Originally Processed With FOIA(s): S; 2011-1613-F[1]

FOIA Number: S

FOIA MARKER

This is not a textual record. This is used as an administrative marker by the George Bush Presidential Library Staff.

Record Group/Collection: George H.W. Bush Presidential Records
Collection/Office of Origin: Speechwriting, White House Office of
Series: Speech File Backup Files
Subseries: Chron File, 1989-1993

OA/ID Number: 13778
Folder ID Number: 13778-004

Folder Title:
American Gas Assoc. Teleconference 10/28/91 [OA 8317] [1]

Stack:	Row:	Section:	Shelf:	Position:
G	26	21	7	3

THE WHITE HOUSE

WASHINGTON

AUGUST 5, 1991

MEMORANDUM FOR BARRY TRON, DIRECTOR, PUBLIC AFFAIRS

FROM: JEFF VOGT, ASSOCIATE DIRECTOR, PUBLIC LIAISON

SUBJECT: SATELLITE TELECONFERENCE FOR AMERICAN GAS ASSOCIATION (AGA) CONFERENCE

Attached is a letter from AGA requesting a satellite teleconference with the President for their annual conference in San Diego, CA; October 27 - 30, 1991.

I strongly recommend this request be granted. The event allows a forum for our National Energy Strategy. Moreover, AGA has been extremely helpful with a number of issues on the Hill, including the budget agreement, the Gulf vote, the capital gains fight and clean air legislation. The conference is expected to exceed 1,500 in attendance.

Please let me know if you need additional information. Thanks, Barry.

cc: Bobbie Kilberg
Kathy Jeavons

Russ Keene will call by COB Fri. 10/18 (w/ TPs, bckgrnd)

AGA American Gas Association

1515 Wilson Boulevard, Arlington, Va. 22209
Telephone (703) 841-8612

Michael Baly III
President

→ will intro POTUS

July 8, 1991

RESEARCH : RUSS KEENE
703-841 8595

Mr. Jeff Vogt
Associate Director
Office of Public Liaison
The White House
Washington, D.C. 20500

Dear Jeff:

Pursuant to our discussion recently at the Spanish Ambassador's residence and your discussions with Russ Keene of my staff, it is my pleasure to invite President Bush to appear via teleconference hookup at A.G.A.'s American Gas Conference, scheduled for October 27-30, 1991 at San Diego's Marriott Marina Hotel.

The American Gas Conference is the natural gas industry's largest general interest meeting. We expect more than 1,000 delegates and 500 spouses and guests to attend the meeting representing all levels of management from natural gas distribution and pipeline companies, gas producers, gas appliance manufacturers, government, financial organizations and other suppliers to our industry. The purpose of the conference is to discuss the major issues that will affect the gas industry over the next decade.

We believe our many industry executives -- including a sizeable California contingent -- would greatly enjoy the opportunity to see and hear the President. Issues of interest include the Administration's NES (which we strongly endorse), alternative fuel vehicle development, environmental challenges and, of course, any other issue on the President's mind that he would care to pass along to our group of industry leaders.

We look forward to working with you and others in the White House on a Presidential teleconference to the American Gas Conference in October.

Thank you for your consideration in this matter.

Sincerely,

Mike Baly

EDT 12:NOON Oct 28, 1990 MONDAY

Michael Baly III

Chair. PHIL McCORMICK
[illegible] Chair

TECH: ROB QUINN

THE WHITE HOUSE

WASHINGTON

August 8, 1991

SCHEDULE PROPOSAL

TO: KATHY SUPER
Deputy Assistant to the President for Appointments and Scheduling

THROUGH: DORRANCE SMITH
Assistant to the President for Media Affairs

FROM: BARRIE TRON
Director of Public Affairs

REQUEST: Satellite teleconference for the American Gas Association's American Gas Conference

PURPOSE: To articulate the President's National Energy Strategy, to an influential industry group.

BACKGROUND: The American Gas Association (AGA) is holding a major industry conference in San Diego in which over 1,500 people are expected to attend. This group has been very supportive of the President's National Energy Strategy as well as other key initiatives including; the budget agreement, the Gulf vote, the capital gains fight, and the clean air legislation.

PREVIOUS PARTICIPATION: None

DATE AND TIME: October 27 - 30, 1991

DURATION: 20 minutes

LOCATION: OEOB 459

PARTICIPANTS: Dorrance Smith
Barrie Tron
WHCA personnel (2)
White House photographer
Interface Video Productions (3)

OUTLINE OF EVENT: The President enters the Studio, participates in the satellite teleconference, then departs.

REMARKS REQUIRED: Brief remarks to be provided by the Office of Communications

MEDIA COVERAGE: Closed press

RECOMMENDED BY: Bobbie Kilberg
Jeff Vogt
Barrie Tron

FACT-CHECK COPY

Grant / Aarhus
A:AGA Draft two
October 22, 1991

BRIEF REMARKS: AMERICAN GAS ASSOCIATION TELECONFERENCE
MONDAY, OCTOBER 28, 1991
~~10 A.M.~~ NOON

Chairman Bill McCormick
Ch.-Elect Dick Farman

Thank you, Mike [Baly, President of AGA]. I'm glad to be able to join you by satellite in San Diego at the 73rd Annual Conference of the American Gas Association. I understand you'll be hearing shortly from Gregg Petersmeyer, one of my top assistants and an "energy" expert himself -- he's a specialist on channeling the tremendous energy of volunteers in our society.

Russ

I'd like to talk to you today about America's energy future -- the indispensible foundation for the goods we produce, the enterprises we launch and the lifestyles we enjoy. When this Administration developed our National Energy Strategy, three principles guided our policy-making: reducing our dependence on foreign oil; protecting our environment; and promoting economic growth. As a part of our comprehensive energy strategy, natural gas is key to all three.

First, decreasing our dependence on foreign energy is a top priority of this Administration. We're willing to practice what we preach: in April of this year, I took action to put the federal government in the lead on reducing our import dependence by issuing an Executive Order that called for sharp reductions in federal energy use. Under this new mandate, overall energy consumption will be reduced by 20 percent from 1985 levels within

PresDoc 4/17 p.456-457

PresDoc

a decade, and federal automotive fuel consumption will be pared by ~~20~~ 10 percent from current levels within four years.

Unlike other energy types, there are abundant supplies of natural gas within our borders -- in fact, the Department of Energy recently reported a ~~111~~ 113 percent replacement of reserves for 1990 in the lower 48 states. And to guarantee that domestic supplies of natural gas remain steady, we want to rely on the logic of the marketplace. For example, in 1989 we enacted a law phasing out the last federal wellhead price controls on natural gas -- so that the free market could do its work.

Second, we are committed to preserving and protecting the environment. Again, in 1990, we looked to the ingenuity of the free market as we worked to defend our precious environment through enactment of the Clean Air Act Amendments. The A.G.A. was one of the first major trade groups to endorse our Administration's proposal for clean air legislation. I thank you for that effort. As clean-burning natural gas is put to work in increasing amounts for generating electricity, for fueling vehicles, for natural gas cooling in the summer -- Americans know the environment stands to benefit.

And third, energy security and environmental protection must go hand in hand with economic growth. That growth directly depends upon opening new markets and new opportunities for American industry. A North American Free Trade Agreement will promote economic growth throughout this continent. Your industry knows what I'm talking about: already, the northern tier of

Mexico is the largest single export market for U.S. natural gas with some 200 million cubic feet flowing across the border each day. Next year, it is expected that the flow will increase to nearly 250 million cubic feet per day, and planned pipeline expansions could triple the export levels. AGA/DOE

Economic growth also depends upon an educated workforce. America's natural gas producers, companies and utilities are doing a great deal to make their communities places where learning can happen. Your "Education 2000" program -- a ten-year, industry-wide commitment to helping our nation reform its schools -- is a great example of the partnerships necessary to invent a new generation of American schools. I urge you and your members to continue to pursue excellence in education so that we can prepare American children to compete -- and win -- in the global marketplace.

AGA educ. 2000 brochure

Economic growth, environmental conservation, energy security, and a well-prepared workforce -- all are crucial to America's success in the next century. As part of the fabric of daily life in America -- your companies and employees can make a difference. In many ways, you already are -- and for that, I thank you.

I wish you a successful conference and best wishes in the coming year. And now I'll take a few questions.

# # #

Mike Baly: Mr. President, our chairman Bill McCormick has a question for you.

Bill McCormick: Mr. President, we praise you for your leadership in the Clean Air Act Amendments passed by the Congress last year and we were pleased to support the Administration's goals and the Act. We appreciate your Administration's work toward enactment of the National Energy Strategy that you proposed earlier this year. A.G.A. also has been supportive of this initiative since the outset. The Senate looks like it will begin debate soon on the NES. How do you foresee the debate shaping and your Administration's role as the debate unfolds?

ANSWER: Bill, as I said earlier, securing a clean and affordable energy future is a very important objective of this Administration. That is why I am supporting S. 1220, the bipartisan energy bill ~~now being considered by the~~ Senate. This bill incorporates many important principles of our National Energy Strategy.

During the Senate's deliberations on this bill, we will be working very closely with Senators Johnston and Wallop to ensure that our key provisions remain intact. For example, many components of the bill, such as further deregulation of natural gas, will increase domestic energy production and energy efficiency. We need your industry's help in getting a good bill on my desk -- we are expecting a few tough votes -- but I am confident that the American people will understand the importance of enacting a comprehensive, balanced energy bill.

Mike Baly: Mr. President, our Chairman-elect, Dick Farman, has a question.

Dick Farman: Mr. President, in your remarks you mentioned A.G.A.'s Education 2000 program and we are all looking forward to hearing later in today's meeting from Gregg Petersmeyer on your Administration's national service efforts. Would you care to comment on other domestic initiatives that your Administration is currently working on or has plans to introduce in the next year?

ANSWER: Dick, we've advanced a broad, aggressive domestic agenda over the last two years -- one which has included such legislative successes as the Clean Air Act Amendments, the Americans with Disabilities Act, our Child Care bill, and our HOPE bill that promotes tenant management of public housing.

Looking ahead, we've already mentioned our America 2000 education initiative and our National Energy Strategy, and Congress is right now considering provisions of the Administration's tough crime bill -- a bill that we sent to the Congress two years in a row before we saw any action on it. You may remember that I challenged the Congress to complete action on just two bills -- that crime bill and our transportation bill -- in 100 days. But here we are, eight months later, still waiting for both.

We've also proposed a civil rights bill that will toughen our civil rights laws without resorting to unfair quotas. Just last week I signed an Executive Order to enact reforms in our civil justice system, and we'll be sending legislation to the Congress on that very soon.

But most importantly, we've offered numerous economic reform proposals which, if enacted by the Congress, would have long ago promoted the economic growth that America needs. We've proposed a capital gains tax cut to create more jobs, more federal funds for research and development, enterprise zones to stimulate our hardest-hit urban areas, and incentives for increased savings and investment. Throughout the coming legislative year, we will fight tooth and nail for economic growth, opportunity and jobs. I realize that's only a thumbnail sketch of our agenda, but I hope I've answered your question. Once again, thanks for the opportunity to join you today. Over and out.

# # #

Teleconference for the American Gas Association's Conference

10-28-91

Contacts: Paul Luthringer x2483
Maggie Minouge x7150

Gas is part of comprehensive strat

Grant / Aarhus
A:AGA Draft one
October 21, 1991

BRIEF REMARKS: AMERICAN GAS ASSOCIATION TELECONFERENCE
MONDAY, OCTOBER 28, 1991
10 A.M.

Thank you, Mike [Baly, President of AGA]. I'm glad to be able to join you by satellite in San Diego at the 73rd Annual Conference of the American Gas Association. I understand you'll be hearing shortly from Gregg Petersmeyer, one of my top assistants and an "energy" expert himself -- he's a specialist on channeling the tremendous energy of volunteers in our society. [Yuk Yuk]

I'd like to talk to you today about America's energy future -- the indispensible foundation for the goods we produce, the enterprises we launch and the lifestyles we enjoy. When this Administration developed our National Energy Strategy, three principles guided our policy-making: ensuring America's energy security; protecting our environment; and promoting economic growth. Natural gas is vital to all three.

Good summary have we said it before

First, ~~lessening~~ decreasing our dependence on foreign [oil] energy sources? is a top priority of this Administration. We're willing to practice what we preach: in April of this year, I took action to put the federal government in the lead on reducing our import dependence by issuing an Executive Order that called for sharp reductions in federal energy use. Under this new mandate, overall energy consumption will be reduced by 20 percent from 1985 levels within a decade, and automotive fuel consumption will be pared by 20 percent from current levels within four years.

can we really hope to make progress here?

Unlike other energy types, there are abundant supplies of natural gas within our borders -- in fact, the Department of Energy recently reported a 111 percent replacement of reserves for 1990 in the lower 48 states. And to guarantee that supplies of natural gas remain steady, we want to rely on the logic of the marketplace. For example, in 1989 we enacted a law phasing out the last federal wellhead price controls on natural gas -- so that the free market could do its work.

Secondly, ~~our~~ commitment to preserving and protecting the environment ~~is unwavering.~~ Again, in 1990, we looked to the ingenuity of the free market as we worked to defend our precious environment through enactment of the Clean Air Act Amendments. The A.G.A. was one of the first major trade groups to endorse our Administration proposal for clean air legislation. I thank you for that effort. Americans know the environment stands to benefit as clean-burning natural gas is put to work in increasing amounts for generating electricity, for fueling vehicles, for natural gas cooling in the summer, and in many other applications.

And thirdly, energy security and environmental protection must go hand in hand with economic growth. That growth directly depends upon opening new markets and new opportunities for American industry. A North American Free Trade Agreement will promote economic growth throughout this continent. Your industry knows what I'm talking about: already, the northern tier of Mexico is the largest single export market for U.S. natural gas with some 200 million cubic feet flowing across the border each day. Next year, it is expected that the flow will increase to nearly 250 million cubic feet per day, and planned pipeline expansions could triple the export levels.

Economic growth also depends upon an educated workforce. America's natural gas producers, companies and utilities are doing a great deal to make their communities places where learning can happen. Your "Education 2000" program -- a ten-year, industry-wide commitment to helping our nation reform its schools -- is a great example of the partnerships necessary to invent a new generation of American schools. I urge you and your members to continue to pursue excellence in education so that we can prepare American children to compete -- and win -- in the global marketplace.

Economic growth, environmental conservation, energy security, and a well-prepared workforce -- all are crucial to America's success in the next century. Where that place is -- where we stand in the international arena -- is up to the American people. As part of the fabric of daily life in America -- your companies and employees can make a difference. In many ways, you already are -- and for that, I thank you.

I wish you a successful conference and best wishes in the coming year. And now I'll take a few questions.

# # #

[Two questions to come]

INTRODUCTION OF PRESIDENT GEORGE BUSH BY MIKE BALY

1991 AMERICAN GAS CONFERENCE

SAN DIEGO, CALIFORNIA

OCTOBER 28, 1991

GOOD MORNING, MR. PRESIDENT, I JOIN THE OVER 1,000 OF YOUR FELLOW AMERICANS AND SUPPORTERS WHO APPRECIATE YOUR SPEAKING TO US TODAY. THE AMERICAN GAS ASSOCIATION IS GRATEFUL FOR YOUR ADMINISTRATION'S INCREASING FOCUS ON NATURAL GAS'S CONTRIBUTION TO OUR GREAT NATION. AS YOU KNOW, WE HAVE BEEN AGGRESSIVELY WORKING TOWARD ENACTMENT OF YOUR NATIONAL ENERGY STRATEGY.

MEMBERS AND FRIENDS OF THE AMERICAN GAS ASSOCIATION, IT IS AN HONOR AND A PRIVILEGE FOR ME TO PRESENT TO YOU A GREAT FRIEND FOR MANY YEARS OF THE AMERICAN GAS ASSOCIATION, THE PRESIDENT OF THE UNITED STATES.

AGA CONTACT: Russ Keene
703-841-8595

SUGGESTED REMARKS FOR PRESIDENT GEORGE BUSH

1991 AMERICAN GAS CONFERENCE

SAN DIEGO, CALIFORNIA

OCTOBER 28, 1991, 12:00 P.M. E.S.T.

THANK YOU, MIKE. AND CONGRATULATIONS ON A SUCCESSFUL FIRST YEAR AS PRESIDENT OF THE AMERICAN GAS ASSOCIATION.

I WISH YOU ALL WELL ON THE 73RD ANNUAL CONFERENCE OF THE AMERICAN GAS ASSOCIATION.

AS A VETERAN OF THE NATURAL GAS AND OIL BUSINESS, I FEEL A SPECIAL KINSHIP WITH YOU GATHERED IN SAN DIEGO. I REGRET THAT I CANNOT BE WITH YOU IN PERSON, BUT I AM PLEASED THAT GREGG PETERSMEYER OF OUR STAFF IS WITH YOU TODAY.

AMERICA'S ENERGY INDUSTRY IS THE INDISPENSABLE FOUNDATION TO THE GOODS WE PRODUCE, THE ENTERPRISES WE LAUNCH AND THE LIFESTYLES WE ENJOY. THE NATURAL GAS INDUSTRY IS JUST ONE PART OF OUR NATION'S ENERGY SECTOR. BUT THESE DAYS IT'S A PARTICULARLY EXCITING PART. THAT IS BECAUSE ENERGY SECURITY, A CLEAN ENVIRONMENT AND A COMPETITIVE ECONOMY ARE ALL HIGH ON THE LIST OF PUBLIC CONCERNS, AND THE USE OF NATURAL GAS HELPS AMERICANS TO ACHIEVE ALL THREE OF THESE GOALS.

NATURAL GAS HELPS OUR ENERGY SECURITY BECAUSE THERE ARE ABUNDANT SUPPLIES OF IT WITHIN OUR BORDERS. OUR DEPARTMENT OF ENERGY REPORTED RECENTLY A 111% REPLACEMENT OF RESERVES FOR 1990 IN THE LOWER 48 STATES. THAT'S AN IMPRESSIVE FEAT FOR A FUEL THAT SOME PEOPLE ONCE COUNTED OUT AS A DISAPPEARING RESOURCE. CLEARLY, THE PROBLEM BACK THEN WAS NOT A SCARCITY OF NATURAL GAS, BUT A SHORTAGE OF COMMON SENSE IN THE HALLS OF GOVERNMENT. TODAY, JUST AS THERE IS A NEW UNDERSTANDING OF FREE MARKETS AROUND THE WORLD, THERE IS WIDE AGREEMENT ACROSS THE POLITICAL SPECTRUM THAT A FREE MARKET IS THE BEST WAY TO ENSURE STEADY SUPPLIES OF NATURAL GAS. AND I AM PROUD THAT UNDER MY ADMINISTRATION IN 1989 WE ENACTED A LAW PHASING OUT THE LAST FEDERAL WELLHEAD PRICE CONTROLS ON NATURAL GAS SO THAT THE MARKET CAN DO ITS WORK. MY ADMINISTRATION LOOKS FORWARD TO WORKING WITH YOU TO INCREASE THE DEMAND FOR NATURAL GAS, SO THAT WE CAN PROVIDE FOR NOT ONLY A STRONG DRILLING INFRASTRUCTURE IN OUR COUNTRY BUT A STRONG DISTRIBUTION AND TRANSMISSION SYSTEM ALSO.

NATURAL GAS IS ALSO IMPORTANT FOR OUR COUNTRY'S ENVIRONMENT. IN ENACTING THE CLEAN AIR ACT AMENDMENTS OF 1990, OUR GOVERNMENT ENSURED THAT AMERICANS WILL ENJOY CLEANER AIR, AND WE DID SO IN A WAY THAT EMPOWERS THE FORCES OF THE MARKETPLACE RATHER THAN ENCUMBERING THEM.

A.G.A. WAS ONE OF THE FIRST MAJOR TRADE GROUPS TO ENDORSE OUR ADMINISTRATION PROPOSAL FOR THAT LEGISLATION. I THANK YOU FOR THAT EFFORT, AND I KNOW THE NATION WILL BENEFIT AS CLEAN BURNING NATURAL GAS IS PUT TO WORK IN INCREASING AMOUNTS FOR GENERATING ELECTRICITY, FOR FUELING VEHICLES, FOR NATURAL GAS COOLING IN THE SUMMER AND IN MANY OTHER APPLICATIONS.

NATURAL GAS IS A VERY ECONOMICAL FUEL. UNLIKE OIL, THE VAST MAJORITY OF THE GAS WE USE IS PRODUCED HERE IN THIS COUNTRY, AND ALMOST ALL OF IT IN THIS CONTINENT. AND, AS MUCH AS I FAVOR DEVELOPING OUR DOMESTIC OIL INDUSTRY TO THE FULLEST, NATURAL GAS IS SIGNIFICANTLY CHEAPER THAN OIL ON AN ENERGY EQUIVALENT BASIS. THAT'S WHY WHEN MY ADMINISTRATION'S BALANCED NATIONAL ENERGY STRATEGY PROPOSAL WAS INTRODUCED IN FEBRUARY, WE SAID THAT MAKING A CHOICE TO INCREASE OUR USE OF NATURAL GAS COULD "BOOST THE GROSS NATIONAL PRODUCT, REDUCE OIL IMPORTS, AND IMPROVE THE NATION'S TRADE BALANCE."

AS YOU KNOW, MANY OF THE PROVISIONS FOR OUR NATIONAL ENERGY STRATEGY OUR NOW EMBODIED IN LEGISLATION BEING CONSIDERED BY THE CONGRESS AND I APPRECIATE VERY MUCH, MIKE, AND CHAIRMAN BILL MCCORMICK WHAT A.G.A. IS DOING IN ACTIVELY SUPPORTING THIS LEGISLATION.

TODAY, I CAN THINK OF NO MORE IMPORTANT CHOICE THAT AMERICANS CAN MAKE THAN TO GIVE THE NATIONAL ENERGY SECURITY ACT A VIGOROUS

BACKING. FOR THREE MORE DAYS IT WILL BE NATIONAL ENERGY AWARENESS MONTH. THERE IS NO BETTER TIME TO REMIND YOUR SENATORS AND CONGRESSMEN HOW VITAL IT IS THAT WE BEGIN TO PUT IN PLACE A NATIONAL ENERGY STRATEGY TO BEST UTILIZE ALL OF OUR NATION'S ENERGY RESOURCES.

ANOTHER PART OF THE STRATEGY IS TO ENSURE A FAIR AND EXPEDITIOUS REGULATORY SYSTEM FOR INTERSTATE PIPELINES. YOUR INDUSTRY HAS SEEN DRAMATIC CHANGE IN RECENT YEARS AS THE FEDERAL ENERGY REGULATORY COMMISSION HAS USHERED IN THE ERA OF "OPEN ACCESS" TRANSMISSION. I HOPE THAT YOU AGREE WITH ME THAT MARTIN ALLDAY IS DOING A FINE JOB AS FERC CHAIRMAN AND I APPRECIATE A.G.A.'S CLOSE WORKING RELATIONSHIP WITH HIM.

I KNOW YOU ARE WORKING WITH MARTIN ON SOME CHANGES TO THE RECENT RULEMAKING AT FERC AND WE HOPE THAT WE CAN BE RESPONSIVE TO YOUR CONCERNS ON THIS.

SPEAKING TO YOU IN SOUTHERN CALIFORNIA, I CAN'T FAIL TO MENTION AN EXCITING NEW TECHNOLOGY THAT PROMISES TO HELP OUR NATION RESPOND TO BOTH THE CLEAN AIR ACT AND THE NATIONAL ENERGY STRATEGY. I MEAN NATURAL GAS VEHICLES.

SOUTHERN CALIFORNIA HAS TAKEN A LEAD IN LOOKING AT ALTERNATIVES TO TRADITIONAL GASOLINE AND DIESEL FUELS. I KNOW YOUR INCOMING CHAIRMAN

DICK FARMAN AND HIS COMPANY, SOUTHERN CALIFORNIA GAS CO., HAVE BEEN ACTIVE IN THE NATURAL GAS VEHICLE FIELD. SO HAVE MANY OTHERS AROUND THE COUNTRY. THE FEDERAL GOVERNMENT OPERATES OVER 200,000 CIVILIAN STYLE VEHICLES AND PURCHASES AROUND 50,000 EACH YEAR. EQUIPPING AS MANY AS POSSIBLE TO BURN ALTERNATIVE FUELS CAN HELP TO ESTABLISH A MARKET FOR SUCH VEHICLES, AND DEMONSTRATE THEIR FEASIBILITY TO THE PRIVATE SECTOR. OUR ADMINISTRATION IS WORKING TO CONVERT OUR OWN GOVERNMENT VEHICLES, AS YOU'VE SEEN IN THE DEPARTMENT OF ENERGY AND NOW THE DEPARTMENT OF NAVY, THE POSTAL SERVICE -- AND THERE WILL BE OTHERS AS WELL.

TODAY, FEDERAL AGENCIES USE OVER 480,000 BARRELS OF PETROLEUM PRODUCTS EACH DAY. THAT NUMBER INCLUDES OVER 5.8 MILLION GALLONS OF FUEL OIL, AND 3.6 MILLION GALLONS OF GASOLINE. WE CAN DO BETTER. WE MUST DO BETTER. WE WILL DO BETTER. INDEED, THE FEDERAL GOVERNMENT NEEDS TO LEAD THE WAY IN SHOWING HOW WE CAN CUT OUR OIL IMPORT DEPENDENCE, AND ASSURE AMERICA'S ENERGY SECURITY.

ON APRIL 17TH, 1991, I TOOK ACTION TO PUT THE FEDERAL GOVERNMENT IN THE LEAD ON REDUCING OUR IMPORT DEPENDENCE BY ISSUING AN EXECUTIVE ORDER THAT CALLED FOR SHARP REDUCTIONS IN FEDERAL ENERGY USE. UNDER THIS NEW MANDATE, OVERALL ENERGY CONSUMPTION WILL BE REDUCED BY 20 PERCENT FROM 1985 LEVELS WITHIN A DECADE, AND AUTOMOTIVE FUEL CONSUMPTION WILL BE PARED BY 10 PERCENT FROM CURRENT LEVELS WITHIN

FOUR YEARS.

I KNOW THAT YOUR BOARD OF DIRECTORS YESTERDAY DISCUSSED INCREASING SHORT-TERM DEMAND FOR NATURAL GAS WHICH INCLUDED URGING OUR GOVERNMENT TO LOOK AT REDUCING OIL IN 80,000 OF OUR GOVERNMENT'S FEDERAL INSTALLATIONS. PLEASE BE ASSURED THAT WE ARE TAKING YOUR ADVICE AND COUNSEL UNDER CONSIDERATION AND WILL BE IN TOUCH WITH YOU ON THIS SOON.

OUR WORK ON A NORTH AMERICAN FREE TRADE AGREEMENT HOLDS FORTH THE PROMISE OF UNFETTERING COMMERCE IN ENERGY THROUGHOUT THE CONTINENT. WE HAVE ALREADY SEEN HOW IMPORTANT THIS TRADE CAN BE. TODAY, THE NORTHERN TIER OF MEXICO IS THE LARGEST SINGLE EXPORT MARKET FOR U.S. NATURAL GAS WITH SOME 200 MILLION CUBIC FEET FLOWING ACROSS THE BORDER EACH DAY. NEXT YEAR IT IS EXPECTED THAT THE FLOW WILL INCREASE TO FROM 225 TO 250 MILLION CUBIC FEET PER DAY, AND PLANNED PIPELINE EXPANSIONS COULD RAISE THAT FIGURE TO 750 MILLION CUBIC FEET PER DAY. I APPRECIATE THE SUPPORTIVE LETTER A.G.A. SENT TO AMBASSADOR HILLS, OUR U.S. TRADE REPRESENTATIVE, WHICH POINTED OUT THE NEED TO COVER ENERGY IN THE NEGOTIATIONS TO ELIMINATE BARRIERS FOR TRADE IN NORTH AMERICA.

FINALLY, I COMMEND YOU ON YOUR "EDUCATION 2000" PROGRAM -- A 10-YEAR, INDUSTRY WIDE COMMITMENT TO HELPING OUR NATION REFORM ITS SCHOOLS

TO MEET THE 6 NATIONAL GOALS AGREED UPON BY ME AND THE NATION'S GOVERNORS AT THE ENERGY SUMMIT SEVERAL YEARS AGO.

AMERICA'S NATURAL GAS COMPANIES, NATURAL GAS UTILITIES AND PIPELINES AND PRODUCERS ALREADY DO A GREAT DEAL IN THEIR COMMUNITIES AND SERVICE AREAS TO ADVANCE THE CAUSE OF U.S. EDUCATION. UNDER THE BANNER OF "EDUCATION 2000," WITH A.G.A. ACTING AS A CLEARINGHOUSE FOR IDEAS, YOU WILL BE DOING MORE IN THE YEARS TO COME. AND I WELCOME THAT, BECAUSE IT IS IMPERATIVE THAT, THROUGH OUR ADMINISTRATION'S AMERICA 2000 PROGRAM, ALONG WITH YOUR PROGRAM AND OTHERS, THAT WE REFORM THE EDUCATIONAL SYSTEM SO THAT IT CAN PREPARE AMERICAN CHILDREN TO COMPETE EFFECTIVELY IN THE WORLD ECONOMY.

I AM PLEASED THAT GREGG PETERSMEYER, ~~ONE OF MY SENIOR~~ ASSISTANTS AND DIRECTOR OF NATIONAL SERVICE, WILL BE SPEAKING TO YOU TODAY. HIS OFFICE OVERSEES OUR "POINTS OF LIGHT" PROGRAM WHICH SEEKS TO CHANNEL THE ENORMOUS ENERGIES OF VOLUNTEERISM IN OUR SOCIETY. WHEN WE VISUALIZE A THOUSAND POINTS OF LIGHT, SOME OF THESE LIGHTS ARE GAS LIGHTS.

THAT'S WHY I PARTICULARLY COMMEND YOUR INCOMING CHAIRMAN DICK FARMAN ON HIS NEW THEME, OF "AMERICA'S NATURAL GAS INDUSTRY: WORKING TOGETHER TO MARKET THE FUEL OF CHOICE" BECAUSE INDUSTRY UNITY WILL BE VERY IMPORTANT TO MARKET THE BENEFITS OF NATURAL GAS IN OUR COUNTRY. I BELIEVE THAT THE ROLE OF THE AMERICAN GAS ASSOCIATION IS

CRITICAL IN HELPING BRING ALL THE SEGMENTS OF OUR INDUSTRY TOGETHER -- THE PRODUCERS, PIPELINES AND UTILITIES -- TO WORK TOWARD THE NATIONAL GOALS WHICH I HAVE CITED.

IN CLOSING, LET ME ASSURE YOU THAT MY ADMINISTRATION SEES NATURAL GAS AS A VERSATILE ENERGY RESOURCE OF GROWING IMPORTANCE FOR AMERICA INTO THE 21ST CENTURY. WHEN CHOICES ARE MADE ABOUT ENERGY, NATURAL GAS IS A VERY WISE CHOICE.

I WISH YOU A SUCCESSFUL CONFERENCE, THANK YOU FOR INVITING ME TO PARTICIPATE. NOW I'LL BE HAPPY TO TAKE A COUPLE OF QUESTIONS.

# # # # #

Proposed Q&A

MIKE BALY:

MR. PRESIDENT, OUR CHAIRMAN BILL MCCORMICK HAS A QUESTION FOR YOU.

BILL MCCORMICK:

MR. PRESIDENT, AT SOME TIME IN THE NEAR FUTURE WE'D LIKE TO INTRODUCE TO YOU THE QUALITY BENEFITS OF THE FIRST MASS-PRODUCED ALL NATURAL GAS PICK-UP TRUCK MANUFACTURED BY GMC TRUCK. OUR INDUSTRY HOPES TO SELL 5-8,000 OF THESE VEHICLES TO DEMONSTRATE THEIR ABILITY TO CONTRIBUTE TO IMPROVING AIR QUALITY AS YOU TOUCHED UPON IN YOUR

REMARKS. MAY I CORDIALLY INVITE YOU TO TAKE A SPIN IN AN NGV, MR. PRESIDENT. IT COULD BE ARRANGED ALMOST ANY TIME SINCE ONE OF THE NATION'S MORE THAN 350 NATURAL GAS VEHICLE FUELING STATIONS IS NOW OPEN JUST DOWN THE STREET FROM THE WHITE HOUSE.

BUSH ANSWER:

BILL, I HAVE BEEN IN A DUAL-FUEL NATURAL GAS VEHICLE AND I REMEMBER IT LOOKED JUST LIKE A REGULAR CAR, RODE JUST LIKE A REGULAR CAR, BUT THE ONLY DIFFERNCE WAS IT DID NOT POLLUTE LIKE A REGULAR CAR! AND, BILL, I WOULD LIKE TO COMPLIMENT YOU ON YOUR LEADERSHIP IN REPRESENTING THE GAS INDUSTRY IN MANY MEETINGS WITH THE BIG THREE AUTO MAKERS WHICH BROUGHT ABOUT THE DEVELOPMENT OF THESE PROMOSING NEW VEHICLES. AS VICE PRESIDENT, I SERVED AS CHAIRMAN OF THE WHITE HOUSE COMMISSION ON REGULATORY REFORM. IN THAT CAPACITY I BECAME FAMILIAR WITH THE ADVANTAGES OF ALTERNATIVE FUELS AND THE IMPORTANT ROLE THAT COMPRESSED NATURAL GAS CAN PLAY. AT THAT TIME I CALLED NATURAL GAS OUR NATION'S "ACE IN THE HOLE." -- AND I BELIEVE THAT EVEN MORE STRONGLY TODAY. I LOOK FORWARD TO RIDING IN THAT NEW ALL NATURAL GAS PICK-UP TRUCK SOON, JUST LIKE WE USE DOWN IN TEXAS.

MIKE BALY:

MR. PRESIDENT, OUR CHAIRMAN-ELECT, DICK FARMAN, HAS A QUESTION FOR YOU.

DICK FARMAN:

MR. PRESIDENT, TODAY ABOUT 7 PERCENT OF FEDERAL ENERGY RESEARCH-AND-DEVELOPMENT DOLLARS ARE TARGETED TO NATURAL GAS PRODUCTION AND USE TECHNOLOGIES, THOUGH NATURAL GAS ACCOUNTS FOR 24 PERCENT OF THE NATION'S ENERGY USE. I VERY MUCH APPRECIATE HENSON MOORE'S WILLINGNESS TO DISCUSS THIS IMPORTANT MATTER WITH ME ON SEVERAL OCCAISIONS. DO YOU FORESEE THAT NATURAL GAS WILL RECEIVE INCREASED FEDERAL R&D FUNDING?

BUSH ANSWER:

DICK, OUR NES PRINCIPLES INCLUDE EMPHASIS ON R&D INITIATIVES AS WELL AS ENHANCING OUR NATION'S ENVIRONMENTAL QUALITY AND REDUCING OUR DEPENDENCE ON IMPORTED OIL. NATURAL GAS FITS VERY WELL WITHIN THESE PRINCIPLES. SO, I FULLY EXPECT THAT YOU WILL SEE MY BUDGET RECOMMENDATIONS FOR INCREASES IN NATURAL GAS R&D.

THE WHITE HOUSE
WASHINGTON

AGA — DOE reported 111% replacement of reserves for 1990 figure

– how does it get replaced?

703-841-8400

Russ Keene

EIA # Energy Info Admin. DOE agency study from 2 mos. ago

average of 30 top producing companies (Exxon, Mobil, etc.) → bulk of suppliers

how much gas did you sell? how much gas did you find to replace what you sold. → in the ground.

discovered new supplies

AGA American Gas Association

1515 Wilson Boulevard, Arlington, Va. 22209
Telephone (703) 841-8612

Michael Baly III
President

October 17, 1991

Hon. Carla A. Hills
United States Trade Representative
600 17th Street, N.W.
Washington, DC 20506

Dear Ambassador Hills:

The natural gas industry would like to take this opportunity to commend you and your staff on the progress made toward developing a North American Free Trade Agreement. Our industry supports the Administration in its effort of eliminating barriers for trade, and would like to ensure that energy, including natural gas, issues continue to be covered in your negotiation.

At the present time, the U.S. natural gas industry is poised to export increasing volumes of natural gas to Mexico. However, in order to maximize cross-border energy trade, we need to develop the transmission and distribution systems needed in Mexico to deliver the gas, as well as end-uses for that gas, such as gas-fired electric power generation. The ability to develop the energy infrastructure in Mexico is an important trade opportunity for U.S. energy companies. Our companies have expertise both in the design and construction of natural gas delivery systems and gas-fired electric generating stations.

If we can be of assistance to your office on these issues please do not hesitate to call upon us. Lorraine Cross, our director of State and Executive Branch Relations and Tom Saunders, our manager of Federal Financial Relations from Energen Corp. of Birmingham, Alabama are at your service.

Sincerely,

Michael Baly III

Michael Baly III

American Gas Association

Planning & Analysis Issues

Issue Brief 1991 - 8

July 3, 1991

1991 MID-YEAR GAS DEMAND OUTLOOK

Natural gas consumption was up slightly in the first quarter of 1991. After levelling off in 1990 due to warm weather, preliminary first quarter gas consumption data show an overall 7% increase compared to the first quarter of 1990. While the winter of 1990-1991 was again warmer-than-normal, the heating degree day accumulation for January through March was 11% greater than in the first quarter of 1990. Moreover, the fact that September through December of 1990 was 7.9% warmer-than-normal suggests that the temperature-sensitive segments of the residential and commercial markets are likely to show growth in the fourth quarter of 1991.

The year-to-date growth in the industrial and electricity generation sectors, which was stronger than the residential and commercial sectors, was also positively influenced by year-to-year weather changes. The principal other factor influencing these large volume markets was the low spot gas prices, which resulted in dual-fuel capable customers choosing gas over oil. Industrial and electric generation use of natural gas increased 11% in January/February of 1991 compared to the same period in 1990, while oil use declined 2.3% in these sectors.

While industrial gas demand is expected to continue to outpace 1990 for the remainder of 1991 due to favorable natural gas/oil price spreads, higher hydroelectric production will dampen gas demand in the electric utility sector. Given the extremely low spot prices, natural gas will effectively compete against coal (directly and coal-over-wire). Overall, the A.G.A. projection is for flat demand in the low case relative to 1990 and the potential for gas demand to reach 20.2 quads this year at the high end, with a base case forecast of 19.8 quads. Should the high case be reached it would be the first time since 1980 that natural gas demand was at the 20 quad level.

TABLE 1
1991 MID - YEAR OUTLOOK
(Quadrillion Btu)

	1990[1]	1991 A.G.A. Forecast		
		Low	Base	High
Residential	4.6	4.7	4.8	4.9
Commercial	2.7	2.7	2.8	2.8
Industrial	7.3	7.4	7.5	7.6
Electric Generation	2.9	2.8	2.9	3.0
Subtotal	17.5	17.6	18.0	18.3
Lease & Plant	1.3	1.2	1.2	1.3
Pipeline	0.6	0.6	0.6	0.6
TOTAL	19.4	19.4	19.8	20.2
Percent Gain		-	2.1%	4.1%

[1] Energy Information Administration, Monthly Energy Review, May 28, 1991.

1515 Wilson Boulevard • Arlington, VA 22209

Summary

Residential and Commercial

The modest rise in residential and commercial gas demand was overwhelmingly related to weather. Looking to the latter part of the year, the prospect is good for a weather-related increase over the prior year since September through December of 1990 was 7.9% warmer than normal. Natural gas' favorable (59%) market share position in new single family housing completions (compared with 33% for electricity and 5% for oil) and continued strength in conversions to natural gas are other positive factors in these sectors.

Industrial

The traditional economic indicators, which have turned negative, can not explain the steady growth in industrial gas consumption. Fuel switching from oil and cogeneration demand (resulting from record cogeneration filings in the mid-1980's) appear to be more important factors. The recessionary economy at large, as reflected in a decline in real GNP of 2.8% in the first quarter of 1991 compared to the fourth quarter of 1990, has been outweighed by the impact of other gas-related factors. A key factor is the historically low prices for natural gas on the spot market, which has induced large volume users to take advantage of depressed gas prices relative to coal and oil prices. Energy Information Administration data for January-April show that both distillate and residual oil supplied to the market were down 5% and 14%, respectively.

Electric Generation

Natural gas is benefitting competitively from a range of factors influencing fuel use for electricity generation. The low spot price for gas is a primary reason why gas consumption for electricity generation has increased in the first quarter, while oil consumption has declined. First quarter data show that while natural gas consumption was up 10.3% (.049 quads), fuel oil consumption for electricity generation was down 15.4%. Electricity consumption was up slightly (1.4%) in January and February and is expected to continue to grow at this reduced rate during 1991.

TABLE 2
First Quarter Comparison
(Quadrillion Btu)

	1990[1] 1st Q	1991 1st Q	Δ%
Residential	2.032	2.153	6.0%
Commercial	1.078	1.130	4.8%
Industrial	1.799	2.001	11.2%
Electric Generation	.475	.524	10.3%
Subtotal	5.384	5.808	7.9%
Lease & Plant	.325	.323	-0.3%
Pipeline	.154	.161	4.6%
Total	5.863	6.292	7.3%

[1] Energy Information Administration, Monthly Energy Review, May 28, 1991.

American Gas Association

Planning & Analysis Issues

Issue Brief 1991-3

January 16, 1991

The Role of Natural Gas in Offsetting Oil: 1991 Update

A. Introduction

The invasion of Kuwait in August has brought the subject of U.S. dependence on oil imports to the forefront again. America now imports about half of the oil that it consumes. Most oil is used in the transportation sector, however, a large volume of fuel oil is also used in stationary applications: for space heating; for industrial process and boiler use; and for electricity generation. Oil use in stationary applications (excluding feedstocks) in 1989 amounted to 4.9 million barrels per day (b/d), or the equivalent of 68% of annual crude oil imports. Distillate and residual fuel oil, the oil products most likely to be offset by gas, make up half of that total. In contrast, natural gas is essentially a domestic resource with over 40 years of conventional supply under current consumption rates and the potential to extend the resource base well beyond the next century.

The purpose of this analysis is to demonstrate the extent to which natural gas can directly contribute to national energy security by substituting for oil in existing applications. This study updates a similar analysis published by A.G.A. in 1988. This analysis was prepared on a market-by-market basis over different time horizons: 30-day (immediate); 1 year; 5 years; and a 10-year potential. This analysis estimates oil displacement potential - it is not a forecast. Such levels would only be achievable if government policy actively promotes natural gas.

B. Executive Summary

In an emergency or oil supply disruption scenario natural gas could immediately offset 130 thousand barrels per day (mbd) of distillate and residual fuel oil in stationary applications. Within a year the rate of displacement could increase to 420 mbd as significant penetration in the dual-fuel capable boiler markets accumulates. After five years, the combination of growing conversions in the residential and commercial buildings sector (mainly on the East Coast) and further penetration in boiler and process markets would raise the penetration rate to 1.0 million b/d. If a comprehensive government initiative was begun now with a 10-year horizon, it is estimated that 1.5 million b/d of fuel oil use could be offset by the end of the decade. Adding 240 mbd that would, in effect, be offsets of gasoline use in fleet vehicles in the transportation sector, would bring total oil displacement by natural gas to 1.7 million b/d after 10 years.

1515 Wilson Boulevard • Arlington, VA 22209

An important component of this initiative would be increased natural gas pipeline capacity into oil-dependent regions. The volume of current planned natural gas pipeline capacity would go substantially toward accomodating the projected level of oil displacements over five years. To achieve the ten year goal, a similar increment in pipeline capacity and an increase in gas storage capacity would be needed. The exact size of the increment is dependent upon seasonal load factors and upon the volume of additional gas load that would derive from economic growth and other new sources.

The highlights for each stationary market and for the transportation sector for each succeeding timeframe are as follows and summarized in Table 1:

- The residential market for fuel oil is essentially distillate oil use concentrated on the U.S. East Coast, particularly in the Middle Atlantic census division which accounts for 5.6 million of the 11 million oil-heated households. Conversions from oil to natural gas heat already comprise the single largest source of residential conversions annually. Based on previous conversion growth rates it is possible to envision 350,000 conversions in the first year, displacing 20 mbd, rising to 500,000 conversions annually by the fifth year, resulting in oil offsets of 100 mbd after five years. If the annual rate of conversions then holds at 500,000, the cumulative potential impact after 10 years would be the displacement of 225 mbd of distillate fuel oil use -- roughly half of the current consumption level. This ten year goal would require additional pipeline and storage capacity and distribution mains given the seasonality and location of this load.

- In the commercial market, both distillate and residual fuel oil are used - primarily for spaceheating, but also for water heating in large multi-family buildings. Similar to the residential sector, commercial fuel oil consumption is also concentrated on the East Coast, but to a lesser extent. In the event of an oil supply disruption, displacement of oil use in dual-fuel boilers could reach 25 mbd. After a year, the displacement of all oil in gas-served buildings, as well as in a portion of the more than three million multi-family units with gas service nearby, would increase the offsets to 100 mbd. With increased penetration in the multi-family sector, the offsets could reach 190 mbd after five years and as much as 250 mbd after 10 years, or nearly 65 percent of the current level of commercial fuel oil use.

- The industrial market is the largest stationary market for fuel oil. Even after discounting those oil applications for which natural gas is not suited for displacement (such as feedstocks, asphalt and vessel bunkering) there remains nearly 900 mbd of distillate and residual fuel oil use in boiler and process applications that theoretically could be displaced by natural gas. Oil offsets could rise from 50 mbd in the immediate term to 200 mbd after a year. This would occur predominantly in dual-fuel boiler applications where gas and residual oil, in particular, are intensely competitive. After five years, when gas penetrates more into the applications using distillate oil, the offsets are projected to increase to 400 mbd. If there is, in fact, a policy designed to minimize the use of oil in industrial applications, the extension of gas service to a high proportion of what had formerly been unserved customers could potentially see the level of offsets reach 600 mbd after 10 years. While certainly a large volume, this would only be about 15 percent of all the oil consumption (including LPG) in the entire industrial market and two-thirds of the residual/distillate oil use. Like the residential and commercial sectors, displacement of oil in the industrial market to meet the ten year goal will require significant new construction of pipeline and distribution infrastructure. Seasonal service arrangments would also have to be enhanced.

- Fuel oil consumption (almost entirely residual oil)in the electric utility market is heavily concentrated on the East Coast. Over 80 percent of this oil consumption occurs in the three census divisions along the Atlantic. Unlike the industrial market, which is made up of thousands of customers and more widely distributed, the number of power plants involved is relatively small. About 125 of the 290 or so power plants that use fuel oil are on the East Coast -- and some of these plants are already dual - fuel capable. Consequently, the potential for oil offsets rises quickly from 50 mbd in the very short - term to 300 mbd after five years. With a concentrated national effort, three - quarters of fuel oil consumption could be offset in 10 years, reaching 400 mbd. Given the location of these plants, it is likely many plants would choose to be dual-fuel capable, interruptible gas customers. Thus complete displacement of oil year-round would be unlikely.

- In the transportation sector the displacements would be limited in the early years, reflecting the fact that a natural gas vehicle (NGV) manufacturing and fuel distribution infrastructure is now beginning to develop. The oil displacement rate would move up from minimal levels in the first five years, rising quickly by the end of the decade to 240 mbd as 2 million centrally-refueled fleet vehicles in major urban areas convert to natural gas. The passage of the Clean Air Act of 1990 alone will spur oil offsets in the transportation sector.

Table 1

Potential Oil Substitution
(thousand barrels/day)

Stationary Sources	**Immediate**	**One-Year**	**Five-Years**	**Ten-Years**
Residential	5	20	100	225
Commercial	25	100	190	250
Industrial	50	200	400	600
Electric Generation	50	100	300	400
Subtotal	**130**	**420**	**990**	**1475**
<u>**Mobile Sources**</u>				
Vehicles	-	-	5	240
Total	**130**	**420**	**995**	**1715**

Note: NGV market penetration grows dramatically after five years as a result of the new Clean Air Act legislation which begins to take effect in 1995. A.G.A. forecasts that by the year 2005 natural gas vehicles could displace as much as 675 mbd.

AGA American Gas Association

Energy Analysis

1515 Wilson Boulevard
Arlington, Virginia 22209

A.G.A. Planning & Analysis Group

EA 1991-5

April 16, 1991

Natural Gas and Electric Vehicles -- An Economic and Environmental Comparison with Gasoline Vehicles

A. Introduction

Alternative fuel vehicles -- i.e., vehicles operating on something other than conventional gasoline -- have faced a variety of hurdles in the marketplace. Despite numerous potential benefits, including environmental, energy security, and, in some cases, economic advantages, penetration by alternative fuel vehicles has been extremely limited to date. The existence of an extensive infrastructure for conventional gasoline vehicles, from vehicle production and maintenance to fuel distribution, has, in the past, proved to be a nearly insurmountable obstacle.

The outlook for alternative fuel vehicles has changed dramatically over the past year. Heightened environmental concerns culminated in the passage of the federal Clean Air Act Amendments of 1990 as well as in related state legislation. Primarily as a result of environmental legislation, and, to a lesser extent due to increasing concerns regarding world oil supply security and price, as many as 10 million alternative fuel vehicles are projected to be on the road by 2005.[1] These vehicles will be powered by natural gas, propane, electricity, methanol, ethanol and whatever other energy forms can meet the pollution reduction mandates of the law and the economic dictates of the marketplace.

The purpose of this analysis is to compare the projected mid-1990s economics and environmental impacts of two of the cleanest alternative fuel competitors -- natural gas and electricity -- with a conventional gasoline vehicle meeting the tougher emission standards that will be in place at that time. This analysis considers not only the vehicle per se, but also the ancillary environmental impacts attributable to fuel production, processing, transportation, conversion and distribution -- i.e., the "full cycle" impacts. In terms of economics, the analysis includes both the cost of vehicle purchase as well as operating costs.

B. Executive Summary

Economics. The mid-1990s cost of purchasing and operating natural gas vehicles (NGVs) is projected to be 4 percent less than the costs associated with conventional gasoline vehicles, and 23 to 35 percent less (range depends on battery life) than the costs of electric vehicles. See Exhibit 1.

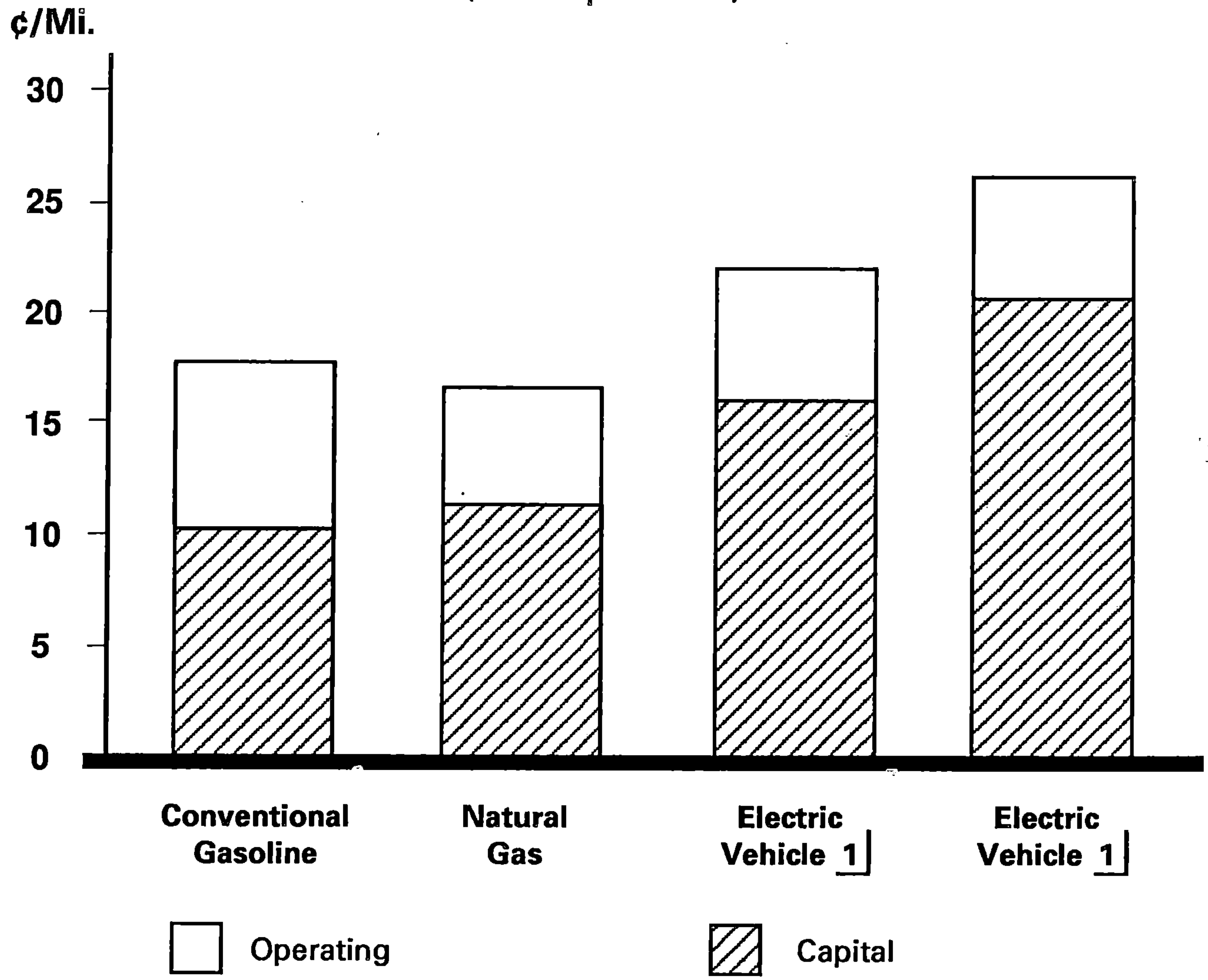
- The capital cost of the baseline gasoline vehicle (light-duty minivan, 1991 dollars) is $14,000, 7 percent less than the projected cost of a comparable factory built NGV ($15,000), and 36 percent less than the original cost of an electric van ($21,850). The costs of the NGVs and electric vehicles assume mass production by the mid-to-late 1990s.
  - Based on a 7-year operating life for the fleet van at 18,500 miles per year, the capital cost of the gasoline van is 10.5¢ per mile versus 11.3¢ per mile projected for the NGV.
  - The cost of the electric van is projected to be significantly higher, ranging from 16.4¢ to 20.4¢ per mile over its useful life of approximately 130,000 miles.
- The present value of the operating cost (fuel, fuel taxes, maintenance and repairs) of the NGV is projected to be 20 percent less than the operating cost of the gasoline vehicle -- 5.7¢ per mile versus 7.2¢ per mile. This 1.5¢ per mile operating cost advantage more than offsets the purchase price disadvantage of the NGV.
- The electric vehicle -- under relatively optimistic assumptions with respect to vehicle efficiency and electricity pricing -- is also projected to enjoy about a 20 percent operating cost advantage relative to the baseline gasoline vehicle. This advantage, however, cannot offset the capital cost penalty of the electric vehicle which is 56 to 94 percent greater than that of the baseline gasoline vehicle.

Environmental. NGVs offer significant potential emission reductions relative to gasoline in each of the five air pollutants analyzed, ranging from a 14 percent reduction in nitrogen oxides to a 90 percent reduction in carbon monoxide. (See Exhibit 2.) When the full cycle emissions associated with electricity generation are included, NGVs were also found to be superior to electric vehicles in terms of sulfur dioxide, nitrogen oxides and carbon dioxide emissions, while electric vehicles were cleaner for two categories -- nonmethane hydrocarbons and carbon monoxide. The incremental reduction from electric vehicles relative to NGVs for these two pollutants is, however, minor.

Exhibit 1

Economic Comparison of Conventional Gasoline, Electric and Natural Gas Vehicles

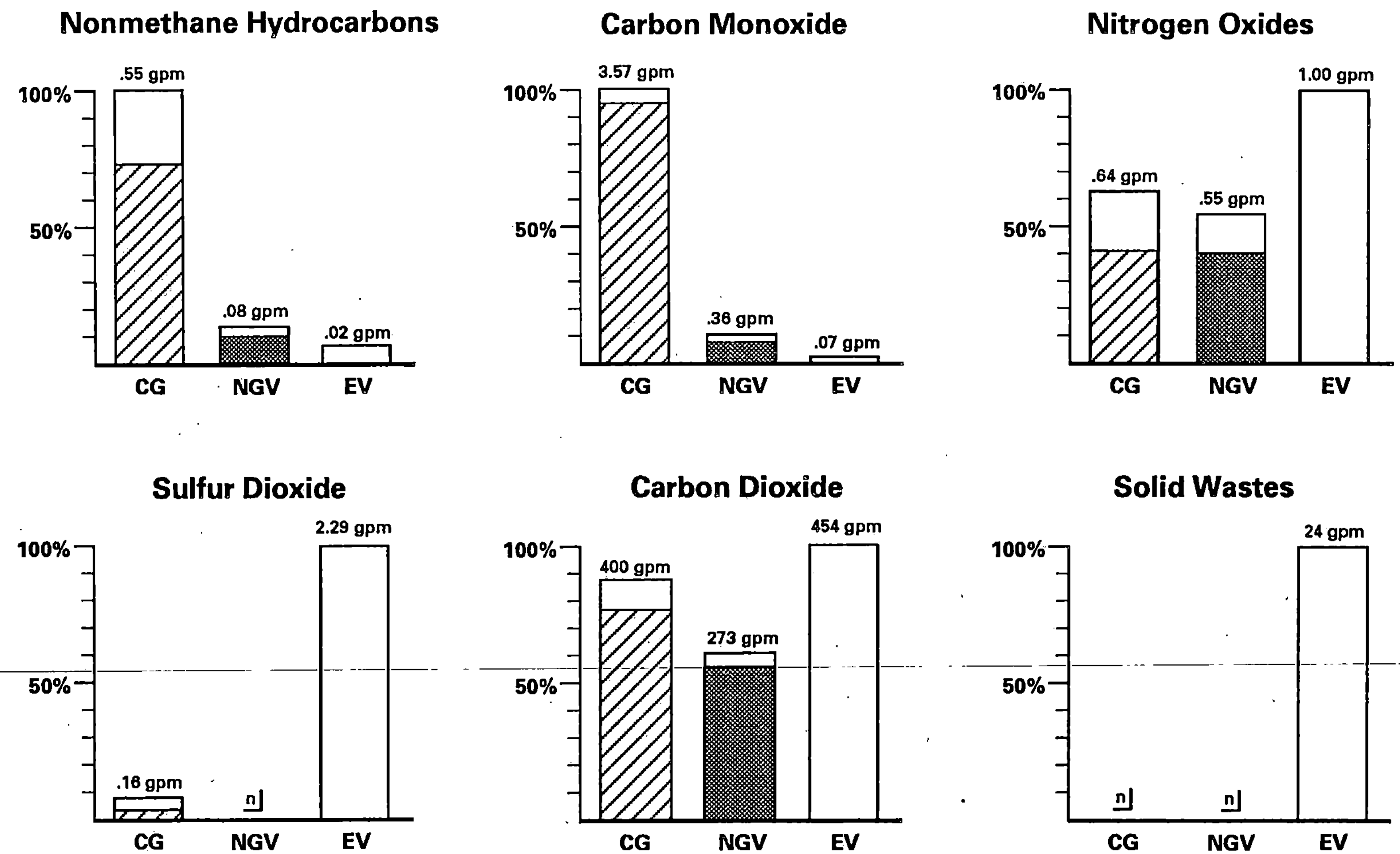
(Cents per Mile)



1 Lower end of range for electric vehicles based on 7 year battery life (129,500mi.); upper end based on 3.5 year life (64,750 mi.).

Source: See Section D-- Economic Methodology.

Exhibit 2
Vehicular and Other Emissions Attributable to Conventional Gasoline, Electric and Natural Gas Vehicles
(Index, 100 = Most Polluting Cycle)



CG: Conventional Gasoline VehicleEmissions — Vehicle ▨ Other ☐

NGV: Natural Gas Vehicle Emissions — Vehicle ▩ Other ☐

EV: Electric Vehicle Emissions — Other ☐

Note: "Other" emissions refers to emissions from production, processing, conversion, transportation and distribution of energy to vehicle.

gpm: Grams Per Mile   n : Negligible, less than .005 gpm

- Nonmethane hydrocarbons (NMHC) are one of the primary precursors of urban ozone or smog. NMHC emissions attributable to NGVs of 0.08 grams per mile (gpm) are only 15 percent of those estimated for conventional gasoline vehicles -- 0.55 gpm. Electric vehicles, with NMHC emissions of 0.02 gpm, offer even further reductions.

- Carbon monoxide (CO) is an air pollutant that is particularly troublesome in high-altitude urban areas such as Denver. NGVs can reduce CO emissions relative to conventional gasoline vehicles by 90 percent -- 0.36 gpm versus 3.57 gpm -- while CO emissions attributable to electric vehicles are 0.07 gpm.

- Nitrogen oxides (NO_x) are generally believed to be a secondary contributor to acid rain, and, in some geographic areas, ozone formation. NGVs can reduce the NO_x attributable to electric vehicles by some 45 percent -- 0.55 gpm versus 1.00 gpm -- and by some 14 percent relative to conventional gasoline vehicles (0.64 gpm).

- Sulfur dioxide (SO_2) is the primary precursor of acid rain. NGVs and their supply system produce virtually no SO_2, whereas SO_2 emissions attributable to electric vehicles and conventional gasoline vehicles are 2.29 gpm and 0.16 gpm, respectively.

- Carbon dioxide (CO_2) is the primary greenhouse gas thought to contribute to global warming. The CO_2 emissions attributable to electric vehicles -- 454 gpm -- are more than 65 percent higher than those of the NGV (273 gpm). The CO_2 of the conventional gasoline vehicle, at 400 gpm, is just over 50 percent greater than that of the NGV.

  - Methane, the primary component of natural gas, is also thought to be a contributor to global warming. Estimates regarding the climate tradeoff between NGVs and gasoline vehicles are subject to considerable uncertainties, with the climate impact of the NGV estimated to be 0-40 percent less than the gasoline vehicle, with a base case of 21 percent less.

- The generation of electricity by oil and coal also results in the production of solid waste and sludge. Solid waste production by generating units supplying energy to electric vehicles is significant, at some 24 gpm. NGVs result in no sludge or ash production.

It should be noted that the results of this analysis are dependent on a variety of assumptions regarding each of the vehicle types. (See Sections D and F -- Methodology.) In particular, emissions attributable to electric vehicles are largely dependent on the assumptions regarding how the electricity is generated. This analysis is based on the 1995 projected national average fuel mix for electricity generation -- 73 percent fossil fuels and 27 percent non-fossil (assumes no air or solid waste pollution, which overstates the benefits of renewables). The generating mix in some parts of the country, California in particular -- where electric vehicles are expected to be most successful in the short run -- is far "cleaner" than the national mix. Most electricity generated in California is via natural gas, low sulfur oil and hydro-power. This analysis overstates the environmental impacts of such areas, but understates the impacts in more coal-dependent regions. It should also be noted that the conventional gasoline vehicle used as a baseline in this analysis is significantly cleaner than a 1991 vehicle -- by 60 percent or more for some of the pollutants. Thus, the reduction potential of both NGVs and electric vehicles is even more impressive when compared with today's cars.

C. Background

The mobile source provisions of the Clean Air Act Amendments of 1990, coupled with various state programs such as the clean fuels program in California, ensure that the market penetration of clean alternatives to gasoline will increase in the 1990s. Much of this market penetration will focus on "fleet" vehicles -- e.g., taxis, delivery vans, school buses and other fleets of various types and sizes. There are some 13 million fleet vehicles in the U.S. today, accounting for about 6.5 percent of the total vehicle population and 10 percent of total vehicular energy consumption. This high energy consumption per vehicle is one of the features that makes fleets particularly attractive alternative fuel candidates. Additionally, fleets return to a central location making vehicle refueling and maintenance operationally more efficient and more economic.

The comparisons in this analysis are based on the expected performance of natural gas, electric and gasoline vehicles in the mid-1990s. Gasoline vehicles converted to natural gas are on the road today, and in most cases are cleaner than gasoline vehicles. However, light-duty vehicles dedicated to run exclusively on natural gas and optimized for natural gas operation are not yet available. Similarly, advances in electric vehicles are expected prior to any large-scale production.

This analysis is based on a light-duty minivan. This type of vehicle is suitable for fleet operations, transporting either people or light cargo. NGVs will also compete in the medium- and heavy-duty markets, but electric vehicles will probably not, due to power limitations. Fuel efficiency -- assumed equal on a Btu basis for natural gas and gasoline -- is assumed to increase to 25 miles per gallon by the mid-1990s, versus just under 20 mpg today.[2] The electric vehicle is a Chrysler TEVan, with a nickel-iron battery, and an energy consumption of 0.5

kilowatt hours per mile. The van, for which production is projected in the early 1990s, has an estimated range of 120 miles. The battery charger has an energy efficiency of 90 to 95 percent, and the battery itself is 70 to 75 percent efficient.[3]

D. Economic Methodology and Assumptions

The economic comparison presented in this analysis considers the costs of purchasing and operating a new light-duty van used for fleet-type operation. Each van considered -- gasoline, NGV or electric -- was assumed to be purchased new, driven 18,500 miles per year, and scrapped after 7 years of operation (129,500 miles) with no salvage value. This is not the typical turnover pattern of most commercial fleets, which tend to sell their vehicles before their useful life is completed, but determining the resale value of vehicles not yet in production is highly speculative.

Both the operating and capital components for all vehicles are reflective of today's costs. However, the incremental capital costs of the dedicated NGV and electric vehicle are based on the assumption of mass production by the mid-1990s.

The most problematic economic assumption is that of the useful life of batteries for electric vehicles. Batteries account for about one-third the cost of an electric vehicle, and battery replacement after one or two years would seriously reduce the competitiveness of the vehicle. Some proponents are projecting a 9- to 10-year life for nickel-iron batteries currently being developed, but not yet proven. Based on experience to date, and on the higher mileage requirement assumed in this analysis for fleet vehicles -- about double that of a passenger vehicle -- a 7-year life-span was assumed for batteries. An alternative case with a 3 ½-year life was also considered, reflecting a still significant, yet more moderate rate of technological improvement.

Vehicle Cost

The baseline gasoline vehicle is a minivan with an initial cost of $14,000 (see Exhibit 3). The NGV has an incremental capital cost of approximately $800, primarily for fuel cylinders.[4] In addition, a $200 premium was applied to the NGV due to anticipated high demand, bringing the total capital cost to $1,000. The clean fuel premium may be higher than this initially, but will taper off as the California pilot program and federal fleet programs accelerate (1996-1998) and production levels expand. The incremental cost of the electric vehicle is $7,800 -- about 97 percent of which is attributable to the batteries.[5] The electric vehicle also requires a battery charger, with a cost of roughly $100 per vehicle in fleet situations.[6] All vehicles were assumed to be purchased over 48 months at a 10 percent interest rate, with 80 percent financing and a 12 percent nominal discount factor. The present value of the costs of vehicles were allocated over the 7-year

Exhibit 3

Economic Comparison of Conventional Gasoline, Electric and Natural Gas Vehicles

Initial Capital Cost	Gasoline	Natural Gas	Electric
Base Vehicle	$14,000	$14,000	$14,000
Other	-	1,000	7,850
Total ($)	$14,000	$15,000	$21,850
(¢/mi.)	10.52¢	11.27¢	16.42¢-20.43¢
Operating Costs (¢/mi)			
Energy	3.62	1.58	2.86
Energy Tax	1.24	1.24	1.24
Compression	-	.67	-
Oil	.17	.15	-
Tires	.40	.40	.50
Maintenance	1.74	1.65	1.10
Total	7.17¢	5.69¢	5.70¢
Total Cost (¢/mi.) (Capital & Operating)	17.69¢	16.96¢	22.12¢-26.13¢[1]

Source: See Section D -- Economic Methodology.

[1]Lower end of range for electric vehicles based on 7-year battery life; upper end based on 3 ½-year life.

129,500 mile life. The cost per mile of the gasoline vehicle is 10.5¢, roughly 5 percent less than the NGV's cost of 11.3¢. The per-mile vehicle cost of the electric vehicle is 16.4¢ assuming a 7-year battery life, and 20.4¢ assuming a 3½-year life -- 56 to 94 percent greater than that of the base gasoline vehicle.

Energy Costs

The greatest expense associated with operating a vehicle is the cost of purchasing energy -- gasoline, natural gas or electricity. A 1990 gasoline cost of 90.4¢ per gallon (excluding taxes),[7] coupled with a fuel efficiency of 25 mpg, translates into an energy cost of 3.6¢ per mile for the base vehicle.

Natural gas was assumed to be sold through a slow-fill fleet-operated refueling station at the national average 1990 industrial gas rate for gas utility sales of $3.15 per MMBtu, excluding compression, see below.[8] Although dedicated NGVs may require fewer Btu per mile than comparable gasoline vehicles in the mid-1990s, supporting data is not demonstrable at this time and an equivalent fuel efficiency was assumed. The fuel cost per mile for NGVs is therefore 1.6¢ -- only about 45 percent of the gasoline vehicles fuel cost.

Electric vans were assumed to require 0.5 kilowatt hours (kwh) per mile,[10] with 30 percent of the power purchased at the 1990 national average commercial rate of 7.4¢ per kwh,[11] and the remaining 70 percent purchased at an off-peak rate of 5¢ per kwh. Some proponents assume electric vehicles will only recharge at night and pay about one-third less for electricity. This assumption seems unreasonable based on the operating characteristics of fleet vehicles. The 70 percent off-peak recharging assumed herein is reasonable, and probably generous. Based on these energy requirements and prices, both of which appear optimistic, the energy component is 2.9¢ per mile -- 20 percent less than for the gasoline vehicle, but 80 percent more than for the NGV.

The current national average gasoline tax -- combined state and federal -- is 31¢ per gallon, or 1.2¢ per mile. Federal gasoline taxes, as well as those in some states, are not currently applied to NGVs or electric vehicles. One could argue that this exclusion should continue in order to stimulate the development of these clean alternatives to imported oil. However, a conservative assumption was made that the per mile tax on each vehicle would eventually be the same, based in part on the budgetary pressure faced by many state highway departments. (On a Btu-per-mile basis, the NGV and gasoline vehicles were assumed to be equal, while electric vehicles powered by fossil fuel-based electricity would require about 15 percent more Btu into the generating station.)

The final fuel cost component, applicable only to NGVs, is attributable to the cost of compressing and dispensing natural gas at the refueling station. This analysis assumes that fleet operators will refuel NGVs in a slow-fill mode as opposed to a more costly 5 minute quick-fill. The slow fill mode requires less compression, although it is hoped that quick-fill refueling as economic as the slow fill included herein will be available in the mid- to late-1990s. Advances in compression equipment, and the proliferation of high volume, low cost public refueling stations will decrease the cost of quick fill operations. There are approximately 125 public NGV refueling stations operational in the U.S. today.[9] The slow-fill refueling cost, based on recovering both the capital cost of building the station and associated operating costs, is roughly $1.35 per million Btu (MMBtu)[12] of fuel dispensed, or 0.7¢ per mile of vehicular travel.

Other Operating Costs

The maintenance and repair costs associated with fleet gasoline vehicles is 1.7¢ per mile, with an additional 0.2¢ per mile for oil changes.[13] The combined cost for NGVs is 1.8¢ per mile, about 10 percent lower for oil changes and 5 percent lower for other maintenance. The electric vehicle requires no oil changes, and other maintenance is about two-thirds that of the base gasoline vehicle based on various published studies.[14]

Tire replacement for the base gasoline vehicle costs 0.4¢ per mile[15] versus 0.5¢ per mile for the electric vehicle. The higher replacement rate for the electric vehicle is due to its greater weight -- about 25 percent -- attributable to the batteries. The NGV would also have incremental weight due to the fuel cylinders, but tanks in the mid 1990s will be lighter, and this incremental weight will be offset by the removal of the gasoline tank and the lower weight of natural gas relative to gasoline. Thus, tire costs were assumed equal for NGVs and gasoline vehicles.

E. Economic Conclusions

The total cost of purchasing and operating an NGV is 17.0¢ per mile, about 4 percent less than the cost of the gasoline vehicle (17.7¢ per mile), and 23 to 35 percent less than the cost of the electric vehicle (22.1 to 26.1¢ per mile). The operating costs of the NGV and electric vehicle are similar, at 5.7¢ per mile, about 20 percent less than the gasoline vehicle -- 7.2¢ per mile. This operating cost savings more than offsets the $1,000 incremental capital cost of the NGV, but not the $7,850 incremental cost of the electric vehicle.

A simple payback analysis indicates that the additional cost of the NGV would be recovered in less than 3 years of operating savings. Payback analyses are very rough indicators, and vary greatly from vehicle to vehicle. NGVs with less costly cylinders, greater mileage requirements, higher fuel efficiency or those not subject to full taxation would have significantly shorter payback periods.

F. Environmental Methodology and Assumptions

Clean fuel vehicles will differ with respect to the types of pollution they can reduce, the degree of reduction they can achieve, and the location of the pollution they produce. The latter point is clearly demonstrated by electric vehicles which produce no tailpipe emissions, yet cannot be viewed as pollution free. For example, the generation of coal-fired electricity produces a variety of air, water and solid waste pollutants, as does the production, processing and transportation of the required fossil fuel to the generating station.

The purpose of this environmental analysis is to quantify the vehicular and other pollutant emissions associated with NGVs and electric vehicles relative to a conventional gasoline vehicle. The comparison is based on "typical" fleet vehicles expected to be in operation by the mid-1990s, and complying with or exceeding the emission requirements that will then be in place.

This analysis compares the energy consumption and environmental impacts not only of the vehicle itself, but also of the fuel production, processing, transportation and conversion "trajectory." Total environmental impacts depend on both the efficiency of the various segments of the trajectory, as well as the emissions of those segments. That is, less efficient vehicles require a greater energy input, which in turn requires greater levels of fuel production, processing, etc. -- with greater resultant emissions.

Conventional Gasoline Vehicles

The baseline vehicle in this analysis is assumed to run on conventional gasoline, as opposed to the "reformulated" gasoline that will be required in nine urban areas in the latter half of the 1990s. Little public data is available regarding the emission reduction potential of reformulated gasoline. The baseline vehicle is far cleaner than today's gasoline vehicle; however, emission standards will be much tighter for all vehicles purchased in the U.S. in the mid-1990s.

NMHC emissions of the gasoline vehicle were estimated at 0.40 gpm based on the tailpipe standard of 0.25 gpm, added to evaporative emissions of 0.15 gpm[16] (see Exhibit 4). These figures reflect the fact that refueling evaporative emissions must be reduced by 95 percent according to the Clean Air Act Amendments, while hot soak and running evaporatives will be required to be controlled to the "greatest extent possible." Non-vehicle NMHC emissions, primarily from the refining process, are 0.15 gpm,[17] bringing the total to 0.55 for the vehicle and its fuel supply trajectory.

Tailpipe emissions of CO from gasoline vehicles are very high -- 3.40 gpm of the 3.57 gpm total for the gasoline trajectory. This is despite the reduction in the CO standard for gasoline vehicles to 3.40 gpm from today's level of more than 10 gpm.

NO_x emissions of the gasoline trajectory total 0.64 gpm, split between tailpipe and other emissions at a rate of roughly 2:1. The total is about two-thirds that of the electric vehicle, but about 15 percent greater than the NGV due to higher non-vehicle emissions.[18] The tailpipe emissions of gasoline vehicles and NGVs are assumed to be equal at the standard of 0.4 gpm.

SO_2 emissions are quite low for the gasoline trajectory -- 0.16 gpm. Only 0.04 gpm is from the tailpipe; three-fourths of the total is from non-tailpipe sources, primarily the refinery.[19]

Over 85 percent of the 400 gpm CO_2 total is attributable to the tailpipe emissions of the gasoline vehicle. Tailpipe CO_2 emissions are based on a factor of 19 pounds of CO_2 per gallon of gasoline consumed.[20]

Estimates were not available for the solid wastes attributable to the gasoline vehicle trajectory, and they were therefore assumed to be negligible. Some sludge would result from oil storage and processing, but the amount would be minimal on a gpm basis.

Natural Gas Vehicles

Tailpipe NMHC emissions of 0.07 gpm were estimated for NGVs. This emission rate, which is below the federal fleet standard and would comply with the California Low Emission Vehicle standard, is believed achievable in the time frame of this analysis based on testing of vehicles <u>not</u> dedicated for natural gas operation, and also on projections of the Environmental Protection Agency (EPA).[21] The NMHC total is 85 percent less than the gasoline total, but slightly higher than the electric vehicle total.

NGVs have been proven to have very low CO emissions relative to gasoline vehicles. A 90 percent reduction from the gasoline standard was assumed herein, based on various vehicle test results and studies by EPA.[22] The CO total is 0.36 gpm, with a minimal contribution of 0.02 gpm from non-tailpipe emissions.

NO_x is one of the more difficult pollutants to control in NGVs, especially when the emissions of other pollutants are also held at very low levels. It was assumed that NGVs would do no better than the Phase I standard of 0.4 gpm, the same as gasoline vehicles. An additional 0.15 gpm of NO_x is attributable to other segments of the natural gas trajectory, primarily from compressor stations used in gas transportation. Compressor station NO_x emissions from EPA's AP 42[23] of 1.3

Exhibit 4

Vehicular and Other Emissions Attributable to Gasoline and Alternative Fuel Vehicles
(grams per mile)

	Natural Gas			Electric			Gasoline		
	Vehicle	Other	Total	Vehicle	Other	Total	Vehicle	Other	Total
NMHC	.07	.01	.08	--	.02	.02	.40	.15	.55
CO	.34	.02	.36	--	.07	.07	3.40	.17	3.57
NO_x	.40	.15	.55	--	1.00	1.00	.40	.24	.64
SO_2	n	n	n	--	2.29	2.29	.04	.12	.16
CO_2	261	12	273	--	454	454	345	55	400
Solid Waste	n	n	n	-	24	24	n	n	n

Source: See Section F, Environmental Methodology.
n: Negligible, less than .005 gpm
NMHC: Nonmethane hydrocarbons
CO: Carbon monoxide
NO_x: Nitrogen oxides
SO_2: Sulfur dioxide
CO_2: Carbon dioxide
Solid Waste: Sludge and ash

grams/brake horsepower-hour for turbines and 11 grams/brake horsepower-hour for reciprocating engines was assumed. Operating hours in 1988 of 16.6 billion horsepower-hours for turbines and 39.1 billion for engines was assumed based on data collected by A.G.A. Total NO_x emitted was calculated and divided by gas throughput in 1988, and converted to grams per mile of vehicular travel.

CO_2 emissions of 273 gpm were calculated for NGVs, about 20 and 40 percent less than the CO_2 emissions attributable to the gasoline and electric trajectories, respectively. Ninety-six percent of the NGVs CO_2 emissions are attributable to the vehicle, based on an emission rate of 115 pounds of CO_2 per MMBtu of fuel consumed.[24] The remaining 12 gpm is largely from pipeline compressor stations, which consume about 3.8 percent of the total gas throughput.

Assuming a global warming potential (gwp) (mass basis -- 100-year horizon) of 21,[25] a one percent loss[26] rate for natural gas operations, and 1 gpm of tailpipe methane emissions, the net effect of using natural gas as a vehicular fuel instead of gasoline would be approximately a 21 percent reduction in the greenhouse impact of the vehicle. Assuming a very conservative gwp of 60 the NGV and gasoline alternatives would be equal from a climate perspective, while the NGV would be superior by 40 percent, assuming a 25 percent improvement in NGV efficiency compared with the gasoline vehicle.

The NGV trajectory produces no CO_2, sludge or ash. NGVs are also expected to reduce tailpipe toxic emissions by some 90 percent according to EPA, a point not explored in this analysis.[25]

Electric Vehicles

There are no air or solid waste emissions from the electric vehicle itself. Thus, total emissions attributable to the electric vehicle are primarily dependent on the energy source used to generate the electricity, and the pollution controls, if any, at the generating site. If all electricity were supplied by solar, wind or hydro power, the electric vehicle would be pollution-free from the standpoint of the pollutants considered in this analysis. On the other hand, if all electricity were provided by uncontrolled high sulfur coal units, the electric vehicle would be far from environmentally benign. For example, the generating mix in California is far "cleaner" than the mix in most other states. Therefore electric vehicles, which are expected to be initially most successful in California, will have less adverse environmental impacts there than in other states.

This analysis is based on the assumption that electricity will be supplied by the national average generating mix projected to be in-place in 1995 -- which is only slightly different from that which is in-place today. About 90 gigawatts (GW) of capacity is projected to be added by 1995 to the currently in-place total of 750

GW.[28] It is projected that some 60 GW will be electric utility capacity, split between natural gas, coal and "other" sources at roughly one-third each. Non-utility generators will add about 30 GW, with some three-fourths of this capacity gas-fired and the bulk of the remainder coal-fired. In all, the portion of electricity provided by gas will increase to 13 percent from today's 9 percent level. The oil share will drop slightly, but remain at just over 5 percent, while coal drops from 57 to 55 percent. "Other" sources, including nuclear, hydro and miscellaneous sources, fall from 28 to 27 percent of the total. Thus, 27 percent of the energy supplied to the electric vehicle was assumed to be pollution free. The remainder was assumed to be controlled to at least the extent required by law.

Emissions of NMHC and CO attributable to the electricity trajectory are extremely low -- 0.02 gpm and 0.07 gpm, respectively. Emissions of the conversion segment were taken from EPA's AP-42,[29] all other emissions were derived from Hittman.[30] NO_x emissions of 1.00 gpm attributable to electric vehicles are significant. Over 97 percent of the NO_x total comes from generating units. Existing uncontrolled oil and gas boilers each emit roughly a half a pound of NO_x per MMBtu, while uncontrolled coal boilers emit a full pound. New gas and oil units were assumed to be combined cycle plants with reduced emissions of 0.15 pounds per MMBtu. New coal units and existing units "affected" by the clean air act Phase I requirements were assumed to meet the required low NO_x burner rate of 0.5 pounds per MMBtu. The overall weighted average for fossil fuel units is 0.75 pounds per MMBtu, and zero for all other units.

Sulfur dioxide emissions attributable to the electric vehicle -- 2.29 gpm -- are far higher than the natural gas or gasoline options. Virtually all of these emissions are from the generating plant. The current weighted average SO_2 emission rate for fossil fuel generating units is approximately 1.65 pounds per MMBtu, projected to drop to 1.2 pounds per MMBtu[31] as more gas and new controlled coal units are added, in addition to the retrofitting of existing coal units required by the clean air act amendments.

Emissions of CO_2 attributable to electric vehicles are 454 gpm, about the same as the conventional gasoline total and 66 percent greater than those attributable to the NGV. Roughly three-fourths of the CO_2 emissions are attributable to the generating plant, the remainder is primarily attributable to oil refinery operations and the transportation of gas, oil and coal to the generating unit. The carbon content of the fuel determines the CO_2 emission level -- approximately 115 pounds per MMBtu for natural gas, 170 pounds per MMBtu for residual oil, and 206 pounds per MMBtu for coal.[32]

Electricity generation via coal or oil produces significant amounts of solid waste in the form of sludge and ash. (Electric vehicles may also produce a solid waste problem as a result of battery disposal, but the magnitude of this problem is, as yet, unclear, and not treated in this analysis.) Sludge is a semi-solid waste that results primarily from SO_2 scrubbers and liquid waste treatment processes. Approximately 1 acre/foot is produced annually per megawatt of scrubbed generating capacity.[33] Ash is also produced as a result of coal combustion, collected both in electrostatic precipitators and in boilers as bottom ash. A combined solid-waste total of 950,000 tons per year per 1,000 MW for scrubbed coal units, 450,000 tons per year per 1,000 MW for residual oil units, and 250,000 tons per year per 1,000 MW for unscrubbed coal units, was used.[34] No solid waste was assumed to originate from gas or other units. Based on an average of 18,500 miles per year per vehicle, these solid waste totals translate to some 24 gpm.

G. Environmental Conclusions

Significant reductions in the emissions of air pollutants associated with urban air quality -- NMHC, CO and NO_x -- are achievable by substituting NGVs and/or electric vehicles for conventional gasoline vehicles. These air quality improvements are achievable in spite of the fact that the gasoline vehicle of the mid-1990s will be far cleaner than that available today. Electric vehicles result in somewhat lower emissions of NMHC and CO relative to NGVs, while the opposite is true for NO_x. (In fact, NO_x emissions of the electric vehicle trajectory are about 35 percent higher than the conventional gasoline trajectory.) In terms of global warming (CO_2), acid rain (SO_2) and solid waste disposal, NGVs are clearly superior to either electric or conventional gasoline vehicles.

Footnotes

[1]American Gas Association, Projected Natural Gas Demand From Vehicles Under the Mobile Source Provisions of the Clean Air Act Amendments, Energy Analysis 1991-2, (Arlington, VA: Jan 30, 1991) p. 4.

[2]U.S. Department of Energy, Office of Policy, Planning and Analysis, Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U. S. Transportation Sector, Technical Report Four, (Washington, DC: August 1990) p. 6.

[3]DeLuchi, Wang and Sperling, "Electric Vehicle: Performance, Life-Cycle Costs, Emissions and Recharging Requirements," published in Transpor. Res., -A," Vol. 23A, No. 3., (Great Britian, 1989), pp. 255-279.

[4]U.S. Department of Energy, Op. Cit, p. 30.

[5]U.S. Department of Energy, Op. Cit, p. 43.

[6]DeLuchi, Wang and Sperling, Op. Cit, p. 263.

[7]U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, (Washington, DC: February 1991) p.74. Price of 116.4¢/gal. for unleaded regular minus 26¢/gal. taxes.

[8]American Gas Association, Monthly Gas Utility Statistical Reports, (Arlington, VA: various issues, data for December preliminary).

[9]American Gas Association, Directory of Natural Gas Vehicle Refueling Stations Products and Services, (Arlington, VA: February 1991).

[10]U.S. Department of Energy, Op. Cit, p. 42.

[11]U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, (Washington, DC: February 1991) p. 101.

[12]American Gas Association, An Analysis of the Economics and Environmental Effects of Natural Gas as an Alternative Fuel, Energy Analysis 1989-10, (Arlington, VA: Dec. 15, 1989) p. 7.

[13]Bobit Publications, Automotive Fleet Fact Book, (Redondo Beach, CA: 1988) p. 23.

[14]DeLuchi, Wang and Sperling, Op. Cit, p. 264.

[15]Bobit Publications, Op. Cit, p. 28.

[16]Evaporative emissions from refueling assumed to drop by 95 percent from today's level (.07 gpm) as required by clean air act. Hot soak and running losses, which must be controlled to the greatest extent possible, assumed to drop by more than 50 percent based on discussions with EPA.

[17]Hittman Associates for National Science Foundation, EPA and CEQ, Environmental Impact, Efficiency and Cost of Energy Supply and End-Use, (Columbia, MD: November 1974).

[18]Ibid.

[19]Ibid.

[20]David Gushee, Congressional Research Service Report to Congress, Carbon Dioxide Emissions From Methanol as a Vehicle Fuel, (Washington, DC: January 1989) p. 4.

[21]Christopher Weaver, Natural Gas Vehicles and the Environment, Summary Report, preliminary draft, (Rancho Cordova, CA: August 1990) p. 15.

[22]U.S. Environmental Protection Agency, Office of Mobile Sources Analysis of the Economic and Environmental Effects of Compressed Natural Gas as a Vehicle Fuel, Vol. I, (Washington, DC: April 1990) p. 31.

[23]U.S. Environmental Protection Agency, OAQPS, Compilation of Air Pollutant Emission Factors, (Research Triangle Park, NC: August 1977) p. 3.3.2-2.

[24]American Gas Association, Identification of Errors in Science Concepts, Inc. Greenhouse Paper, Issue Brief 1989-13, (Arlington, VA: Aug. 25, 1989).

[25]ICF Incorporated for U.S. EPA, Preliminary Technical Cost Estimates of Measures Available to Reduce U.S. Greenhouse Gas Emission, (Fairfax, VA: August 1990) p. 4.

[26]Intergovernmental Panel on Climate Change, Methane Emissions and Opportunities for Control, (Washington, DC: September 1990).

[27]U.S. Environmental Protection Agency, Office of Mobile Sources, Op. Cit, p. 33.

[28]North American Electric Reliability Council, Electricity Supply and Demand 1989-1998, (Princeton, NJ: October 1989).

[29]U.S. Environmental Protection Agency, OAQPS, Compilation of Air Pollutant Emission Factors, Supplement A, (Research Triangle Park, NC: October 1986).

[30]Hittman, Op. Cit.

[31]Based on emission of 2 pounds per MMBtu from coal units today (scrubbed plus uncontrolled), 1 pound per MMBtu from oil units, and no SO_2 from natural gas units. SO_2 emissions from existing coal units assumed to decline by 4.3 million tons per year by 1995.

[32]American Gas Association, Identification of Errors in Science Concepts, Inc. Greenhouse Paper, Issue Brief 1989-13 (Arlington, VA: August 25, 1989).

[33]U.S. Department of Energy, Office of Fossil Energy, Americas Clean Coal Commitment, (Washington, DC: February 1987) p. A-4.

[34]U.S. Department of Energy and U. S. Environmental Protection Agency, Energy/Environment Fact Book, (Washington, DC: March 1978) p. 24.

American Gas Association

Energy Analysis

1515 Wilson Boulevard
Arlington, Virginia 22209

A.G.A. Planning & Analysis Group

EA 1991-2

January 30, 1991

PROJECTED NATURAL GAS DEMAND FROM VEHICLES UNDER THE MOBILE SOURCE PROVISIONS OF THE CLEAN AIR ACT AMENDMENTS

A. Introduction

The Clean Air Act Amendments of 1990 are one of the most far-reaching environmental initiatives ever passed in this country. These amendments contain a number of sections germane to the natural gas industry, in particular, the mobile source, acid rain and ozone non-attainment provisions.

The mobile source program has three major components or tiers. First, conventional gasoline and diesel-powered vehicles sold throughout the U.S. will face tougher emissions standards starting in 1994. Second, in the country's nine smoggiest cities, all conventional gasoline will be replaced by reformulated gasoline. Third and most important to the gas industry, there is a program to promote the use of clean vehicular fuels as an alternative to gasoline. There is a federal program that mandates that fleets in 22 urban areas purchase clean fuel vehicles, in addition to an ambitious pilot program in California. Urban buses will also be required to be much cleaner. If buses can't be adequately cleaned with an unproven particulate trap and lower sulfur diesel fuel, they too will be subject to a stringent clean-fuel program.

The purpose of this analysis is to estimate the incremental demand for natural gas attributable to the mobile source provisions of the legislation.

B. Executive Summary

This analysis projects that the incremental demand for natural gas directly attributable to the mobile source provisions of the Clean Air Act Amendments of 1990 will reach 600 billion cubic feet (Bcf) by 2005 in a Base Case, and 300-1,000 Bcf in Low and High Cases, respectively (see Exhibit 1).

- Exhibit 2 illustrates how many clean fuel vehicles will be purchased and put in service between 1995 and 2005 as a result of the Clean Air Act fleet program and the California pilot program, based on A.G.A. projections. It includes all clean-fuel vehicles regardless of fuel type -- methanol, ethanol, propane, electricity, natural gas or whatever else can meet the standard. The minimum level is 4.5 million vehicles in 2005, with a maximum of 9.7 million in that same year.

  - The minimum is based on the estimated number of total purchases annually in the 22 cities, as required by the law. The maximum assumes that all non-covered fleets in the U.S. opt-in to the program on a voluntary basis, in the same manner and at the same rate as covered fleets.

  - Natural gas is projected to capture a 75 percent market share in light-duty and medium-duty fleet trucks in the Base Case. The projected market share in the Base Case for fleet cars is lower -- 40 percent -- as a result of competition from methanol and reformulated gasoline. Heavy trucks and buses, which involve far fewer vehicles, have projected market shares of about 40 to 45 percent, respectively, in the Base Case.

- The analysis projects in total just under 4 million natural gas vehicles (NGVs) purchased by 2005 in the Base Case, with low and high estimates of 1.8 and 6.7 million vehicles (see Exhibit 3).

- Translating these NGVs on the road shown in Exhibit 3 into gas demand results in totals of 600 Bcf in 2005 in the Base Case, and roughly 300 Bcf to 1,000 Bcf in the Low and High Cases.

  - These projections assume a 10-year vehicle life; that is, cars purchased in 1995 will still be on the road in 2005.

- There are approximately 195 million vehicles on the road today, consuming 16.3 quadrillion Btu of energy -- almost all of which is gasoline or diesel fuel. Fleet vehicles account for 6.5 percent of the vehicle population, but 10 percent of total energy consumption (see Exhibit 4). This high consumption per vehicle for fleets is one of the chief reasons they are such an attractive target for NGVs.

- The number of natural gas vehicles forecast in this analysis is limited to those attributable to the Clean Air Act. Natural gas vehicles are currently penetrating the market on the basis of economics. In addition, governmental policy initiatives to limit oil imports could rapidly expand this market. Neither economic nor energy security factors were considered herein -- just the Clean Air Act.

Exhibit 1

NGV GAS DEMAND FROM CLEAN AIR ACT
1995 - 2005

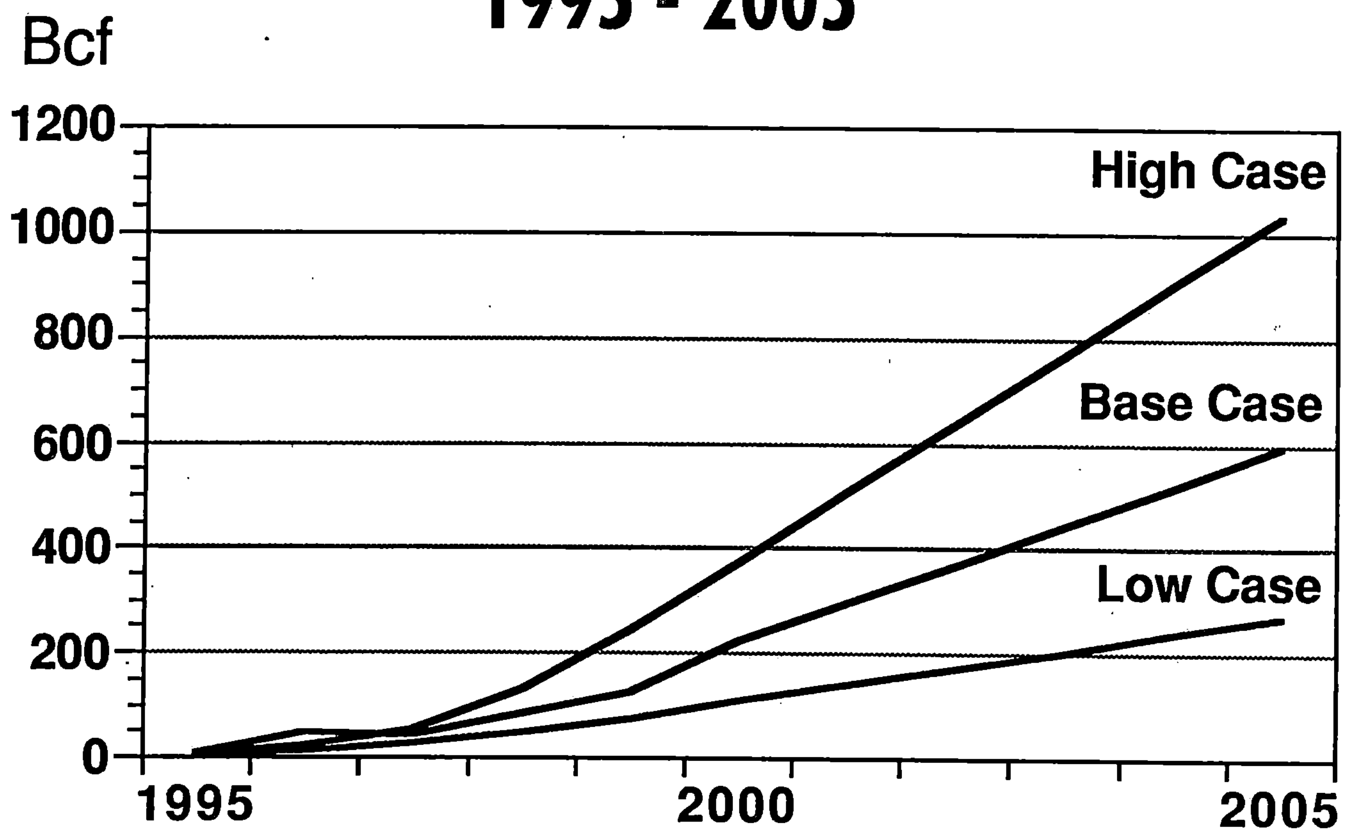


Exhibit 2

CLEAN FUEL VEHICLES ON THE ROAD
1995 - 2005

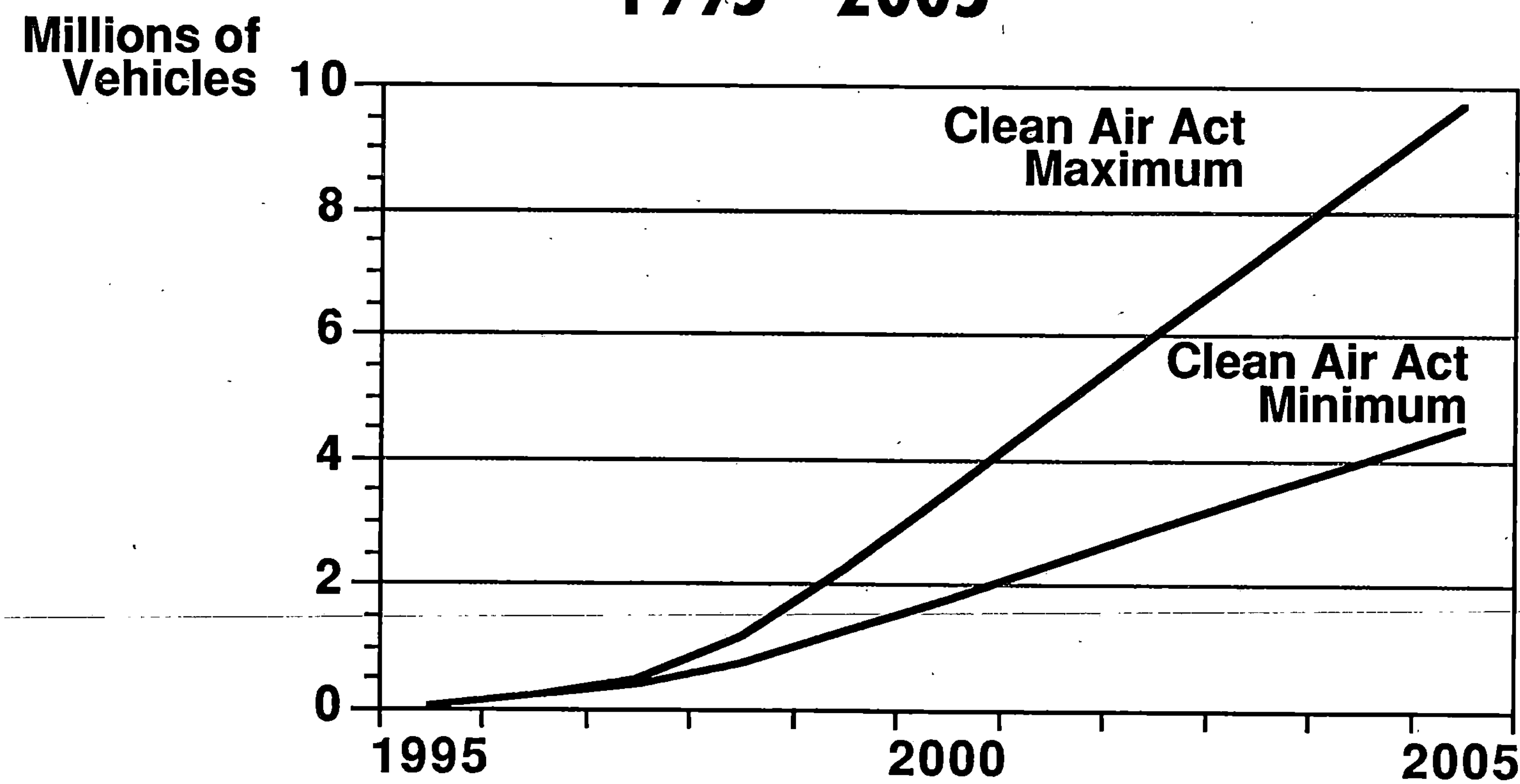


Exhibit 3

NGVs ON THE ROAD ATTRIBUTABLE TO CLEAN AIR ACT
1995 - 2005

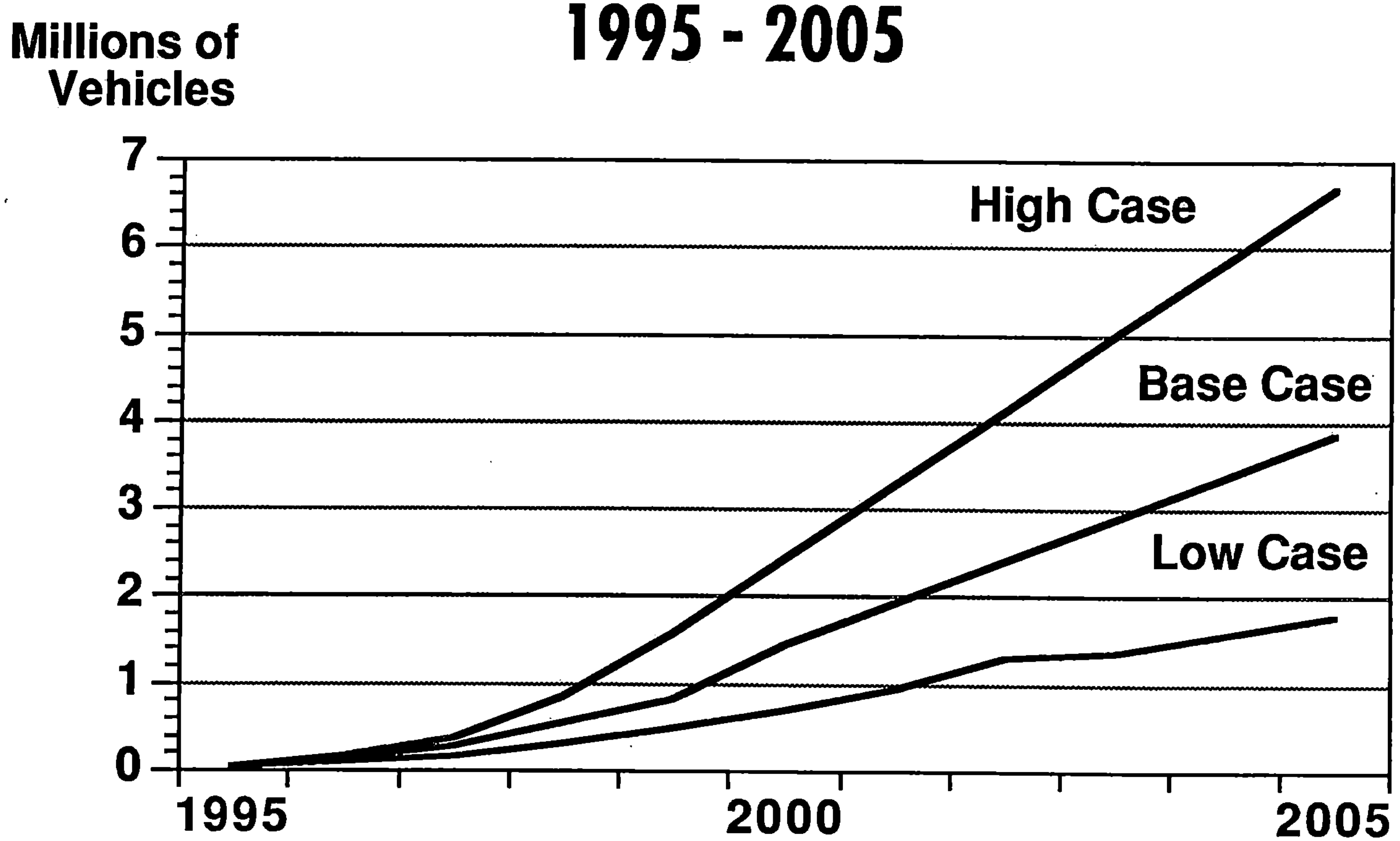
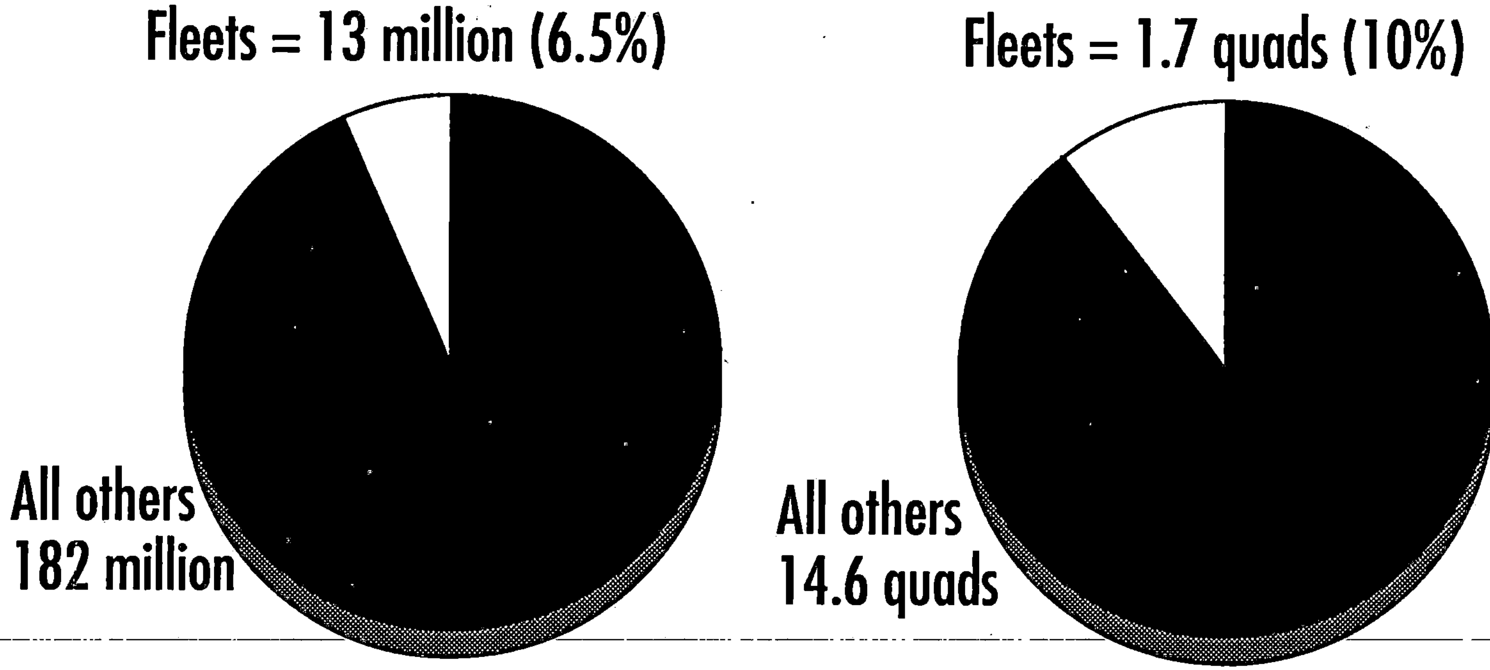


Exhibit 4

1990 VEHICLE POPULATION



195 Million Vehicles Consume 16.3 Quads

C. Background: Legislation

The general structure of the mobile source provisions of the Clean Air Act Amendments of 1990 is as follows:

1. Areas Covered by the Fleet Program

Twenty-two urban areas are covered by a clean-fuel fleet program. The program requires that certain fleets, when purchasing new vehicles, purchase clean fuel vehicles. The program does not target cities per se, but rather metropolitan statistical areas or consolidated metropolitan statistical areas, which usually include a number of counties surrounding the core cities. The total population of these 22 urban areas represents roughly one-third of the U.S. population.

Twenty-one of the areas are covered because they are in serious, severe or extreme non-attainment for ozone pollution. The final city is Denver, which is pulled in because of its severe problem with carbon monoxide pollution. Although the areas are grouped by their degree of non-attainment severity, they are all treated equally with respect to the fleet program.

2. Covered Fleets/Vehicles

"Covered fleets" include those with 10 or more vehicles; capable of central refueling, excluding various emergency, rental, demos, off-road and privately-garaged vehicles. It covers weight classes from 0 to 26,000 pounds, from the smallest passenger cars up to furniture-type vans.

3. Phase-In Schedule

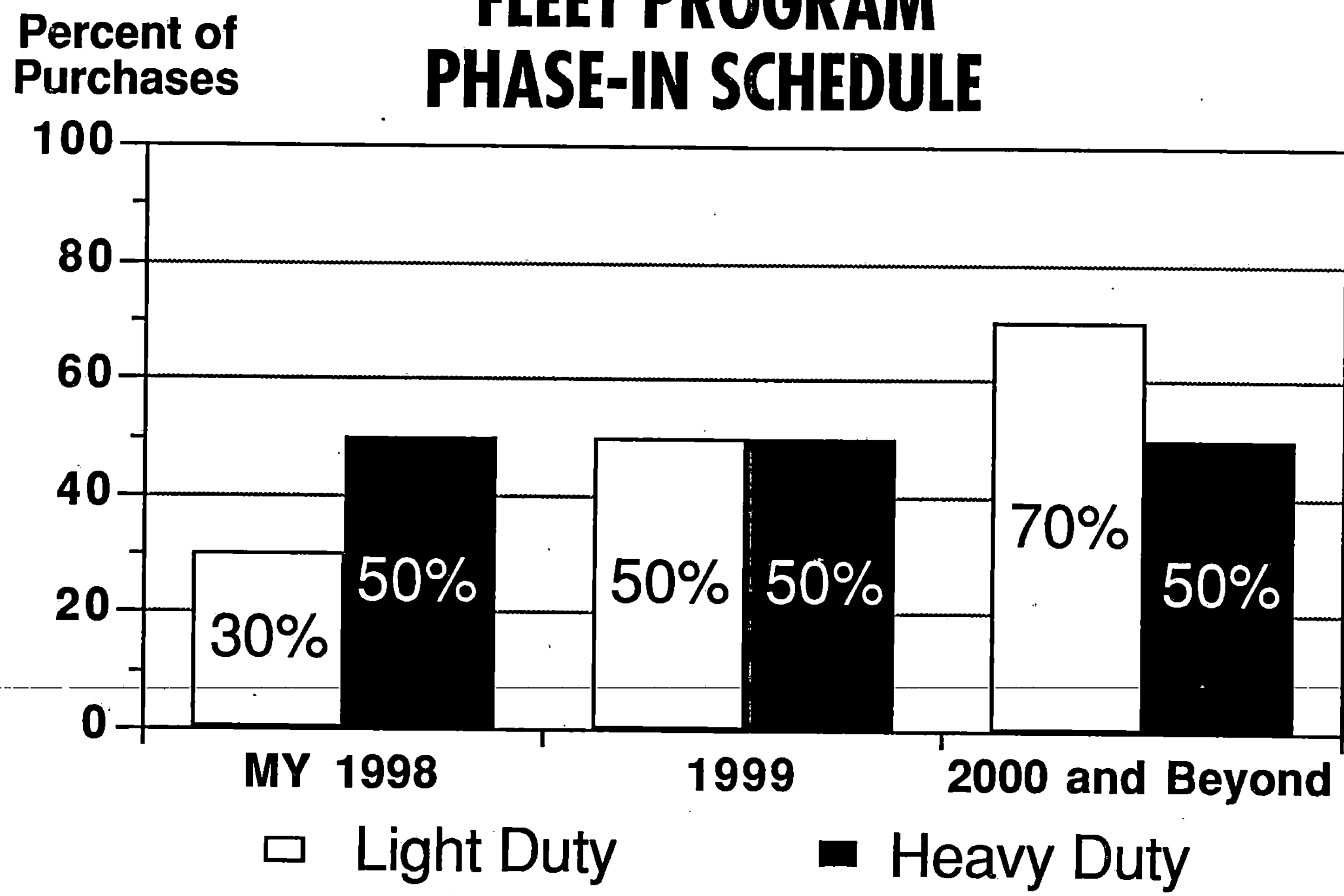
In the covered fleets, a minimum percentage of new purchases must be clean-fuel vehicles (see Exhibit 5). In model-year 1998, 30 percent of light-duty vehicles -- passenger cars and light vans less than 8,500 pounds -- must be clean-fuel, increasing to 50 percent in model-year 1999, and to 70 percent in 2000 and beyond. For the heavy-duty class, again, including buses and furniture-type vans from 14,000 to 26,000 pounds, the phase-in requirement is a constant 50 percent beginning with model-year 1998. A schedule was not set for the medium and heavier vans from 8,500 to 14,000 pounds -- this will be left up to the states.

4. Credit Program

Fleet operators who purchase more clean-fuel vehicles than required, or cleaner vehicles than required, or earlier than required, will be given tradeable credits. These credits may be saved or sold to another

Exhibit 5

FLEET PROGRAM PHASE-IN SCHEDULE



fleet with a purchase requirement. For example, assume a fleet is required to purchase 20 clean fuel vehicles, and that NGVs are twice as clean as the set standard. The fleet could satisfy its requirement by buying only 10 NGVs. Alternatively, it could buy the 20 NGVs and sell the surplus vehicle credits to another fleet in the area.

5. California Pilot Program

Clean-fuel passenger and truck vehicle pilot programs will kick-off in California in model-year 1996 -- two years earlier than the federal fleet program. The emission standards of the two programs are linked. The California program, which is limited to vehicles less than 8,500 pounds (a medium-size van), mandates the production and sale of 150,000 clean-fuel vehicles per year for model-years 1996 through 1998. For model-years 1999 and beyond, the mandate increases to 300,000 vehicles per year. The pilot program differs from the federal program in that credits are available to manufacturers for producing more or cleaner vehicles, not for fleet owners who purchase these vehicles. To ensure that Detroit would not be required to manufacture different vehicles for every state, states may voluntarily opt-in to the program, but only with vehicles that are consistent with the California program.

D. Methodology

1. Minimum Number of Clean-Fuel Vehicles

The first step in this analysis was to estimate the number of fleet vehicles purchased annually in the U.S., and to determine how many of these vehicles will be "clean-fuel" (i.e., capable of running on natural gas or some other clean fuel) based on the requirements set out in Title II of the Clean Air Act Amendments of 1990. This minimum vehicle projection for the years 1995 through 2005 is set out in detail in Appendix I, and the estimation procedure is described below.

Fleet Cars (Non-California). There are currently 10.6 million fleet cars in the U.S.[1] Approximately 4.1 million of these vehicles will be covered by the amendments, after excluding rentals, individually leased cars, emergency vehicles, etc.[1] It was estimated that 3.3 million of these are capable of central refueling, assuming central refueling capabilities of 60 to 85 percent,[2] depending on the vehicle type. With average turnover periods ranging from 31 to 61[1] months, total U.S. annual purchases are estimated at 1.1 million vehicles. Based on the population of the affected cities outside of California,[3] 23 percent of the U.S. population, this translates into annual purchases of some 258,000 vehicles. The mandatory clean-fuel light-duty vehicle shares of 30 percent in model-year 1998, 50 percent in 1999 and 70 percent in 2000 were applied to the covered fleet annual purchases of 258,000 to obtain the estimates shown in Appendix I.

It should be noted that vehicle projections in all appendices are for the total number of vehicles on the road -- i.e., vehicles on the road in 2005 are the cumulative purchases over the 10-year period. Although fleets do not hold vehicles for 10 years, it is assumed that a resale market will develop for clean-fuel vehicles, similar to that which now exists for fleet gasoline vehicles.

Fleet Light and Medium Trucks (Non-California). The estimation procedure for trucks less than 14,000 pounds was similar to that used for fleet cars. Of the total 2.2 million vehicles currently in the fleet, 2 million vehicles are covered after excluding exempt vehicles.[1] Based on central refueling capabilities of 60 to 85 percent, and average turnover periods of 60.5 months,[1] annual purchases of 327,000 light/medium trucks was estimated -- 75,000 purchases per year in the affected cities outside of California, based on population weighting.

California Pilot Program. The California pilot program requires that 150,000 alternative-fuel cars and light trucks be purchased in model-years 1996 through 1998, increasing to 300,000 in 1999 and thereafter. It was assumed that one-third of the required total would be satisfied by cars and two-thirds by light trucks, based on the more favorable economies for alternative-fuel light-duty trucks relative to cars. It was further assumed that vehicles purchased for the pilot program would satisfy the federal fleet program requirements in California.

Heavy-Duty Trucks. There are approximately 1.8 million heavy-duty trucks in the U.S. less than 26,000 pounds.[4] Based on a 10-year vehicle life, this translates into 180,000 vehicles purchased annually. It was assumed that half of these vehicles are in fleets greater than 10, and that 80 percent are centrally refuelable. Applying the population weighting for affected cities and the mandated 50 percent purchase requirement initiated in model-year 1998 results in estimates of approximately 11,000 clean-fuel heavy-duty trucks purchased annually.

Urban Buses. Approximately 4,000 urban buses are purchased annually in the U.S., roughly 60 percent of which go to cities with populations in excess of 750,000.[5] Thus, we estimate that some 2,400 clean buses will be purchased annually in the U.S.

2. Minimum Alternative Fuel Demand

The fuel demand of the minimum number of clean-fuel vehicles projected is set out in Appendix II. Both fleet cars and light fleet trucks consume approximately 150 million Btu per year, with fleet cars travelling 27,500 miles per year at 20 to 25 miles per gallon over the forecast period, and light fleet trucks travelling 18,500 miles per year at 14 to 16 miles per gallon. Heavy-duty trucks consume about 170 million Btu per year, or 1,250 gallons, based on an annual requirement of 10,000 miles per year at 8 miles per gallon. The average urban bus consumes 1,263 million Btu per year -- roughly 9,200 gallons of diesel fuel.[6]

3. Maximum Clean Fuel Vehicles and Fuel Demand

Appendix III shows the estimated maximum number of clean fuel vehicles attributable to Title II, and Appendix IV indicates the annual fuel demand of these vehicles. Appendices I and II assume that only fleets in serious, severe and extreme non-attainment areas purchase clean-fuel vehicles, as required by the legislation. The maximums in Appendices II and IV assume that all fleets in the U.S. voluntarily opt-in to the federal program at the same rate and on the same schedule as those covered fleets in the 22 cities. Some states have already announced that they intend to opt-in, and others will surely follow as clean-fuel vehicles will provide one of the best options available to escape the various sanctions that could be placed on areas which fail to achieve attainment.

4. NGVs on the Road

Appendices V, VI and VII set out the Low Case, Base Case and High Case projections for natural gas vehicles on the road attributable to Title II. These projections were made based on the following market shares applied to the previously discussed estimate for all clean-fuel vehicle purchases:

Projected NGV Market Shares

	Low Case	Base Case	High Case
Fleet Cars	30%	40%	60%
Fleet Light/Med Trucks	50%	75%	85%
Fleet Heavy Trucks	10%	40%	70%
Urban Buses	10%	45%	80%

Light and medium-duty trucks and vans are expected to be the most attractive market for NGVs, based on their operating characteristics and greater space available for fuel cylinders. The fleet car market shares are modestly lower than those for light and medium trucks due to less fuel storage space and anticipated greater competition from reformulated gasoline, methanol and other alternatives. Heavy duty truck and urban bus shares for natural gas range from very low to very high. It is unclear whether mechanical modifications, such as particulate traps for buses, will prove viable options for meeting the mandates of the legislation. If they are not, natural gas will capture the lion's share of these markets.

5. Gas Demand for NGVs

The gas demand from the NGVs attributable to the Clean Air Act Amendments -- Low Case, Base Case and High Case -- are presented in Appendices VIII, IX and X. These consumption levels are based on the same per-vehicle requirements described above -- 150 MMBtu per year for fleet cars and light trucks, 170 MMBtu per year for heavy duty trucks, and 1,263 MMBtu per year for urban buses.

Footnotes

[1] Bobit Publishing Company, 1990 Automotive Fleet Fact Book, Vol. 29 supplement, (Redondo Beach, CA: 1990).

[2] Runzheimer International, Survey and Analysis of Business Car Policies and Costs, 1989-1990, (Northbrook, IL: 1989). Survey results modified by A.G.A. based on 1989 phone survey to reflect legislation intent to target vehicles "capable of central refueling" not just those that are centrally refueled.

[3] U.S. Bureau of the Census, U.S. Statistical Abstract, 1989, (Washington, DC: 1990).

[4] U.S. Bureau of the Census, Truck Inventory and Use Survey, (Washington, DC: August 1990).

[5] American Public Transit Association, 1990 Operating and Financial Statistics, (Washington, DC: November 1990), and A.G.A. phone discussion with APTA, December 1989.

[6] U.S. Department of Transportation, National Transportation Statistics, (Washington, DC: July 1990).

APPENDIX I

Minimum Clean Fuel Fleet Vehicles on the Road Due to Clean Air Act
1995-2005
(Thousands)

	Fleet Cars			Light/Medium Trucks					
	California	Non-California	Total	California	Non-California	Total	Heavy Duty Trucks	Urban Buses	Total
1995	15	-	15	30	-	30	-	-	45
1996	65	-	65	130	-	130	-	-	195
1997	115	25	140	230	7	237	3	.7	380
1998	180	120	300	365	35	400	14	1.4	715
1999	280	285	565	565	78	643	25	2.6	1,236
2000	380	465	845	765	131	896	36	4.3	1,781
2001	480	645	1,125	965	184	1,149	47	6.7	2,328
2002	580	825	1,405	1,165	237	1,402	58	9.1	2,874
2003	680	1,005	1,685	1,365	290	1,655	69	11.5	3,420
2004	780	1,185	1,965	1,565	343	1,908	80	13.9	3,967
2005	880	1,365	2,245	1,765	396	2,161	91	16.3	4,513

APPENDIX II

Minimum Fuel Demand of Clean Fuel Fleet Vehicles Attributable to Clean Air Act
1995-2005
(Bcf-Equivalent)[1]

	Fleet Cars			Light/Medium Trucks					
	California	Non-California	Total	California	Non-California	Total	Heavy Duty Trucks	Urban Buses	Total
1995	2.2	-	2.2	4.5	-	4.5	-	-	6.7
1996	9.8	-	9.8	19.5	-	19.5	-	-	29.3
1997	17.2	3.8	21.0	34.5	1.0	35.5	.5	.9	57.9
1998	27.0	18.0	45.0	54.8	5.2	60.0	2.4	1.8	109.2
1999	42.0	42.8	84.8	84.8	11.7	96.5	4.2	3.3	188.8
2000	57.0	69.8	126.8	114.8	19.6	134.4	6.1	5.4	272.7
2001	72.0	96.8	168.8	144.8	27.6	172.4	8.0	8.5	357.7
2002	87.0	123.8	210.8	174.8	35.6	210.4	10.0	11.5	442.7
2003	102.0	150.8	252.8	204.8	43.5	248.3	11.7	14.5	527.3
2004	117.0	177.8	294.8	234.8	51.4	286.2	13.6	17.6	612.2
2005	132.0	204.8	336.8	264.8	59.4	324.2	15.5	20.6	697.1

[1]One Bcf equals approximately 1.03 trillion Btu.

APPENDIX III

Maximum Clean Fuel Fleet Vehicles on the Road Due to Clean Air Act
1995-2005
(Thousands)

	Fleet Cars			Light/Medium Trucks					
	California	Non-California	Total	California	Non-California	Total	Heavy Duty Trucks	Urban Buses	Total
1995	15	-	15	30	-	30	-	-	45
1996	65	-	65	130	-	130	-	-	195
1997	115	85	200	230	28	258	12	1.2	471
1998	180	450	630	365	135	500	48	2.4	1,180
1999	280	1,015	1,295	565	300	865	84	4.4	2,248
2000	380	1,714	2,094	765	504	1,269	120	7.2	3,490
2001	480	2,413	2,893	965	708	1,673	156	11.2	4,733
2002	580	3,111	3,691	1,165	911	2,076	192	15.2	5,974
2003	680	3,810	4,490	1,365	1,115	2,480	228	19.2	7,217
2004	780	4,509	5,289	1,565	1,319	2,884	264	23.2	8,460
2005	880	5,207	6,087	1,765	1,523	3,288	300	27.2	9,702

APPENDIX IV

Maximum Fuel Demand of Clean Fuel Fleet Vehicles Attributable to Clean Air Act
1995-2005
(Bcf-Equivalent)[1]

	Fleet Cars			Light/Medium Trucks					
	California	Non-California	Total	California	Non-California	Total	Heavy Duty Trucks	Urban Buses	Total
1995	2.2	-	2.2	4.5	-	4.5	-	-	6.7
1996	9.8	-	9.8	19.5	-	19.5	-	-	29.3
1997	17.2	12.8	30.0	34.5	4.2	38.7	.5	.9	70.1
1998	27.0	67.5	94.5	54.8	20.2	75.	2.4	1.8	173.7
1999	42.0	152.2	194.2	84.8	45.0	129.8	4.2	3.3	331.5
2000	57.0	257.1	314.1	114.8	75.6	190.4	6.1	5.4	516.0
2001	72.0	362.0	434.0	144.8	106.2	251.0	8.0	8.5	701.5
2002	87.0	466.6	553.6	174.8	136.6	311.4	10.0	11.5	886.5
2003	102.0	571.5	673.5	204.8	167.2	372.0	11.7	14.5	1,071.7
2004	117.0	676.4	793.4	234.8	197.8	432.6	13.6	17.6	1,257.2
2005	132.0	781.0	913.0	264.8	228.4	493.2	15.5	20.6	1,442.3

[1]One Bcf equals approximately 1.03 trillion Btu.

APPENDIX V

NGVs on the Road Due to Clean Air Act--Low Case
1995-2005
(Thousands)

	Fleet Cars	Light/ Medium Trucks	Heavy Duty Trucks	Urban Buses	Total
1995	4.5	15.0	-	-	19.5
1996	19.5	65.0	-	-	84.5
1997	42.0	118.5	.3	0.1	160.9
1998	90.0	200.0	1.4	0.1	291.5
1999	169.5	321.5	2.5	0.4	493.8
2000	253.5	448.0	3.6	0.5	705.5
2001	337.5	574.5	4.7	0.9	917.4
2002	421.5	701.0	5.8	1.1	1,129.2
2003	505.5	827.5	6.9	1.5	1,341.1
2004	589.5	954.0	8.0	1.8	1,552.9
2005	673.51	1,080.5	9.1	2.0	1,764.7

APPENDIX VI

NGVs on the Road Due to Clean Air Act--Base Case 1995-2005 (Thousands)

	Fleet Cars	Light/ Medium Trucks	Heavy Duty Trucks	Urban Buses	Total
1995	6	23	-	-	29
1996	26	98	-	-	124
1997	68	186	4	-	258
1998	186	338	8	1	533
1999	372	416	31	2	821
2000	588	812	44	3	1,447
2001	804	1,058	57	5	1,924
2002	1,019	1,304	70	6	2,399
2003	1,235	1,551	83	8	2,877
2004	1,451	1,797	97	10	3,355
2005	1,666	2,043	110	12	3,831

APPENDIX VII

NGVs on the Road Due to Clean Air Act--High Case
1995-2005
(Thousands)

	Fleet Cars	Light/ Medium Trucks	Heavy Duty Trucks	Urban Buses	Total
1995	9	26	-	-	35
1996	39	110	-	-	149
1997	120	219	8	1	348
1998	378	425	34	2	839
1999	777	735	59	4	1,575
2000	1,256	1,079	84	6	2,425
2001	1,736	1,422	109	9	3,276
2002	2,215	1,765	134	12	4,126
2003	2,694	2,108	160	15	4,977
2004	3,173	2,451	185	19	5,828
2005	3,652	2,795	210	22	6,679

APPENDIX VIII

Gas Demand from NGVs Attributable to Clean Air Act--High Case
1995-2005
(Bcf)

	Fleet Cars	Light/ Medium Trucks	Heavy Duty Trucks	Urban Buses	Total
1995	1.4	4.0	-	-	5.4
1996	5.8	16.5	-	-	22.3
1997	18.0	32.8	1.4	1.3	53.5
1998	56.7	63.8	5.8	2.5	128.8
1999	116.6	110.2	10.0	5.1	241.9
2000	188.4	161.8	14.3	7.6	372.1
001	260.4	213.3	18.5	11.4	503.6
2002	332.2	264.8	22.8	15.2	635.0
2003	404.1	316.2	27.2	19.0	766.5
2004	476.0	367.6	31.4	24.0	899.0
2005	547.8	419.2	35.7	27.8	1,030.5

APPENDIX IX

Gas Demand from NGVs Attributable to Clean Air Act--Base Case
1995-2005
(Bcf)

	Fleet Cars	Light/ Medium Trucks	Heavy Duty Trucks	Urban Buses	Total
1995	0.9	3.4	-	-	4.3
1996	3.9	14.7	-	-	18.6
1997	10.2	27.9	0.7	-	38.8
1998	27.9	50.7	1.4	1.3	81.3
1999	55.8	62.4	5.3	2.5	126.0
2000	88.2	121.8	7.5	3.8	221.3
2001	120.6	158.7	9.7	6.3	295.3
2002	152.9	195.6	11.9	7.6	368.0
2003	185.2	232.6	14.1	10.1	442.0
2004	217.6	270.0	16.5	12.6	516.7
2005	250.0	306.4	18.7	15.2	590.3

APPENDIX X

Gas Demand from NGVs Attributable to Clean Air Act--Low Case
1995-2005
(Bcf)

	Fleet Cars	Light/ Medium Trucks	Heavy Duty Trucks	Urban Buses	Total
1995	0.7	2.2	-	-	2.9
1996	2.9	9.8	-	-	12.7
1997	6.3	17.8	0.1	0.1	24.3
1998	13.5	30.0	0.2	0.1	43.8
1999	25.4	48.2	0.4	0.4	74.4
2000	38.0	67.2	0.6	0.5	106.3
2001	50.6	86.2	0.8	0.9	138.5
2002	63.2	105.2	1.0	1.1	170.5
2003	75.8	124.1	1.2	1.5	202.6
2004	88.4	143.1	1.4	1.8	234.7
2005	101.0	162.1	1.5	2.0	266.6

American Gas Association

Energy Analysis

1515 Wilson Boulevard
Arlington, Virginia 22209

A.G.A. Planning & Analysis Group

EA 1991-1

January 30, 1991

PROJECTED NATURAL GAS DEMAND FOR ACID RAIN CONTROL

A. Introduction

The Clean Air Act Amendments of 1990 are one of the most far-reaching environmental initiatives ever passed in this country. These amendments contain a number of sections germane to the natural gas industry, in particular, the acid rain, mobile source and ozone non-attainment provisions.

The purpose of the acid rain provisions is to reduce the emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from electricity generating plants by roughly 10 million and 2 million tons per year, respectively. The amendments do not specify how these reductions are to be achieved. Rather, plants affected are free to choose from a wide array of compliance options -- e.g., switching to natural gas or lower-sulfur coal, scrubbing, retiring plants or purchasing reductions achieved at some other unaffected plant.

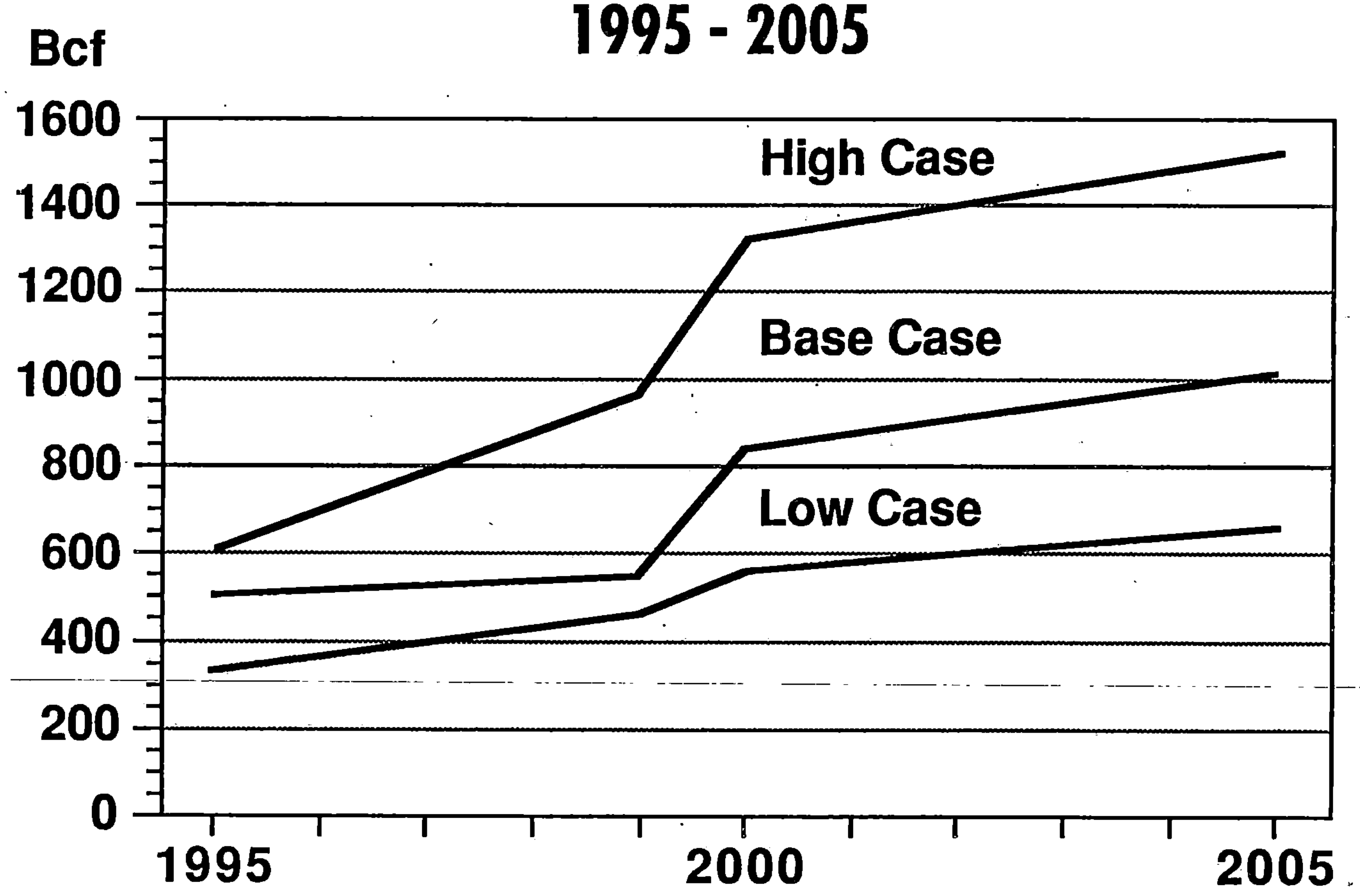
The purpose of this analysis is to estimate the incremental demand for natural gas attributable to the acid rain provisions of the amendments. A plant-by-plant analysis was completed for each of the 110 plants affected by Phase I. A more general analysis was conducted for Phase II, which takes effect in January 2000.

B. Executive Summary

This analysis projects that the incremental demand for natural gas attributable to the acid rain provisions will reach just over 1 trillion cubic feet per year by 2005 in the Base Case. High and Low Case estimates were also made, forming a range from 650 billion cubic feet to 1.5 trillion cubic feet in 2005 (see Exhibit 1). The Base Case results are summarized below.

Exhibit 1

INCREMENTAL GAS DEMAND FOR ACID RAIN CONTROL 1995 - 2005



Phase I

- 110 Plants -- The 110 large plants affected in Phase I (1995-2000) are projected to have a demand increase for natural gas of 510 billion cubic feet (Bcf) per year for acid rain compliance (see Exhibit 2).
    - This 510 Bcf is attributable to roughly one-fourth of the affected units, contributing about 11 percent of the total Phase I SO_2 reduction.
    - Scrubbers are expected to provide 50 to 60 percent of the Phase I reduction, and low sulfur coal some 30 to 40 percent.
    - Natural gas will be particularly attractive in older units and those with more modest reduction requirements, as well as those that would face difficulty in retrofitting scrubbers or changing coal sources.

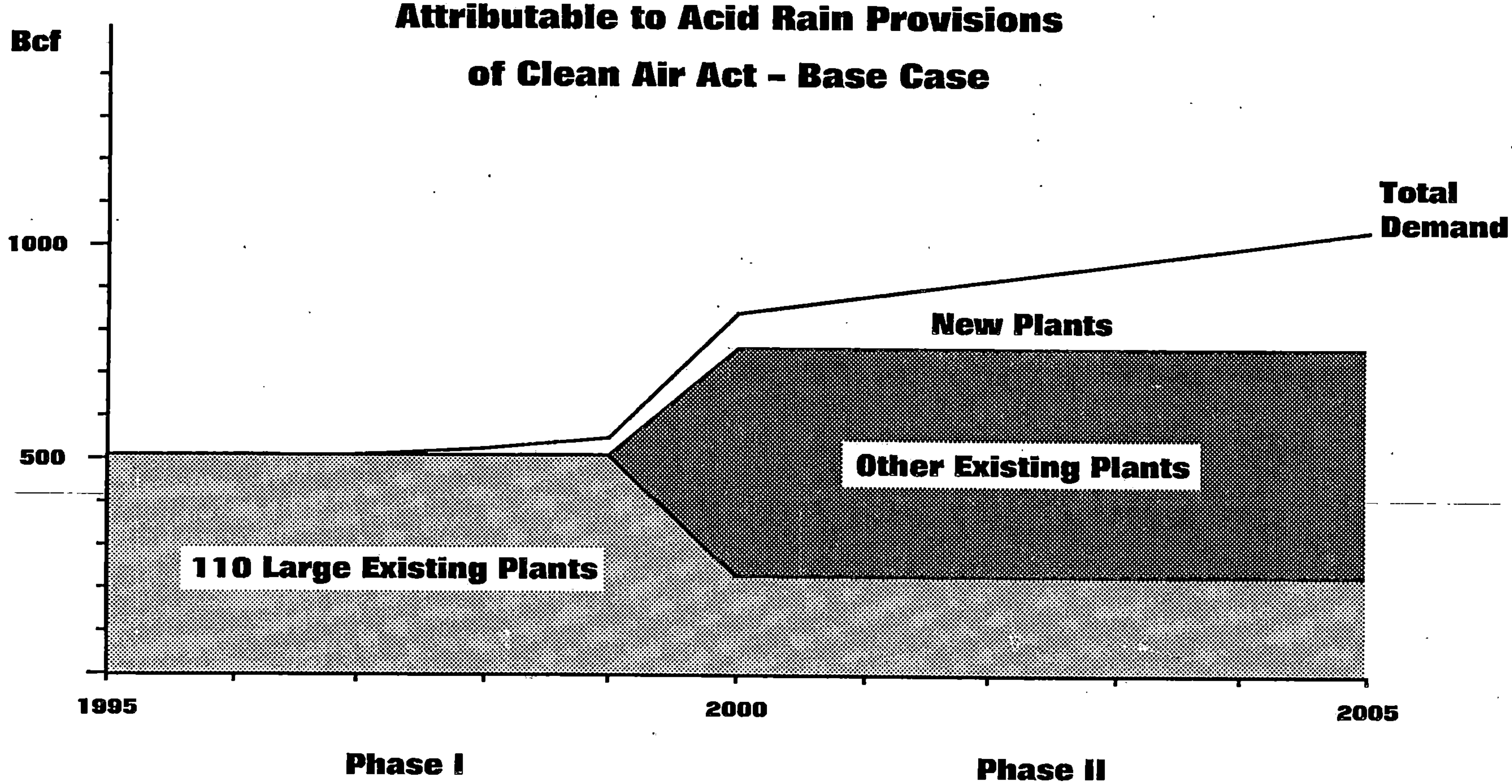
Phase II

The total Phase II demand increase for natural gas is estimated to reach 1,030 Bcf by 2005, just over double the Phase I level.

- 110 Plants -- The gas demand for the 110 large Phase I plants is projected to drop from 510 to 230 Bcf annually in Phase II, as the SO_2 reduction limit drops from 2.5 to 1.2 pounds per MMBtu.
- Other Existing Plants -- The gas focus will shift in Phase II to those coal and high-sulfur oil units emitting over 1.2 pounds of SO_2 per MMBtu. An annual demand of 530 Bcf is projected for these 400 or so plants, which tend to be smaller and/or cleaner than the 110 Phase I plants.
    - 470 Bcf is attributable to coal-fired plants not in the group of 110. Gas is projected to account for 20 percent of this group's required SO_2 reduction.
    - An additional 60 Bcf of gas demand is projected for high-sulfur oil units, which will satisfy 40 percent of the reduction mandate for these plants.
- New Plants -- New generating plants will turn increasingly to gas after the year 2000 because of the absolute SO_2 cap of 8.9 million tons. New coal or oil units brought on line after the cap is in place will have to obtain SO_2 offsets equivalent to their incremental SO_2 emissions. Gas units will not require offsets, and a demand increase of 270 Bcf per year by 2005 is projected for these plants.

Exhibit 2

Projected Incremental Natural Gas Demand Attributable to Acid Rain Provisions of Clean Air Act - Base Case



It should be noted that the gas used to comply with the acid rain provisions may or may not be consumed at the affected unit. An affected coal-fired electric power plant could substitute gas for coal on-site, or it could obtain its SO_2 reduction from some other plant on the electric utility system. In fact, because of the liberal trading provisions in the amendments, the reduction could even be acquired from an industrial source converting from high sulfur oil to gas and opting into the program.

C. Background

The general structure of the acid rain provisions of the Clean Air Act Amendments of 1990 is as follows. In Phase I -- January 1, 1995 until January 1, 2000 -- 110 electric utility generating units, each above 100 megawatts and emitting more than 2.5 pounds of SO_2 per MMBtu, must reduce their SO_2 emission rate to 2.5 pounds per MMBtu. In Phase II the program is expanded to include all units above 25 megawatts, and the emission rate limit is reduced to 1.2 pounds of SO_2 per MMBtu. In addition, after January 1, 2000, new electric utility plants and cogeneration units above 25 megawatts that come on line must not cause the total emissions of this sector to exceed an absolute cap of 8.9 million tons. Thus, if a new coal- or oil-fired plant will emit 25,000 tons of SO_2 per year, the plant owner is responsible for reducing emissions by 25,000 tons per year at some other site. The reduction could be obtained at some other plant on the same system, or it could be obtained at an unrelated electric utility or industrial plant and purchased by the responsible plant operator.

The most attractive features of the acid rain provisions from a natural gas industry perspective are that: (1) there is no restriction on how SO_2 reductions are achieved; (2) reduction allowances may be purchased, sold and traded; and (3) non-affected plants, both industrial and electric utility, may opt-in to the program. For example, a large industrial plant burning high-sulfur fuel oil in New York state could convert to natural gas and sell the reduction to an affected utility plant in some other state. This flexibility greatly enhances the value of natural gas, much of which is already consumed at dual-fuel capable facilities. It also provides affected plants with a significant source of SO_2 reductions which will be very competitive from an economic perspective. For example, most analysts would consider the addition of a scrubber that provides SO_2 reductions at a cost of \$250 per ton to be very economical. At this level of \$250 per ton of SO_2 removed, the incremental value of gas, when switching from 1.5 pounds per MMBtu fuel oil, is 20 cents per MMBtu, and, when switching from 5 pounds per MMBtu coal, the incremental value of gas is over 60 cents per MMBtu.

This trading possibility is often overlooked by analysts attempting to project the volumes of gas that will be required for acid rain control, and thus their projections tend to be low. In fact, the extremely flexible nature of the legislation makes it very difficult to determine exactly how electric utilities will comply. However, the outlook for natural gas is very favorable because: (1) natural gas emits virtually no

SO_2; (2) most gas is consumed at dual-fuel capable industrial and electric utility plants, which currently switch on the basis of swings of pennies per MMBtu, (3) an active trading market is anticipated with no geographic boundaries, and (4) the 8.9 million ton cap greatly enhances the value of gas as a fuel for new generating facilities, as well as an "offset" fuel in existing facilities to allow future growth.

D. Methodology

1. Phase I

An analysis of each of the 110 affected Phase I plants and its compliance options was performed. Most of the variables considered in this analysis are presented in Appendices A and B, and discussed below.

Identification. Each of the 110 affected plants, and the state in which it is located, is listed in column 1 of Appendix A. The affected generating units at the plants are listed in column 2 -- not all units at the 110 plants are affected.

Allowances. An allowance is essentially a permit to emit one ton of SO_2. The Phase I allowances, as provided in the legislation, are set out in column 3 of Appendix A.

Capacity. Column 4 of Appendix A indicates the size of the affected units in megawatts. Smaller units will be more likely to switch fuels for compliance -- to natural gas or low-sulfur coal -- due to the significant diseconomies of scale associated with scrubbing.

Age. The installation date of the affected units is provided in column 5 of Appendix A. Older units -- those built in the mid-1960s or earlier -- will be less likely candidates for the major engineering modifications required for scrubbers, and, to a lesser extent, changes in coal type.

Retrofit Potential. As indicated in column 6 of Appendix A, retrofitting scrubbers at existing plants can range from being relatively easy to virtually impossible. At some sites, scrubbers are precluded due to space limitations or other engineering factors. These sites are thus logical candidates to use natural gas or low-sulfur coal for compliance.

Boiler Type. Due to the differing combustion characteristics of high sulfur and low-sulfur coal, changing the coal feed of wet bottom or cyclone boilers is undesirable. These boiler types, indicated in column 7 of Appendix A, are more likely to use natural gas or scrubbers.

Gas Capability. The last column of Appendix A indicates whether the affected plant is on a utility system that includes gas-burning equipment -- steam or gas turbines. If the capacity of these units is large enough, additional gas could easily be substituted for higher-sulfur fuels in the fuel mix. Also, adding gas-burning capability on these systems would be easier, as some gas delivery capability already exists.

Coal Transport. Those plants supplied with coal via barge or rail would be more likely to shift to western low-sulfur coal than those supplied via conveyor or truck. The coal transport mode is indicated in column 3 of Appendix B.

Coal Source. Column 4 of Appendix B lists the state of origin of each plant's coal supply. Political or state regulatory pressure may limit the ability of plants using local high-sulfur coal to shift to out-of-state lower-sulfur coal, thus making gas co-firing and scrubbing more attractive.

Coal Contract. Mine-mouth generating stations or those receiving high-sulfur coal from company-owned mines or long-term contracts will be less likely to shift their coal source. These plants, indicated in column 5 of Appendix B, will be more likely to install scrubbers or use natural gas for compliance.

Fuel Input. The annual fuel input of the affected units is presented in column 6 of Appendix B. This estimate is based on the capacity of the unit, a 33 percent boiler efficiency and a 70 percent annual capacity utilization.

Emission Rate. Column 7 of Appendix B indicates the 1989 SO_2 emission rate of the affected units. In Phase I, this rate must be reduced to roughly 2.5 pounds per MMBtu. Units relatively close to this target will be more likely to use gas, while those far off will be less inclined to do so.

Gas Required. Columns 8 and 9 of Appendix B indicate the proportion of the fuel mix that would have to be natural gas, assuming the 1989 emission rate for the remainder of the mix, to meet the limits of 2.5 and 1.2 pounds per MMBtu of Phases I and II, respectively. It should be noted that this proportion could be lowered if gas were used in conjunction with some other strategy, such as additional coal cleaning or using a lower-sulfur, but non-compliance, coal.

The above factors, along with others not presented in the appendices, were considered in determining the likely compliance strategies of the 110 Phase I plants. For example, a small or moderately sized mine-mouth cyclone unit needing a 20 percent SO_2 reduction and having existing gas-fired boilers on the system would be a good candidate for gas substitution. A 1,200 megawatt unit burning 7 pounds-per-MMBtu coal with an easy scrubber retrofit factor would not.

One critical factor to consider is whether there is an easy or moderate difficulty scrubber retrofit on the system as opposed to the particular plant. Scrubbers at one large plant may provide excess allowances that could be used by smaller plants on the same system that can't scrub.

Results. The Phase I reduction requirement for the 110 plants is approximately 4.3 million tons of SO_2. This analysis indicates that using 510 Bcf of gas annually could satisfy the reduction requirements of about one-fourth of the affected units, contributing roughly 11 percent of the 110 plants' required SO_2 reduction -- 500,000 tons annually. The other 89 percent, or 3.8 million tons, would come from scrubbing or switching to low-sulfur coal. (It should be noted that when gas is substituted for oil, whether at the affected plant or via a trade, the quantity of gas required for the offset will be larger than if gas were substituted for coal, since oil-to-gas substitutions generally remove less SO_2 than coal-to-gas substitution.)

2. Phase II

In Phase II, affected plants will essentially be required to reduce their average emission rate to 1.2 pounds per MMBtu -- less than half the Phase I rate. This stringent cap would require a 70 to 80 percent gas substitution level for most of the 110 Phase I plants. Thus, it is projected that a smaller proportion of plants will use gas for compliance in Phase II, decreasing the gas used at these sites from 510 to 230 Bcf per year. The 10 years prior to the outset of Phase II will be used to install scrubbers at a more manageable pace, and to allow old coal contracts to terminate so that newer contracts for lower-sulfur coals can be executed.

The gas focus in Phase II will shift from the 110 largest plants to roughly 400 smaller existing plants that will also be affected. Coal plants (outside of the 110) will be required to emit no more than 1.2 pounds per MMBtu, resulting in an emission reduction of some 1.5 to 2.0 million tons of SO_2 per year. An analysis as detailed as that done for the 110 plants was not performed on these smaller plants. Rather, it was assumed that the share of the tonnage reduction provided by gas would increase from 11 percent in Phase I to roughly 20 percent in Phase II for these smaller and/or cleaner units. These units are more attractive gas candidates because they are smaller, will require a lesser percentage reduction than most Phase I plants, and scrubbing them would be far more costly. Scrubbers are expected to produce 50 to 60 percent of the Phase I 110-plant reduction, but only about 10 percent of the reduction from the smaller Phase II coal units. In contrast, the low-sulfur coal share is anticipated to increase from about 30 or 40 percent to roughly 70 percent.

Of the 360,000-ton SO_2 reduction projected attributable to gas for the smaller coal plants, 80 percent is projected to result from oil-to-gas substitution and 20 percent from coal-to-gas substitution. Again, this gas substitution for the higher-sulfur fuels could take place at the affected units or at other units that subsequently transfer them to the affected units. The annual gas demand at these plants is projected at 470 Bcf.

High-sulfur oil plants will also be affected in Phase II. About 1,600 trillion Btu of oil is currently consumed by electric utilities annually, and about one-fourth of this oil exceeds the 1.2 pound per MMBtu Phase II limit. A total SO_2 reduction of some 160,000 tons per year will be required of these plants -- 40 percent of which is assumed to be satisfied with gas, the remainder by switching to lower-sulfur oil. These plants, many of which already have both gas- and oil-burning capability, are projected to demand an additional 60 Bcf per year for acid rain compliance.

The final category of plants that will demand additional gas for acid rain compliance in Phase II is new electricity generating units -- including both cogenerators and electric utility plants. There is an absolute cap of 8.9 million tons of SO_2 per year for generating plants in 2000 and beyond. Generating units that come on line post-2000 and that produce SO_2 must reduce an equivalent amount of SO_2 at some other site. Thus, there will be a strong preference for gas to fuel these units, since gas emits no SO_2.

It is estimated that an additional 5 percent of the utility and non-utility (cogenerators and independent power producers) units will be gas-fired as a result of the legislation. (Most analysts projected that the market share for gas would be very high in these markets -- 35 to 70 percent -- even without the clean air legislation.) This translates into an additional 270 Bcf per year by 2005, based on projected capacity additions of 5,000 megawatts per year for cogenerators and 10,000 megawatts per year for utility plants.

In aggregate, the total incremental gas demand in 2005 from the 110 Phase I plants, the smaller Phase II coal and oil plants, and the new generating units is projected to be 1,030 Bcf per year.

3. High and Low Case Assumptions

Natural gas provides 11 percent of the required SO_2 reduction in Phase I. This increases to 13 percent in the High Case, and reduces to 7.5 percent in the Low Case, resulting in a Phase I range of 350 to 600 Bcf per year.

The Phase II decline in gas demand at the 110 plants is 25 percent more severe in the Low Case and 50 percent less severe in the High Case. Whereas gas satisfies 20 percent of the required SO_2 reduction in the Base Case for small coal-fired units in Phase II, it satisfies 10 and 30 percent in the Low and High Cases, respectively. Similarly, the 40 percent contribution of gas in small oil-fired units is reduced to 20 percent in the Low Case and increased to 50 percent in the High Case. The incremental 5 percent market share in the electricity generation market in Phase II is reduced to 4 percent in the Low Case and increased to 7 percent in the High Case. The range in the year 2005 as a result of these modifications is 650 to 1,500 Bcf per year.

Characteristics of Affected Phase I Electric Utility Power Plants -- A

State Plant[1]	Unit[1]	Phase I Allowances (Tons/Yr)[1]	Capacity (Summer, Megawatts[2])	Installation Date[2]	Scrubber Retrofit Potential[2]	Boiler Type[2]	Gas-Burning Capability On System[3]
Alabama							
Colbert	1-4	59,690	776	1955	VD	-	GT
	5	37,180	496	1965	E	-	GT
EC Gaston	1-4	74,230	1,044	1960-62	VD	-	ST
	5	59,840	887	1974	D	-	ST
Florida							
Big Bend	1-3	82,250	1,079	1970-76	M	W	-
Crist	6-7	50,880	809	1970-73	M	-	ST
Georgia							
Bowen	1-4	254,580	3,009	1971-75	E	-	ST,GT
Hammond	1-3	26,910	300	1954-55	D	-	ST,GT
	4	37,640	459	1970	M	-	ST,GT
McDonough	1-2	40,510	507	1964	D	-	ST,GT
Wansley	1-2	136,200	1,747	1976-78	E	-	ST,GT
Yates	1-5	39,520	574	1950-58	D	-	ST,GT
	6-7	46,240	682	1974	E	-	ST,GT
Illinois							
Baldwin	1-3	128,980	1,761	1970-75	M	C	ST,GT
Coffeen	1-2	47,460	840	1965-72	E	C	GT
Grand Tower	4	5,910	103	1958	VD	-	GT
Hennepin	2	18,410	224	1957	D	-	ST,GT
Joppa Steam	1-6	69,030	1,014	1953-55	M	-	-
Kincaid	1-2	65,340	1,108	1967-68	M	C	ST,GT
Meredosia	3	13,890	180	1960	VD	-	GT
Vermilion	2	8,880	107	1956	D	-	ST,GT
Indiana							
Bailly	7-8	26,810	490	1962-68	D	C	ST,GT
Breed	1	18,500	380	1960	E	NA	-
Cayuga	1-2	67,500	985	1970-72	M	-	-
Clifty Creek	1-6	100,830	1,215	1955-56	D	W	-
EW Stout	5-6	28,010	212	1958-61	VD	-	-
	7	23,610	439	1973	E	-	-
FB Culley	2-3	21,260	351	1966-73	VD	-	GT
FE Ratts	1-2	16,810	230	1968	M	-	-

State Plant[1]	Unit[1]	Phase Allowances (Tons/Yr)[1]	Capacity (Summer, Megawatts[2])	Installation Date[2]	Scrubber Retrofit Potential[2]	Boiler Type[2]	Gas-Burning Capability On System[3]
Indiana							
Gibson	1-4	162,810	2,540	1975-79	E	-	-
Pritchard	6	5,770	99	1956	NA	NA	-
Michigan City	12	23,310	468	1974	D	C	ST,GT
Petersburg	1-2	48,810	700	1967-69	M	-	-
Gallagher	1-4	27,950	560	1958-61	D	-	-
Tanners Creek	4	24,820	500	1964	D	C	-
Wabash River	1-5	14,280	435	1953-56	VD	-	-
	6	12,280	318	1958	D	-	-
Warrick	4	26,980	300	1970	D	-	GT
Iowa							
Burlington	1	10,710	207	1968	NA	NA	-
Des Moines	7	2,320	119	1964	NA	NA	ST,GT
George Neal	1	1,290	130	1964	NA	NA	ST,GT
ML Kapp	2	13,800	217	1967	D	-	ST
Prairie Creek	4	8,180	139	1967	NA	NA	ST
Riverside	5	3,990	130	1961	NA	NA	ST,GT
Kansas							
Quindaro	2	4,220	145	1971	D	C	ST
Kentucky							
Coleman	1-3	36,430	450	1969-71	M	-	-
Cooper	1-2	22,770	336	1965-69	VD	-	-
EW Brown	1-2	18,020	271	1957-63	VD	-	GT
	3	26,100	394	1971	M	-	GT
Elmer Smith	1-2	20,930	399	1964-74	VD	C	-
Ghent	1	28,410	522	1974	D	-	GT
Green River	4	7,820	109	1959	NA	NA	GT
HL Spurlock	1	22,780	300	1977	NA	NA	-
Henderson II	1-2	25,650	300	1973	D	W	-
Paradise	3	59,170	1,046	1970	E	C	GT
Shawnee	10	10,170	147	1953	NA	NA	GT
Maryland							
Chalk Point	1-2	46,240	660	1964-65	M	-	ST
CP Crane	1-2	19,560	376	1961-62	NA	NA	ST,GT
Morgantown	1-2	73,740	1,163	1970-71	E	-	ST

State Plant[1]	Unit[1]	Phase Allowances (Tons/Yr)[1]	Capacity (Summer, Megawatts[2])	Installation Date[2]	Scrubber Retrofit Potential[2]	Boiler Type[2]	Gas-Burning Capability On System[3]
Michigan							
JH Cambell	1-2	42,340	583	1962-67	M	-	GT
Minnesota							
High Bridge	6	4,270	179	1959	NA	NA	ST,GT
Mississippi							
Jack Watson	4	17,910	260	1968	D	-	ST,GT
	5	36,700	502	1973	E	-	ST,GT
Missouri							
Asbury	1	16,190	200	1970	M	C	-
James River	5	4,850	90	1970	NA	NA	ST,GT
Labadie	1-4	154,070	2,216	1970-73	D	-	ST,GT
Montrose	1-3	25,680	450	1958-64	VD	-	ST
New Madrid	1-2	60,720	1,200	1972-77	M	C	-
Sibley	3	15,580	353	1969	M	C	GT
Sioux	1-2	46,260	900	1967-68	M	C	ST,GT
Thomas Hill	1-2	29,640	483	1965-69	M	C	-
New Hampshire							
Merrimack	1-2	32,190	357	1960-68	D	C	GT
New Jersey							
BL England	1-2	20,780	289	1962-64	VD	C	ST,GT
New York							
Dunkirk	3-4	26,660	375	1959-60	VD	-	ST,GT
Greenidge	4	7,540	104	1953	VD	-	-
Milliken	1-2	23,580	308	1955-58	VD	-	-
Northport	1-3	70,400	1,137	1958-60	NA	NA	ST,GT
Port Jefferson	3-4	22,800	388	1968-72	NA	NA	ST,GT
Ohio							
Ashtabula	5	16,740	243	1958	VD	-	-
Avon Lake	8	11,650	230	1959	VD	-	-
	9	30,480	634	1970	D	-	-
Cardinal	1-2	72,590	1,170	1967-68	D	C	-
Conesville	1-3	14,600	391	1959-62	VD	C	-
	4	48,770	733	1973	E	C	-
Eastlake	1-4	40,970	637	1953-56	VD	-	-
	5	34,070	445	1972	D	-	-

State Plant[1]	Unit[1]	Phase I Allowances (Tons/Yr)[1]	Capacity (Summer, Megawatts[2])	Installation Date[2]	Scrubber Retrofit Potential[2]	Boiler Type[2]	Gas-Burning Capability On System[3]
Ohio							
Edgewater	4	5,050	103	1957	NA	NA	-
JM Gavin	1-2	159,640	2,600	1974-75	E	-	-
Kyger Creek	1-5	93,200	1,019	1955	M	W	-
Miami Fort	5-6	12,140	243	1949-60	D	-	GT
	7	38,510	500	1975	M	-	GT
Muskingum River	1-4	54,780	790	1953-58	D	C	-
	5	40,470	575	1968	E	C	-
Niles	1-2	16,040	228	1954	VD	C	-
Picway	5	4,930	95	1955	NA	NA	-
RE Burger	3-5	29,360	402	1950-55	D	-	-
WH Sammis	5-6	64,100	900	1967-69	VD	-	-
	7	43,220	600	1971	D	-	-
WC Beckjord	5-6	31,970	653	1962-69	D	-	GT
Pennsylvania							
Armstrong	1-2	29,840	349	1958-59	VD	-	-
Brunner Island	1-2	58,860	699	1961-65	M	-	-
	3	53,820	730	1969	E	-	-
Cheswick	1	39,170	562	1970	M	-	ST
Conemaugh	1-2	126,240	1,702	1970-71	E	-	GT
Hatfields Ferry	1-3	115,420	1,500	1969-71	E	-	-
Martins Creek	1-2	25,480	280	1954-56	NA	NA	-
Portland	1-2	16,170	401	1958-62	D	-	GT
Shawville	1-4	48,930	606	1954-60	VD	-	GT
Sunbury	3-4	20,210	222	1951-53	VD	-	-
Tennessee							
Allen	1-3	47,760	873	1965	D	C	GT
Cumberland	1-2	181,540	2,550	1973	E	-	GT
Gallatin	1-4	76,460	1,080	1956-59	D	-	GT
Johnsonville	1-10	80,670	1,304	1951-59	VD	-	GT
West Virginia							
Albright	3	12,000	137	1954	VD	-	-
Fort Martin	1-2	82,790	1,110	1967-68	D	-	-
Harrison	1-3	136,270	1,920	1972-74	M	-	-
Kammer	1-3	55,590	600	1958-59	VD	C	-
Mitchell	1-2	89,490	1,460	1971	VD	-	-

State Plant[1]	Unit[1]	Phase I Allowances (Tons/Yr)[1]	Capacity (Summer, Megawatts[2])	Installation Date[2]	Scrubber Retrofit Potential[2]	Boiler Type[2]	Gas-Burning Capability On System[3]
Mount Storm	1-3	121,730	1,574	1965-73	E	-	-
Wisconsin							
Edgewater	4	24,750	334	1969	VD	C	ST,GT
La Crosse/Genoa	3	22,700	345	1969	VD	-	-
Nelson Dewey	1-2	12,690	211	1959-62	D	C	ST,GT
N. Oak Creek	1-4	22,050	430	1953-57	VD	-	GT
Pulliam	8	7,510	123	1964	D	-	ST,GT
S. Oak Creek	5-8	53,680	1,057	1960-68	VD	-	GT

Abbreviations:

NA - Data not available
E - Easy scrubber retrofit, 1.0 to 1.3 times capital cost of FGD at new 500 MW unit.
M - Moderate scrubber retrofit, 1.3 to 1.6 times capital cost of FGD at new 500 MW unit.
D - Difficult scrubber retrofit, 1.6 to 1.9 times capital cost of FGD at new 500 MW unit.
VD - Very difficult scrubber retrofit, more than 1.9 times capital cost of FGD at new 500 MW unit.
C - Cyclone
W - Wet bottom
ST - Steam boiler
GT - Gas turbine

Sources:

[1] U.S. House of Representatives, Clean Air Act Amendments of 1990, Conference Report to accompany S.1630, (Washington, DC: U.S. GPO, October 26, 1990) pp. 208-213.

[2] Energy Ventures Analysis, Inc., for the U.S. Environmental Protection Agency, Evaluation of SO_2, Emissions and the FGD Retrofit Feasibility at the 200 Top Emitting Generating Stations, (Washington, DC: January 10, 1986).

[3] U.S. Department of Energy, Energy Information Administration, Inventory of Power Plants in the United States -- 1989, (Washington, DC: U.S. GPO, September 1990).

Characteristics of Affected Phase I Electric Utility Power Plants -- B

State Plant[1]	Unit[1]	Coal Supply[2] Transport Mode	Origin	Favorable Contract	Fuel Input (TBtu/yr)[3]	1989 Emission Rate (#SO_2/MMBtu)[4]	Percent Gas Required[5] Phase I	Phase II
Alabama								
Colbert	1-4	B	OH	-	48	3.89	36	69
	5	B	OH	-	31	3.89	36	69
EC Gaston	1-4	C,R	AL	X	65	3.32	25	64
	5	C,R	AL	X	55	3.32	25	64
Florida								
Big Bend	1-3	B	WKY	-	67	3.55	30	67
Crist	6-7	B	IL,WKY	-	50	4.63	46	74
Georgia								
Bowen	1-4	R	EKY,WKY	X	188	2.29	-	48
Hammond	1-3	R	EKY,VA	-	18	2.91	14	59
	4	R	EKY,VA	-	28	2.91	14	59
McDonough	1-2	R	IL,WKY	-	31	4.34	42	72
Wansley	1-2	R	IL,IN	-	109	4.43	44	73
Yates	1-5	R	IL,AL	-	36	3.61	31	67
	6-7	R	IL,AL	-	42	3.61	31	67
Illinois								
Baldwin	1-3	R	IL	X	110	5.31	53	78
Coffen	1-2	R	IL	X	52	6.88	64	83
Grand Tower	4	R	IL	-	6	5.11	51	77
Hennepin	2	B	IL	X	14	5.26	52	78
Joppa Steam	1-6	R,B	IL,WKY	-	63	3.35	25	64
Kincaid	1-2	C	IL	X	69	6.74	63	83
Meredosia	3	B,T	IL	-	11	4.53	45	74
Vermilion	2	T	IL,IN	-	7	4.20	40	71
Indiana								
Bailly	7-8	R	IL	X	30	4.85	48	75
Breed	1	NA	NA	NA	23	7.11	65	83
Cayuga	1-2	R	IN	-	61	4.04	38	70
Clifty Creek	1-6	B	WKY,IN	-	76	5.95	58	80
EW Stout	5-6	R	IN	-	13	3.26	23	63
	7	R	IN	-	27	3.26	23	63
FB Culley	2-3	T	IN	-	22	5.46	54	78

State Plant[1]	Unit[1]	Coal Supply[2] Transport Mode	Origin	Favorable Contract	Fuel Input (TBtu/yr)[3]	1989 Emission Rate ($\#SO_2$/MMBtu)[4]	Percent Gas Required[5] Phase I	Phase II
FE Ratts	1-2	T	IN	-	14	5.27	53	77
Gibson	1-4	R	IL,IN	X	159	4.48	44	73
Pritchard	6	NA	NA	NA	6	3.50	29	66
Michigan City	12	R	IL	-	29	4.14	40	71
Petersburg	1-2	R,T	IN	X	44	4.16	40	71
Gallagher	1-4	B	IN	-	35	4.24	41	72
Tanners Creek	4	B	WKY,NWV	-	31	3.08	19	61
Wabash River	1-5	R	IN	-	27	3.88	36	69
	6	R	IN	-	19	3.88	36	69
Warrick	4	R	IN	X	18	5.71	56	79
Iowa								
Burlington	1	NA	IL,IN,KY	NA	13	4.94	49	76
Des Moines	7	NA	NA	NA	7	NA	NA	NA
George Neal	1	NA	WY	NA	8	.95	-	-
ML Kapp	2	B	IL,MT	-	13	5.25	52	77
Prairie Creek	4	NA	IL,IN	NA	8	4.57	45	74
Riverside	5	NA	IL	NA	8	3.35	25	64
Kansas								
Quindaro	2	R	IL	-	9	2.58	3	53
Kentucky								
Coleman	1-3	B	IN,WKY	-	28	4.26	41	72
Cooper	1-2	T,R	EKY	-	21	2.40	-	50
EW Brown	1-2	R,T	EKY,TN	-	17	3.55	30	66
	3	R,T	EKY,TN	-	24	3.55	30	66
Elmer Smith	1-2	T	WKY,IN	-	25	5.37	53	78
Ghent	1	B	IN,EKY	X	32	2.58	3	53
Green River	4	NA	NA	NA	6	3.86	35	69
HL Spurlock	1	NA	NA	NA	18	1.78	-	33
Henderson II	1-2	B	IN,WKY	-	18	NA	NA	NA
Paradise	3	C,B,T	WKY	X	65	8.36	70	86
Shawnee	10	NA	NA	NA	9	1.92	-	37
Maryland								
Chalk Point	1-2	R	PA,MD	-	41	2.85	9	-

State Plant[1]	Unit[1]	Coal Supply[2] Transport Mode	Coal Supply[2] Origin	Coal Supply[2] Favorable Contract	Fuel Input (TBtu/yr)[3]	1989 Emission Rate (#SO_2/MMBtu)[4]	Percent Gas Required[5] Phase I	Percent Gas Required[5] Phase II
Maryland								
CP Crane	1-2	NA	NA	NA	23	3.14	20	62
Morgantown	1-2	R	PA,MD	-	72	2.90	14	59
Michigan								
JH Cambell	1-2	R,B	OH,EKY	-	36	1.18	-	-
Minnesota								
High Bridge	6	NA	NA	NA	11	.57	-	-
Mississippi								
Jack Watson	4	B	AL,WKY	-	16	3.87	35	69
	5	B	AL,WKY	-	31	3.87	35	69
Missouri								
Asbury	1	C	MO,KS	X	13	9.32	73	87
James River	5	NA	NA	NA	6	4.11	39	71
Labadie	1-4	R	IL	X	139	4.53	45	74
Montrose	1-3	T,R	MO,OK	X	28	.83	-	-
New Madrid	1-2	B	IL	-	75	5.77	57	79
Sibley	3	R	IL	-	22	5.60	55	79
Sioux	1-2	R	IL,WY	X	56	3.24	23	63
Thomas Hill	1-2	T	MO,IL	X	30	7.77	68	85
New Hampshire								
Merrimack	1-2	R	NWV	-	22	3.05	18	60
New Jersey								
BL England	1-2	R	NWV	-	18	3.87	35	70
New York								
Dunkirk	3-4	R,T	PA	-	23	3.19	22	62
Greenidge	4	R,T	PA	-	6	3.11	20	61
Milliken	1-2	R,T	PA	-	19	2.76	9	57
Northport	1-3	WA	NA	NA	71	1.0	-	-
Port Jefferson	3-4	WA	NA	NA	24	1.0	-	-
Ohio								
Ashtabula	5	R	OH,PA	-	15	4.97	50	76
Avon Lake	8	R	OH	-	14	3.86	35	69
	9	R	OH	-	39	3.86	35	69
Cardinal	1-2	B,R,T	OH,SWV	X	73	3.79	34	68

State Plant[1]	Unit[1]	Coal Supply[2] Transport Mode	Origin	Favorable Contract	Fuel Input (TBtu/yr)[3]	1989 Emission Rate (#SO_2/MMBtu)[4]	Percent Gas Required[5] Phase I	Phase II
Ohio								
Conesville	1-3	C,T	OH	X	24	5.34	53	78
	4	C,T	OH	X	46	5.34	53	78
Eastlake	1-4	R	OH	-	39	4.88	49	75
	5	R	OH	-	27	4.88	49	75
Edgewater	4	NA	NA	NA	6	3.84	35	69
JM Gavin	1-2	C,R,B	OH	X	163	5.74	56	79
Kyger Creek	1-5	B	NWV,OH	-	63	6.36	61	81
Miami Fort	5-6	B	SWV,OH	-	15	2.84	12	58
	7	B	SWV,OH	-	31	2.84	12	58
Muskingum River	1-4	C	OH	X	49	7.67	67	84
	5	C	OH	X	36	7.67	67	84
Niles	1-2	T	OH,PA	-	14	5.42	54	78
Picway	5	NA	NA	NA	6	4.99	50	76
RE Burger	3-5	B	OH	-	25	4.97	50	76
WH Sammis	5-6	B	OH,PA	-	56	2.85	12	58
	7	B	OH,PA	-	37	2.85	12	58
WC Beckjord	5-6	B	OH,EKY	-	40	2.94	15	59
Pennsylvania								
Armstrong	1-2	T	PA	-	21	2.97	16	60
Brunner Island	1-2	R	PA	X	43	2.78	10	57
	3	R	PA	X	45	2.78	10	57
Cheswick	1	B	PA	X	35	2.50	-	52
Conemaugh	1-2	C,T,R	PA	X	106	3.35	25	64
Hatfields Ferry	1-3	B	NWV,PA	X	94	3.31	24	64
Martins Creek	1-2	NA	NA	NA	17	3.14	20	62
Portland	1-2	R	PA,NWV	-	25	2.82	11	57
Shawville	1-4	T	PA	-	38	3.19	22	62
Sunburey	3-4	R,T	PA	-	13	3.65	32	67
Tennessee								
Allen	1-3	B	WKY	-	54	3.59	30	67
Cumberland	1-2	B	WKY	X	160	4.80	48	75
Gallatin	1-4	B,R	WKY	-	67	4.56	45	74
Johnsonville	1-10	B	IN,WKY	-	81	2.94	15	59

State Plant[1]	Unit[1]	Coal Supply[2] Transport Mode	Origin	Favorable Contract	Fuel Input (TBtu/yr)[3]	1989 Emission Rate (#SO_2/MMBtu)[4]	Percent Gas Required[5] Phase I	Phase II
West Virginia								
Albright	3	T	NWV	-	9	2.61	4	54
Fort Martin	1-2	B	NWV,EKY	-	69	2.81	11	57
Harrison	1-3	C,R,T	NWV	X	120	4.66	46	74
Kammer	1-3	C	NWV	X	37	6.89	64	83
Mitchell	1-2	R,B	NWV	X	91	2.06	-	42
Mount Storm	1-3	C,R,T	NWV	X	98	2.91	14	59
Wisconsin								
Edgewater	4	R	IL,IN	-	20	2.50	-	52
La Crosse/Genoa	3	B	IL,MT	-	21	3.78	34	68
Nelson Dewey	1-2	B	IL,IN	-	13	1.57	-	24
N. Oak Creek	1-4	R,B	WKY,IL	-	26	2.64	5	55
Pulliam	8	B	WKY,IN	-	8	3.54	29	66
S. Oak Creek	5-8	R,B	WKY,IL	-	66	2.64	5	55

Abbreviations:
- NA - Data not available
- B - Barge
- R - Rail
- T - Truck
- C - Conveyor

Sources:

[1] U.S. House of Representatives, Clean Air Act of 1990, Conference Report to accompany S.1630, (Washington, DC: U.S. GPO, October 26, 1990) pp. 208-213.

[2] Energy Ventures Analysis, Inc. for the U.S. Environmental Protection Agency, Evaluation of SO_2 Emissions and the FGD Retrofit Feasibility at the 200 Top Emitting Generating Stations, (Washington, DC: January 10, 1986).

[3] Calculated on the basis of 70 percent annual capacity utilization and 33 percent boiler efficiency.

[4] National Coal Association, Steam Electric Plant Factors - 1990, (Washington, DC: 1990).

[5] Calculated on the basis of percent of gas required in fuel mix to reduce SO_2 emission rate to 2.5 #/MMBtu in Phase I and 1.2 #/MMBtu in Phase II.