7813	8159	8516	8876	*9334*	*9634*	*10033*
Imported Crude Oil Price [a] (nominal dollars per barrel)	14.57	18.08	21.75	18.70	18.20	16.14	15.52	17.14	20.61	18.50	12.08	17.22	*27.86*	*26.92*	*21.28*
Petroleum Supply															
Crude Oil Production [b] (million barrels per day)	8.14	7.61	7.36	7.42	7.17	6.85	6.66	6.56	6.46	6.45	6.25	5.88	*5.84*	*5.89*	*5.84*
Total Petroleum Net Imports (including SPR) (million barrels per day)	6.59	7.20	7.16	6.63	6.94	7.62	8.05	7.89	8.50	9.16	9.76	9.91	*10.08*	*10.76*	*11.18*
Energy Demand															
World Petroleum (million barrels per day)	64.8	65.9	66.0	66.6	66.8	67.0	68.3	69.9	71.4	73.1	73.6	74.8	*74.8*	*75.9*	*77.9*
U.S. Petroleum (million barrels per day)	17.34	17.37	17.04	16.77	17.10	17.24	17.72	17.72	18.31	18.62	18.92	19.52	*19.55*	*20.00*	*20.43*
Natural Gas (trillion cubic feet)	18.03	18.80	18.72	19.03	19.54	20.28	20.71	21.58	21.96	21.95	21.26	21.70	*22.69*	*23.35*	*23.98*
Coal (million short tons)	877	891	897	898	907	943	950	962	1006	1029	1039	1044	*1063*	*1105*	*1133*
Electricity (billion kilowatthours)															
Utility Sales [c]	2578	2647	2713	2762	2763	2861	2935	3013	3098	3140	3240	3236	*3398*	*3447*	*3512*
Nonutility Own Use [d]	NA	91	113	119	122	127	138	145	145	148	156	185	*206*	*218*	*220*
Total	NA	2738	2826	2881	2885	2988	3073	3159	3243	3288	3396	3421	3603	3665	3733
Total Energy Demand [e] (quadrillion Btu)	NA	84.2	84.2	84.5	85.6	87.4	89.2	90.9	93.9	94.2	95.2	97.1	*98.3*	*100.2*	*102.3*
Total Energy Demand per Dollar of GDP (thousand Btu per 1996 Dollar)	NA	12.77	12.55	12.66	12.44	12.37	12.14	12.07	12.02	11.54	11.18	10.94	*10.53*	*10.40*	*10.20*

[a] Refers to the imported cost of crude oil to U.S. refiners.

[b] Includes lease condensate.

[c] Total annual electric utility sales for historical periods are derived from the sum of monthly sales figures based on submissions by electric utilities of Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions." These historical values differ from annual sales totals based on *Form EIA-861*, reported in several EIA publications, but match alternate annual totals reported in EIA's *Electric Power Monthly*, DOE/EIA-0226.

[d] 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 1999 are estimates.

[e] "Total Energy Demand" refers to the aggregate energy concept presented in Energy Information Administration, *Annual Energy Review*, 1997, DOE/EIA-0384(97) (AER), Table 1.1. Prior to 1990, some components of renewable energy consumption, particularly relating to consumption at nonutility electric generating facilities, were not available. For those years, a less compehensive measure of total energy demand can be found in EIA's *AER*. The conversion from physical units to Btu is calculated 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 *AER*.

Notes: SPR: Strategic Petroleum Reserve. 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; 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; *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-520, and Weekly Petroleum *Status Report* DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL1200.

Table A2. Annual U.S. Macroeconomic and Weather Indicators

	Year														
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Macroeconomic															
Real Gross Domestic Product (billion chained 1996 dollars)	6368	6592	6708	6676	6880	7063	7348	7544	7813	8159	8516	8876	9334	9634	10033
GDP Implicit Price Deflator (Index, 1996=1.000)	0.802	0.833	0.865	0.897	0.919	0.941	0.960	0.981	1.000	1.020	1.032	1.048	1.071	1.094	1.114
Real Disposable Personal Income (billion chained 1996 Dollars)	4784	4907	5014	5033	5189	5261	5397	5539	5678	5854	6134	6331	6512	6771	7099
Manufacturing Production (Index, 1996=1.000)	0.801	0.816	0.812	0.793	0.825	0.855	0.907	0.955	1.000	1.070	1.123	1.170	1.242	1.290	1.330
Real Fixed Investment (billion chained 1996 dollars)	887	911	895	833	886	958	1046	1109	1213	1329	1485	1621	1779	1860	1942
Real Exchange Rate (Index, 1996=1.000)	NA	NA	0.963	0.966	0.960	1.001	0.981	0.927	1.000	1.102	1.122	1.118	1.224	1.262	1.192
Business Inventory Change (billion chained 1996 dollars)	17.0	14.2	8.9	-6.8	-4.7	3.6	12.1	14.1	10.1	15.2	25.6	0.1	15.8	5.7	6.0
Producer Price Index (index, 1982=1.000)	1.069	1.122	1.163	1.165	1.172	1.189	1.205	1.247	1.277	1.275	1.244	1.255	1.327	1.346	1.347
Consumer Price Index (index, 1982-1984=1.000)	1.184	1.240	1.308	1.363	1.404	1.446	1.483	1.525	1.570	1.606	1.631	1.667	1.724	1.765	1.798
Petroleum Product Price Index (index, 1982=1.000)	0.539	0.612	0.748	0.671	0.647	0.620	0.591	0.608	0.701	0.680	0.513	0.609	0.909	0.886	0.741
Non-Farm Employment (millions)	105.2	107.9	109.4	108.3	108.6	110.7	114.1	117.2	119.6	122.7	125.8	128.8	131.5	132.7	134.1
Commercial Employment (millions)	67.8	70.0	71.3	70.8	71.2	73.2	76.1	78.8	81.1	83.9	86.6	89.5	91.9	93.4	95.2
Total Industrial Production (index, 1996=1.000)	0.815	0.830	0.828	0.812	0.837	0.866	0.914	0.958	1.000	1.063	1.108	1.147	1.212	1.253	1.289
Housing Stock (millions)	101.8	102.9	103.5	104.5	105.5	106.8	108.2	109.6	111.0	112.5	114.1	115.7	116.1	117.4	118.6
Weather [a]															
Heating Degree-Days															
U.S.	4653	4726	4016	4200	4441	4700	4483	4531	4713	4542	3951	4169	4458	4463	4459
New England	6715	6887	5848	5960	6844	6728	6672	6559	6679	6662	5680	5952	6499	6467	6462
Middle Atlantic	6088	6134	4998	5177	5964	5948	5934	5831	5986	5809	4812	5351	5725	5703	5698
U.S. Gas-Weighted	4804	4856	4139	4337	4458	4754	4659	4707	4980	4802	4183	4399	4683	4714	4710
Cooling Degree-Days (U.S.)	1283	1156	1260	1331	1040	1218	1220	1293	1180	1156	1410	1297	1252	1235	1237

[a] Population-weighted degree-days. A degree-day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population.

Notes: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release G 17(419)*; U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL1200.

Table A3. Annual International Petroleum Supply and Demand Balance

(Millions Barrels per Day, Except OECD Commercial Stocks)

	Year														
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Demand [a]															
OECD															
U.S. (50 States)	17.3	17.3	17.0	16.7	17.0	17.2	17.7	17.7	18.3	18.6	18.9	19.5	*19.5*	*20.0*	*20.4*
Europe [b]	12.4	12.5	12.6	13.4	13.6	13.5	13.6	14.1	14.3	14.4	14.7	14.5	*14.5*	*14.7*	*14.8*
Japan	4.8	5.0	5.1	5.3	5.4	5.4	5.7	5.7	5.9	5.7	5.5	5.6	*5.6*	*5.6*	*5.6*
Other OECD	2.8	2.7	2.7	2.7	2.7	2.8	2.9	3.0	3.0	3.1	3.1	3.3	*3.3*	*3.4*	*3.6*
Total OECD	37.1	37.6	37.5	38.1	38.8	39.0	39.9	40.6	41.4	41.8	42.3	42.9	*42.9*	*43.7*	*44.4*
Non-OECD															
Former Soviet Union	8.9	8.7	8.4	8.3	6.8	5.6	4.8	4.6	4.0	3.9	3.8	3.6	*3.7*	*3.7*	*3.8*
Europe	2.2	2.1	1.9	1.4	1.3	1.3	1.3	1.3	1.4	1.5	1.5	1.6	*1.6*	*1.7*	*1.7*
China	2.3	2.4	2.3	2.5	2.7	3.0	3.2	3.4	3.6	3.9	4.1	4.3	*4.5*	*4.8*	*5.0*
Other Asia	4.4	4.9	5.3	5.7	6.2	6.8	7.3	7.9	8.5	9.0	8.7	8.8	*9.2*	*9.7*	*10.2*
Other Non-OECD	10.0	10.3	10.5	10.6	11.0	11.4	11.8	12.1	12.4	13.0	13.3	13.6	*14.0*	*14.4*	*14.8*
Total Non-OECD	27.7	28.3	28.5	28.5	28.0	28.0	28.4	29.3	30.0	31.3	31.3	31.9	*33.0*	*34.2*	*35.5*
Total World Demand	64.8	65.9	66.0	66.6	66.8	67.0	68.3	69.9	71.4	73.1	73.6	74.8	*75.9*	*77.9*	*79.9*
Supply [c]															
OECD															
U.S. (50 States)	10.5	9.9	9.7	9.9	9.8	9.6	9.4	9.4	9.4	9.5	9.3	9.0	*9.1*	*9.2*	*9.1*
Canada	2.0	2.0	2.0	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.6	*2.7*	*2.8*	*2.9*
North Sea [d]	3.8	3.7	3.9	4.1	4.5	4.8	5.5	5.9	6.3	6.2	6.2	6.3	*6.4*	*6.4*	*6.4*
Other OECD	1.5	1.4	1.5	1.5	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.5	*1.7*	*1.7*	*1.7*
Total OECD	17.8	17.1	17.1	17.5	17.9	18.0	18.7	19.2	19.7	19.9	19.7	19.4	*19.9*	*20.1*	*20.1*
Non-OECD															
OPEC	21.5	23.3	24.5	24.6	25.8	26.6	27.0	27.6	28.3	29.9	30.4	29.3	*30.8*	*31.4*	*32.5*
Former Soviet Union	12.5	12.1	11.4	10.4	8.9	8.0	7.3	7.1	7.1	7.1	7.2	7.4	*7.8*	*8.2*	*8.5*
China	2.7	2.8	2.8	2.8	2.8	2.9	2.9	3.0	3.1	3.2	3.2	3.2	*3.3*	*3.2*	*3.1*
Mexico	2.9	2.9	3.0	3.2	3.2	3.2	3.2	3.1	3.3	3.4	3.5	3.4	*3.6*	*3.8*	*4.0*
Other Non-OECD	7.3	12.0	8.0	8.1	8.4	8.7	9.2	9.9	10.2	10.5	10.8	11.2	*11.3*	*11.3*	*11.6*
Total Non-OECD	47.0	48.8	49.7	49.1	49.1	49.4	49.6	50.7	52.0	54.2	55.2	54.5	*56.7*	*57.8*	*59.7*
Total World Supply	64.8	65.9	66.8	66.7	67.0	67.4	68.3	69.9	71.8	74.1	74.9	73.9	*76.6*	*78.0*	*79.8*
Total Stock Withdrawals	0.1	0.0	-0.8	-0.1	-0.3	-0.4	0.0	0.0	-0.4	-1.0	-1.3	0.9	*-0.7*	*0.0*	*0.1*
OECD Comm. Stocks, End (bill. bbls.)	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.7	2.7	2.7	2.8	2.6	2.6	2.6	2.8
Net Exports from Former Soviet Union	3.6	3.4	3.0	2.1	2.1	2.3	2.4	2.6	3.0	3.3	3.5	3.8	*4.2*	*4.5*	*4.7*

[a] Demand for petroleum by the OECD countries is synonymous with "petroleum product supplied," which is defined in the glossary of the EIA *Petroleum Supply Monthly*, DOE/EIA-0109. Demand for petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

[b] OECD Europe includes the former East Germany.

[c] Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources.

[d] Includes offshore supply from Denmark, Germany, the Netherlands, Norway, and the United Kingdom.

OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

OPEC: Organization of Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

SPR: Strategic Petroleum Reserve

Former Soviet Union: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Notes: Minor discrepancies with other published EIA historical data are due to 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: Energy Information Administration: latest data available from EIA databases supporting the following reports: *International Petroleum Statistics Report*, DOE/EIA-0520, and Organization for Economic Cooperation and Development, Annual and Monthly Oil Statistics Database.

Table A4. Annual Average U. S. Energy Prices
(Nominal Dollars)

	Year														
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Imported Crude Oil Prices															
Imported Average[a]	14.57	18.08	21.75	18.70	18.20	16.14	15.52	17.14	20.61	18.50	12.08	17.22	27.86	26.92	21.28
WTI[b] Spot Average	15.98	19.78	24.48	21.60	20.54	18.49	17.16	18.41	22.11	20.61	14.45	19.25	30.29	28.96	23.32
Natural Gas Wellhead															
(dollars per thousand cubic feet)	1.69	1.69	1.71	1.64	1.74	2.04	1.85	1.55	2.17	2.32	1.95	2.17	3.73	5.22	4.57
Petroleum Products															
Gasoline Retail[c] (dollars per gallon)															
All Grades	0.92	1.02	1.17	1.15	1.14	1.13	1.13	1.16	1.25	1.24	1.07	1.18	1.53	1.48	1.33
Regular Unleaded	0.91	0.99	1.13	1.10	1.09	1.07	1.08	1.11	1.20	1.20	1.03	1.14	1.49	1.44	1.30
No. 2 Diesel Oil, Retail (dollars per gallon)	0.91	0.99	1.16	1.12	1.10	1.11	1.11	1.10	1.22	1.19	1.04	1.12	1.48	1.51	1.33
No. 2 Heating Oil, Wholesale (dollars per gallon)	0.47	0.56	0.70	0.62	0.58	0.54	0.51	0.51	0.64	0.59	0.42	0.51	0.89	0.87	0.69
No. 2 Heating Oil, Retail (dollars per gallon)	0.81	0.90	1.06	1.02	0.93	0.91	0.88	0.87	0.99	0.99	0.85	0.88	1.33	1.37	1.14
No. 6 Residual Fuel Oil, Retail[d] (dollars per barrel)	14.04	16.20	18.66	14.32	14.21	14.00	14.79	16.49	19.01	17.82	12.83	16.02	25.93	25.85	20.80
Electric Utility Fuels															
Coal (dollars per million Btu)	1.47	1.44	1.45	1.45	1.41	1.38	1.36	1.32	1.29	1.27	1.25	1.22	1.20	1.20	1.19
Heavy Fuel Oil[e] (dollars per million Btu)	2.41	2.85	3.22	2.49	2.46	2.36	2.40	2.60	3.01	2.79	2.07	2.39	4.23	4.17	3.36
Natural Gas (dollars per million Btu)	2.26	2.36	2.32	2.15	2.33	2.56	2.23	1.98	2.64	2.76	2.38	2.57	4.28	5.53	4.99
Other Residential															
Natural Gas (dollars per thousand cubic feet)	5.47	5.64	5.80	5.82	5.89	6.17	6.41	6.06	6.35	6.95	6.83	6.69	7.73	9.83	9.42
Electricity (cents per kilowatthour)	7.49	7.64	7.85	8.05	8.23	8.34	8.40	8.40	8.36	8.43	8.26	8.16	8.21	8.34	8.43

[a]Refiner acquisition cost (RAC) of imported crude oil.
[b]West Texas Intermediate.
[c]Average self-service cash prices.
[d]Average for all sulfur contents.
[e]Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data. Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Table A5. Annual U.S. Petroleum Supply and Demand
(Million Barrels per Day, Except Closing Stocks)

	Year														
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Supply															
Crude Oil Supply															
Domestic Production [a]	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	**6.25**	**5.88**	*5.84*	*5.89*	*5.84*
Alaska	**2.02**	**1.87**	**1.77**	**1.80**	**1.71**	**1.58**	**1.56**	**1.48**	**1.39**	**1.30**	**1.17**	**1.05**	*0.97*	*1.02*	*1.05*
Lower 48	**6.12**	**5.74**	**5.58**	**5.62**	**5.46**	**5.26**	**5.10**	**5.08**	**5.07**	**5.16**	**5.08**	**4.83**	*4.87*	*4.87*	*4.79*
Net Imports (including SPR) [b]	**4.95**	**5.70**	**5.79**	**5.67**	**5.99**	**6.69**	**6.96**	**7.14**	**7.40**	**8.12**	**8.60**	**8.61**	*8.86*	*9.33*	*9.64*
Other SPR Supply	**0.00**	**0.00**	**0.00**	**0.00**	**0.01**	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**	**0.02**	**0.01**	*0.08*	*0.09*	*0.00*
Stock Draw (Including SPR)	**0.00**	**-0.09**	**0.02**	**-0.01**	**0.00**	**-0.08**	**-0.02**	**0.09**	**0.05**	**-0.06**	**-0.07**	**0.09**	*-0.02*	*0.00*	*-0.03*
Product Supplied and Losses	**-0.04**	**-0.03**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**0.00**	**0.00**	**0.00**	*0.00*	*0.00*	*0.00*
Unaccounted-for Crude Oil	**0.20**	**0.20**	**0.26**	**0.20**	**0.26**	**0.17**	**0.27**	**0.19**	**0.22**	**0.14**	**0.11**	**0.19**	*0.31*	*0.21*	*0.22*
Total Crude Oil Supply	**13.25**	**13.40**	**13.41**	**13.30**	**13.41**	**13.61**	**13.87**	**13.97**	**14.19**	**14.66**	**14.89**	**14.80**	*15.08*	*15.35*	*15.67*
Other Supply															
NGL Production	**1.62**	**1.55**	**1.56**	**1.66**	**1.70**	**1.74**	**1.73**	**1.76**	**1.83**	**1.82**	**1.76**	**1.85**	*1.94*	*1.96*	*2.00*
Other Inputs	**0.11**	**0.11**	**0.13**	**0.15**	**0.20**	**0.25**	**0.26**	**0.30**	**0.31**	**0.34**	**0.38**	**0.38**	*0.39*	*0.38*	*0.35*
Crude Oil Product Supplied	**0.04**	**0.03**	**0.02**	**0.02**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.00**	**0.00**	**0.00**	*0.00*	*0.00*	*0.00*
Processing Gain	**0.66**	**0.66**	**0.68**	**0.71**	**0.77**	**0.77**	**0.77**	**0.77**	**0.84**	**0.85**	**0.89**	**0.89**	*0.94*	*0.92*	*0.92*
Net Product Imports [c]	**1.63**	**1.50**	**1.38**	**0.96**	**0.94**	**0.93**	**1.09**	**0.75**	**1.10**	**1.04**	**1.17**	**1.30**	*1.21*	*1.43*	*1.54*
Product Stock Withdrawn	**0.03**	**0.13**	**-0.14**	**-0.04**	**0.06**	**-0.05**	**0.00**	**0.15**	**0.03**	**-0.09**	**-0.17**	**0.30**	*-0.01*	*-0.04*	*-0.05*
Total Supply	**17.33**	**17.37**	**17.04**	**16.76**	**17.10**	**17.28**	**17.72**	**17.72**	**18.31**	**18.62**	**18.92**	**19.52**	*19.55*	*20.00*	*20.43*
Demand															
Motor Gasoline [d]	**7.36**	**7.40**	**7.31**	**7.23**	**7.38**	**7.48**	**7.60**	**7.79**	**7.89**	**8.02**	**8.25**	**8.43**	*8.37*	*8.52*	*8.68*
Jet Fuel	**1.45**	**1.49**	**1.52**	**1.47**	**1.45**	**1.47**	**1.53**	**1.51**	**1.58**	**1.60**	**1.62**	**1.67**	*1.70*	*1.78*	*1.81*
Distillate Fuel Oil	**3.12**	**3.16**	**3.02**	**2.92**	**2.98**	**3.04**	**3.16**	**3.21**	**3.37**	**3.44**	**3.46**	**3.57**	*3.70*	*3.80*	*3.86*
Residual Fuel Oil	**1.38**	**1.37**	**1.23**	**1.16**	**1.09**	**1.08**	**1.02**	**0.85**	**0.85**	**0.80**	**0.89**	**0.83**	*0.84*	*0.79*	*0.84*
Other Oils [e]	**4.03**	**3.95**	**3.95**	**3.99**	**4.20**	**4.17**	**4.41**	**4.36**	**4.63**	**4.77**	**4.69**	**5.01**	*4.93*	*5.11*	*5.23*
Total Demand	**17.34**	**17.37**	**17.04**	**16.77**	**17.10**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	**18.92**	**19.52**	*19.55*	*20.00*	*20.43*
Total Petroleum Net Imports	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	**9.76**	**9.91**	*10.08*	*10.76*	*11.18*
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	**330**	**341**	**323**	**325**	**318**	**335**	**337**	**303**	**284**	**305**	**324**	**284**	*289*	*289*	*301*
Total Motor Gasoline	**228**	**213**	**220**	**219**	**216**	**226**	**215**	**202**	**195**	**210**	**218**	**193**	*197*	*202*	*205*
Jet Fuel	**44**	**41**	**52**	**49**	**43**	**40**	**47**	**40**	**40**	**44**	**45**	**41**	*45*	*44*	*44*
Distillate Fuel Oil	**124**	**106**	**132**	**144**	**141**	**141**	**145**	**130**	**127**	**138**	**156**	**125**	*114*	*117*	*125*
Residual Fuel Oil	**45**	**44**	**49**	**50**	**43**	**44**	**42**	**37**	**46**	**40**	**45**	**36**	*35*	*38*	*38*
Other Oils [f]	**267**	**257**	**261**	**267**	**263**	**273**	**275**	**258**	**250**	**259**	**291**	**246**	*253*	*258*	*265*

[a] Includes lease condensate.
[b] Net imports equals gross imports plus SPR imports minus exports.
[c] Includes finished petroleum products, unfinished oils, gasoline blending components, and natural gas plant liquids for processing.
[d] For years prior to 1993, motor gasoline includes an estimate of fuel ethanol blended into gasoline and certain product reclassifications, not reported elsewhere in EIA. See Appendix B in Energy Information Administration, *Short-Term Energy Outlook*, EIA/DOE-0202(93/3Q), for details on this adjustment.
[e] Includes crude oil product supplied, natural gas liquids, liquefied refinery gas, other liquids, and all finished petroleum products except motor gasoline, jet fuel, distillate, and residual fuel oil.
[f] Includes stocks of all other oils, such as aviation gasoline, kerosene, natural gas liquids (including ethane), aviation gasoline blending components, naphtha and other oils for petrochemical feedstock use, special naphthas, lube oils, wax, coke, asphalt, road oil, and miscellaneous oils.

SPR: Strategic Petroleum Reserve. NGL: Natural Gas Liquids

Notes: Minor discrepancies with other EIA published historical data are due to rounding, with the following exception: recent petroleum demand and supply data displayed here reflect the incorporation of resubmissions of the data as reported in EIA's *Petroleum Supply Monthly*, TableC1. 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: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109, and *Weekly Petroleum Status Report*, DOE/EIA-0208.

Table A6. Annual U.S. Natural Gas Supply and Demand

(Trillion Cubic Feet)

	Year														
	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Supply															
Total Dry Gas Production	**17.10**	**17.31**	**17.81**	**17.70**	**17.84**	**18.10**	**18.82**	**18.60**	**18.85**	**18.90**	**18.71**	**18.62**	*18.83*	*19.84*	*20.34*
Net Imports	**1.22**	**1.27**	**1.45**	**1.64**	**1.92**	**2.21**	**2.46**	**2.69**	**2.78**	**2.84**	**2.99**	**3.42**	*3.49*	*4.03*	*4.19*
Supplemental Gaseous Fuels	**0.10**	**0.11**	**0.12**	**0.11**	**0.12**	**0.12**	**0.11**	**0.11**	**0.11**	**0.10**	**0.10**	**0.10**	*0.10*	*0.12*	*0.13*
Total New Supply	**18.42**	**18.69**	**19.38**	**19.45**	**19.88**	**20.42**	**21.39**	**21.40**	**21.75**	**21.84**	**21.80**	**22.14**	*22.42*	*24.00*	*24.65*
Working Gas in Storage															
Opening	**2.76**	**2.85**	**2.51**	**3.07**	**2.82**	**2.60**	**2.32**	**2.61**	**2.15**	**2.17**	**2.17**	**2.73**	*2.51*	*1.74*	*2.00*
Closing	**2.85**	**2.51**	**3.07**	**2.82**	**2.60**	**2.32**	**2.61**	**2.15**	**2.17**	**2.17**	**2.73**	**2.51**	*1.74*	*2.00*	*2.27*
Net Withdrawals	**-0.09**	**0.34**	**-0.56**	**0.24**	**0.23**	**0.28**	**-0.28**	**0.45**	**-0.02**	**0.00**	**-0.56**	**0.22**	*0.77*	*-0.26*	*-0.26*
Total Supply	**18.33**	**19.03**	**18.82**	**19.70**	**20.11**	**20.70**	**21.11**	**21.85**	**21.73**	**21.84**	**21.25**	**22.36**	*23.19*	*23.74*	*24.39*
Balancing Item [a]	**-0.30**	**-0.23**	**-0.11**	**-0.66**	**-0.56**	**-0.42**	**-0.40**	**-0.27**	**0.24**	**0.11**	**0.01**	**-0.67**	*-0.50*	*-0.39*	*-0.41*
Total Primary Supply	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.95**	**21.26**	**21.70**	*22.69*	*23.35*	*23.98*
Demand															
Lease and Plant Fuel	**1.10**	**1.07**	**1.24**	**1.13**	**1.17**	**1.17**	**1.12**	**1.22**	**1.25**	**1.20**	**1.16**	**1.08**	*1.24*	*1.27*	*1.28*
Pipeline Use	**0.61**	**0.63**	**0.66**	**0.60**	**0.59**	**0.62**	**0.69**	**0.70**	**0.71**	**0.75**	**0.64**	**0.74**	*0.68*	*0.70*	*0.71*
Residential	**4.63**	**4.78**	**4.39**	**4.56**	**4.69**	**4.96**	**4.85**	**4.85**	**5.24**	**4.98**	**4.52**	**4.73**	*4.97*	*5.17*	*5.16*
Commercial	**2.67**	**2.72**	**2.62**	**2.73**	**2.80**	**2.86**	**2.90**	**3.03**	**3.16**	**3.21**	**3.00**	**3.04**	*3.38*	*3.46*	*3.49*
Industrial (Incl. Nonutilities)	**6.38**	**6.82**	**7.02**	**7.23**	**7.53**	**7.98**	**8.17**	**8.58**	**8.87**	**8.83**	**8.69**	**9.00**	*9.38*	*9.76*	*10.31*
Electric Utilities	**2.64**	**2.79**	**2.79**	**2.79**	**2.77**	**2.68**	**2.99**	**3.20**	**2.73**	**2.97**	**3.26**	**3.11**	*3.04*	*2.99*	*3.03*
Total Demand	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.95**	**21.26**	**21.70**	*22.69*	*23.35*	*23.98*

[a] The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

Notes: Minor discrepancies with other EIA published historical data are due to 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: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Oil and Gas, Reserves and Natural Gas Division.

Table A7. Annual U.S. Coal Supply and Demand
(Million Short Tons)

	Year 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Supply															
Production	**950.3**	**980.7**	**1029.1**	**996.0**	**997.5**	**945.4**	**1033.5**	**1033.0**	**1063.9**	**1089.9**	**1117.5**	**1100.2**	*1106.9*	*1141.6*	*1159.2*
Appalachia	**NA**	**464.8**	**489.0**	**457.8**	**456.6**	**409.7**	**445.4**	**434.9**	**451.9**	**467.8**	**460.4**	**425.4**	*431.5*	*430.3*	*427.8*
Interior	**NA**	**198.1**	**205.8**	**195.4**	**195.7**	**167.2**	**179.9**	**168.5**	**172.8**	**170.9**	**168.4**	**162.5**	*152.4*	*149.7*	*145.1*
Western	**NA**	**317.9**	**334.3**	**342.8**	**345.3**	**368.5**	**408.3**	**429.6**	**439.1**	**451.3**	**488.8**	**512.3**	*522.9*	*561.6*	*586.4*
Primary Stock Levels [a]															
Opening	**28.3**	**30.4**	**29.0**	**33.4**	**33.0**	**34.0**	**25.3**	**33.2**	**34.4**	**28.6**	**34.0**	**36.5**	*39.5*	*34.2*	*34.9*
Closing	**30.4**	**29.0**	**33.4**	**33.0**	**34.0**	**25.3**	**33.2**	**34.4**	**28.6**	**34.0**	**36.5**	**39.5**	*34.2*	*34.9*	*35.2*
Net Withdrawals	**-2.1**	**1.4**	**-4.4**	**0.4**	**-1.0**	**8.7**	**-7.9**	**-1.2**	**5.8**	**-5.3**	**-2.6**	**-2.9**	*5.3*	*-0.7*	*-0.3*
Imports	**2.1**	**2.9**	**2.7**	**3.4**	**3.8**	**7.3**	**7.6**	**7.2**	**7.1**	**7.5**	**8.7**	**9.1**	*11.7*	*11.8*	*12.0*
Exports	**95.0**	**100.8**	**105.8**	**109.0**	**102.5**	**74.5**	**71.4**	**88.5**	**90.5**	**83.5**	**78.0**	**58.5**	*58.9*	*60.5*	*62.0*
Total Net Domestic Supply	**855.3**	**884.2**	**921.8**	**890.9**	**897.8**	**886.9**	**961.8**	**950.4**	**986.3**	**1008.5**	**1045.7**	**1047.9**	*1064.9*	*1092.3*	*1108.9*
Secondary Stock Levels [b]															
Opening	**185.5**	**158.4**	**146.1**	**168.2**	**167.7**	**163.7**	**120.5**	**136.1**	**134.6**	**123.0**	**106.4**	**129.4**	*143.5*	*124.6*	*124.6*
Closing	**158.4**	**146.1**	**168.2**	**167.7**	**163.7**	**120.5**	**136.1**	**134.6**	**123.0**	**106.4**	**129.4**	**143.5**	*124.6*	*124.6*	*113.0*
Net Withdrawals	**27.0**	**12.3**	**-22.1**	**0.5**	**4.0**	**43.2**	**-15.7**	**1.5**	**11.7**	**16.6**	**-23.0**	**-14.1**	*18.9*	*0.1*	*11.6*
Waste Coal Supplied to IPPs [c]	**0.0**	**0.0**	**0.0**	**0.0**	**6.0**	**6.4**	**7.9**	**8.5**	**8.8**	**8.1**	**8.6**	**12.0**	*12.2*	*12.2*	*12.2*
Total Supply	**882.3**	**896.5**	**899.4**	**891.4**	**907.8**	**936.5**	**954.0**	**960.4**	**1006.7**	**1033.2**	**1031.3**	**1045.8**	*1096.0*	*1104.6*	*1132.7*
Demand															
Coke Plants	**41.9**	**40.5**	**38.9**	**33.9**	**32.4**	**31.3**	**31.7**	**33.0**	**31.7**	**30.2**	**28.2**	**28.1**	*28.9*	*28.6*	*28.7*
Electricity Production															
Electric Utilities	**758.4**	**766.9**	**773.5**	**772.3**	**779.9**	**813.5**	**817.3**	**829.0**	**874.7**	**900.4**	**910.9**	**894.1**	*858.2*	*870.5*	*896.3*
Nonutilities (Excl. Cogen.) [d]	**NA**	**0.9**	**1.6**	**10.2**	**14.6**	**17.1**	**19.5**	**20.8**	**22.2**	**21.6**	**26.9**	**51.7**	*104.7*	*133.3*	*135.8*
Retail and General Industry	**76.3**	**82.3**	**83.1**	**81.6**	**80.2**	**81.1**	**81.2**	**78.9**	**76.9**	**77.1**	**73.0**	**70.3**	*71.5*	*72.2*	*71.9*
Total Demand [e]	**876.5**	**890.6**	**897.1**	**897.8**	**907.0**	**943.1**	**949.7**	**961.7**	**1005.6**	**1029.2**	**1039.0**	**1044.3**	*1063.4*	*1104.6*	*1132.7*
Discrepancy [f]	**5.8**	**5.9**	**2.4**	**-6.4**	**0.8**	**-6.6**	**4.3**	**-1.3**	**1.2**	**4.0**	**-7.7**	**1.6**	*32.6*	*0.0*	*0.0*

[a] Primary stocks are held at the mines, preparation plants, and distribution points.

[b] Secondary stocks are held by users. It includes an estimate of stocks held at utility plants sold to nonutility generators.

[c] Estimated independent power producers (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes.

[d] Estimates of coal consumption by IPPs, supplied by the Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration (EIA). Quarterly coal consumption estimates for 1999 and projections for 2000 and 2001 are based on (1) estimated consumption by utility power plants sold to nonutility generators during 1999, and (2) annual coal-fired generation at nonutilities from Form EIA-867 (Annual Nonutility Power Producer Report).

[e] Total Demand includes estimated IPP consumption.

[f] The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period. Prior to 1994, discrepancy may include some waste coal supplied to IPPs that has not been specifically identified.

Notes: Rows and columns may not add 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: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Quarterly Coal Report*, DOE/EIA-0121, and *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table A8. Annual U.S. Electricity Supply and Demand

(Billion Kilowatt-hours)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Supply															
Net Utility Generation															
Coal	**1540.7**	**1653.7**	**1559.6**	**1551.2**	**1575.9**	**1639.2**	**1635.5**	**1652.9**	**1737.5**	**1787.8**	**1807.5**	**1767.7**	*1699.8*	*1750.9*	*1771.0*
Petroleum	**148.9**	**158.3**	**117.0**	**111.5**	**88.9**	**99.5**	**91.0**	**60.8**	**67.3**	**77.8**	**110.2**	**86.9**	*65.1*	*81.9*	*94.3*
Natural Gas	**252.8**	**266.6**	**264.1**	**264.2**	**263.9**	**258.9**	**291.1**	**307.3**	**262.7**	**283.6**	**309.2**	**296.4**	*289.5*	*283.8*	*287.4*
Nuclear	**527.0**	**529.4**	**576.9**	**612.6**	**618.8**	**610.3**	**640.4**	**673.4**	**674.7**	**628.6**	**673.7**	**725.0**	*707.6*	*674.6*	*663.3*
Hydroelectric	**222.9**	**265.1**	**279.9**	**275.5**	**239.6**	**265.1**	**243.7**	**293.7**	**328.0**	**337.2**	**304.4**	**293.9**	*258.6*	*262.0*	*272.0*
Geothermal and Other [a]	**12.0**	**11.3**	**10.7**	**10.1**	**10.2**	**9.6**	**8.9**	**6.4**	**7.2**	**7.5**	**7.2**	**3.7**	*2.2*	*2.2*	*2.2*
Subtotal	**2704.3**	**2784.3**	**2808.2**	**2825.0**	**2797.2**	**2882.5**	**2910.7**	**2994.5**	**3077.4**	**3122.5**	**3212.2**	**3173.7**	*3022.8*	*3055.3*	*3090.2*
Nonutility Generation [b]	**0.0**	**187.6**	**187.6**	**216.7**	**246.3**	**314.4**	**343.1**	**363.3**	**369.6**	**371.7**	**405.7**	**554.7**	*781.2*	*847.1*	*886.7*
Total Generation	**2704.3**	**2971.9**	**3024.9**	**3071.3**	**3083.4**	**3196.9**	**3253.8**	**3357.8**	**3447.0**	**3494.2**	**3617.9**	**3728.4**	*3804.1*	*3902.4*	*3976.9*
Net Imports [c]	**31.8**	**11.0**	**2.3**	**19.6**	**25.4**	**27.8**	**44.8**	**39.2**	**38.0**	**36.6**	**27.6**	**30.6**	*39.3*	*37.2*	*35.9*
Total Supply	**2736.0**	**2982.8**	**3027.2**	**3091.0**	**3108.8**	**3224.7**	**3298.6**	**3397.1**	**3485.0**	**3530.8**	**3645.5**	**3759.0**	*3843.3*	*3939.6*	*4012.8*
Losses and Unaccounted for [d]	**NA**	**243.2**	**207.3**	**215.0**	**223.6**	**236.4**	**225.7**	**238.4**	**242.3**	**242.9**	**249.4**	**337.7**	*240.1*	*274.9*	*280.3*
Demand															
Electric Utility Sales															
Residential	**892.9**	**905.5**	**924.0**	**955.4**	**935.9**	**994.8**	**1008.5**	**1042.5**	**1082.5**	**1075.8**	**1127.7**	**1140.8**	*1183.9*	*1215.3*	*1237.6*
Commercial	**699.1**	**725.9**	**751.0**	**765.7**	**761.3**	**794.6**	**820.3**	**862.7**	**887.4**	**928.4**	**968.5**	**970.6**	*1028.2*	*1042.3*	*1059.7*
Industrial	**896.5**	**925.7**	**945.5**	**946.6**	**972.7**	**977.2**	**1008.0**	**1012.7**	**1030.4**	**1032.7**	**1040.0**	**1017.8**	*1074.0*	*1076.8*	*1100.3*
Other	**89.6**	**89.8**	**92.0**	**94.3**	**93.4**	**94.9**	**97.8**	**95.4**	**97.5**	**102.9**	**103.5**	**106.8**	*111.6*	*112.4*	*114.9*
Subtotal	**2578.1**	**2646.8**	**2712.6**	**2762.0**	**2763.4**	**2861.5**	**2934.6**	**3013.3**	**3097.8**	**3139.8**	**3239.8**	**3235.9**	*3397.7*	*3446.8*	*3512.4*
Nonutility Own Use [e]	**NA**	**92.9**	**94.7**	**101.5**	**108.0**	**126.9**	**138.4**	**145.4**	**144.9**	**148.2**	**156.2**	**185.3**	*205.5*	*217.8*	*220.2*
Total Demand	**NA**	**2739.7**	**2819.9**	**2875.9**	**2885.2**	**2988.4**	**3073.0**	**3158.7**	**3242.7**	**3287.9**	**3396.1**	**3421.2**	*3603.3*	*3664.7*	*3732.6*
Memo:															
Nonutility Sales to Electric Utilities	**NA**	**NA**	**92.9**	**115.2**	**138.3**	**187.5**	**204.7**	**217.9**	**224.7**	**223.5**	**249.5**	**369.4**	*575.7*	*629.2*	*666.5*

[a]Other includes generation from wind, wood, waste, and solar sources.
[b]Net generation.
[c]Data for 1999 are estimates.
[d]Balancing item, mainly transmission and distribution losses.
[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 1999 are estimates.

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics.
Sources: Historical data: Energy Information Administration; latest data available from EIA databases supporting the following report: *Electric Power Monthly*, DOE/EIA-0226 and Electric Power Annual,DOE/EIA-0348.
Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.