Interstate Natural Gas Association of America

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November 25, 2008

Air and Radiation Docket and Information Center
Environmental Protection Agency
Mail Code 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Docket No. EPA-HQ-OAR-2008-0318

Dear Sir or Madam:

The Interstate Natural Gas Association of America (INGAA), a trade association of the interstate natural gas pipeline industry, submits these comments on the Environmental Protection Agency's Advanced Notice of Proposed Rulemaking regulating greenhouse gases under the Clean Air Act (CAA) and response to Massachusetts v. EPA.

INGAA member companies transport more than 90 percent of the nation's natural gas, through some 200,000 miles of interstate natural gas pipelines. Our industry operates more than 5,800 natural gas-fired reciprocating internal combustion engines and 1,000 natural gas-fired combustion turbines at compressor stations and natural gas storage facilities across the United States. In addition to its economic importance, natural gas represents the cleanest burning fossil fuel, with lower emissions of greenhouse gases (GHGs), criteria pollutants, and hazardous air pollutants as compared to other primary domestic energy resources. The U.S. will increasingly rely upon natural gas supply and distribution to meet our electricity generation demands and environmental goals.

Natural gas pipeline operations are essential to providing new and existing power plants with this clean-burning fuel. Additionally, a robust natural gas distribution network will facilitate the service of newer, more efficient and flexible "distributed generation" systems that are capable of converting natural gas to useful energy products at the highest efficiency of any fossil fuel.

We appreciate EPA's consideration of these comments, and offer our assistance in the ongoing discussion of the potential regulation of GHGs and mitigating the effects of climate change. If you have any questions, please contact me at 202-216-5935.

Sincerely,

Lisa S Beal

Lisa Beal
Director, Environment and Construction Policy
Interstate Natural Gas Association of America

Attachment: Comments Of The Interstate Natural Gas Association Of America to the U.S. Environmental Protection Agency Advance Notice of Proposed Rulemaking (ANPR) published in the *Federal Register* on July 30, 2008 (73 Fed. Reg. 44353)

UNITED STATES OF AMERICA
BEFORE THE
ENVIRONMENTAL PROTECTION AGENCY

Regulating Greenhouse Gas Emissions under the Clean Air Act	))	Docket No. EPA-HQ-OAR-2008-0318
	)	FRL-8694-2
Advance Notice of Public Rulemaking	))	RIN 2060-AP12

COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Pursuant to the Advance Notice of Proposed Rulemaking (ANPR) issued by the Environmental Protection Agency (EPA) on July 11, 2008, and published in the *Federal Register* on July 30, 2008,[1] the Interstate Natural Gas Association of America (INGAA) comments as follows:

EXECUTIVE SUMMARY

On behalf of the nation's interstate natural gas transmission pipelines,[2] INGAA welcomes this opportunity to comment on the ANPR. INGAA encourages the development of an effective and well designed federal response to global warming. At the same time, INGAA agrees that the Clean Air Act (CAA) is ill-suited for regulating greenhouse gases (GHGs). We join the voices of many others — within EPA, from other federal agencies and throughout the private sector — supporting climate change legislation in lieu of trying to regulate GHGs under the CAA.

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1 *Regulating Greenhouse Gas Emissions Under the Clean Air Act*, 73 Fed. Reg. 44353.

2 INGAA is a non-profit trade association representing virtually all of the interstate natural gas transmission pipeline companies operating in the United States and the interprovincial pipelines operating in Canada. INGAA's U.S. members operate over 200,000 miles of pipeline and related facilities and account for over 90% of all natural gas transported and sold in interstate commerce.

INGAA views the ANPR as an invitation to address the broader aspects of regulating GHG emissions, and we offer principles that should be part of any mandatory federal program. We also explain the unique role to be played by natural gas, the bridge fuel to a less carbon-intensive U.S. economy.

INGAA appreciates EPA's effort to address *Massachusetts v. EPA.*[3] We urge EPA to do so with utmost circumspection, being appropriately thorough and complete given the magnitude of the environmental and economic issues involved.[4] Careful study is particularly critical on matters concerning endangerment, since a single conclusion here may very well trigger the mandatory imposition of an array of regulatory programs within the CAA.

INGAA members believe that a full appreciation for the role natural gas will play in achieving net reductions in emissions would preclude any policies that impede the production, processing or transportation of this clean-burning, domestically available energy source. Nevertheless, since cap-and-trade programs are mentioned in the ANPR, we provide some general criteria for designing the most useful appropriate approach to covering the natural gas industry. In particular, we detail why interstate transmission pipelines are not the appropriate point of regulation for a GHG cap-and-trade program.

Finally, we look at the various CAA regulatory programs and explain how applying them to GHGs would impose significant, possibly insurmountable challenges. Program by program, INGAA examines the burdens and costs to its members, to the broader affected public and to the

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3 549 U.S. 497 (2007).

4 A recent study estimates that if EPA regulates GHGs under the CAA, U.S. Gross Domestic Product (GDP) will fall by over $600 billion by 2029, with an aggregate income loss of over $6.8 trillion over a 20 year period. Co2-Emission Cuts: The Economic Costs Of The EPA' S ANPR Regulations, David W. Kreutzer, Ph.D., and Karen A. Campbell, Ph.D. (The Heritage Center for Data Analysis (Cda08-10) October 29, 2008).

agencies that would be responsible for reviewing applications, issuing permits and handling other aspects of program administration. We conclude:

- ✦ Regulation under CAA Section 111 would impose inordinate costs on the natural gas transmission industry, without commensurate benefit, because of the number of sources that would become subject to New Source Performance Standards (NSPS) and permitting. Although the ANPR suggests establishing a cap-and-trade program in lieu of Section 111 regulation (and other CAA regulatory programs), we are concerned EPA may not have legal authority to do so.
- ✦ Because of the statutorily-set emissions thresholds governing New Source Review (NSR) and Prevention of Significant Deterioration (PSD) permitting, imposing these programs would threaten natural gas transmission system reliability, and perhaps even safety, to the extent maintenance, repairs and similar activities would have to be deferred while operators wait for the necessary permits.
- ✦ The challenges posed by regulating GHGs under the Hazardous Air Pollutant (HAP) program or CAA Title V are even greater. HAP regulation would impose inordinate if not crippling costs on the general public and INGAA members, both because of the extremely low (and statutorily-set) emissions thresholds and because of the statutory requirement to impose the maximum available control technology regardless of cost. For both HAP regulation and regulation under Title V, the number of required administrative activities (standard setting, application review, permit issuance, the examination of petitions for delisting and other exemptions, *etc*.) would overwhelm the existing regulatory system.

COMMENTS

I. INTRODUCTION AND GENERAL INGAA OVERVIEW

INGAA welcomes the opportunity to comment on the ANPR as part of a larger debate on mitigating the effects of climate change. We agree with the EPA Administrator Johnson that the CAA "is ill-suited for the task of regulating global greenhouse gases."[5] Instead, we support a mandatory federal climate change program — enacted by the Congress — that would address global warming in the most effective manner possible, constructively engage climate change efforts at the international level, and preempt redundant and potentially conflicting state or regional initiatives.

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5 ANPR, 73 Fed. Reg. at 44355.

INGAA's comments address the role natural gas should play in climate change policy and those issues in the ANPR that are of interest to the interstate natural gas pipeline industry and our customers. INGAA supports the thrust of the comments of the U.S. Chamber of Commerce and the American Gas Association (AGA), which examine both the legal questions associated with regulating GHGs under the existing CAA and the economy-wide burden that would be created by the various schemes suggested in the ANPR.

INGAA strongly supports continuing scientific analysis to inform the ongoing discussion of GHG regulation. This is especially important given the unique nature of GHGs and the global challenge of climate change, which presents a fundamentally different environmental concern than controlling the regional pollutant emissions that the CAA was designed to address.

A. INGAA Guiding Principles for Climate Change Policy

The interstate natural gas pipeline industry's contribution to overall U.S. GHG emissions[6] is relatively small. According to the EPA inventory of GHGs,[7] in 2006, natural gas producers, processors, pipelines and distributors together accounted for approximately 3.2% of overall U.S. emissions. Natural gas pipelines accounted for less than 1% of overall U.S. emissions.[8] Our industry prides itself on environmental stewardship and we are proud of the role natural gas will continue to play in reducing net emissions over the next several years. Many

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6 Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) and three groups of fluorinated gases (sulfur hexafluoride, HFCs, and PFCs) are the major greenhouse gases. The primary GHG emissions attributable to the natural gas transmission industry include CO_2 from combustion sources and methane from fugitive emissions (leaks) and venting.

7 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006, (EPA, USEPA #430-R-08-005, April 2008).

8 As will be noted later in these comments, the production, transportation, and consumption of natural gas accounts for nearly 20% of all U.S. CO_2 emissions and 18% of total U.S. GHG emissions (on a CO_2-equivalent basis).

INGAA members participate in EPA's successful Natural Gas Star Program,[9] and, as noted in EPA's 2007 program summary, these "transmission partners" have reduced ethane emissions by over 195[10] billion cubic feet (the GHG equivalent of 78 million tonnes of CO_2) since the program's inception in 1993.

As mentioned, INGAA encourages the development of a mandatory federal climate change program, enacted by Congress, which would preempt redundant and potentially conflicting state or regional initiatives. INGAA has encouraged lawmakers to ensure that climate change policies:

1. Minimize the burden on the economy and do not cause undue harm to the natural gas pipeline industry and its customers.
2. Recognize that the use of natural gas should be part of any climate change policy and do not discriminate against natural gas relative to other fossil fuels;
3. Rely on market-based approaches that are simple to administer and provide clear price signals that permit industry to select the most efficient and cost-effective solutions;
4. Recognize that, if a cap and trade policy is developed, the point of regulation, and consequent responsibility for possession and surrender of any allowances should not be placed upon service providers such as transporting pipelines;
5. Ensure that early efforts to reduce GHG emissions are recognized and rewarded;
6. Support research and development and appropriate funding for technology development to reduce greenhouse gas emissions, including those from our facilities;
7. Recognize and does not compromise the existing regulatory structure at the Federal Energy Regulatory Commission;
8. Encourage the U.S. EPA and other agencies to adopt policies consistent with a national approach.
9. Provide a new, comprehensive regulatory program that reflects the unique attributes and objectives of managing greenhouse gas emissions.
10. Do not disadvantage American industries relative to our foreign counterparts.

9 See http://www.epa.gov/gasstar/partners/index.html (listing participants).

10 See http://www.epa.gov/gasstar/accomplishments/index.html#eight (listing accomplishments).

B. Natural Gas Will Provide a Bridge to a Less Carbon Intensive Economy

Natural gas is efficient and clean. Its CO_2 content is substantially less than any other fossil fuel (in some cases by almost 50%). Pending the widespread deployment of renewable, nuclear or other "clean energy" technologies, something that may take several decades to achieve, natural gas will be an essential and critical part of the U.S. energy portfolio. Climate change policies must recognize this reality and allow natural gas to play its critical role as a bridge fuel.

As the U.S. economy moves to reduce GHG emissions, natural gas will have an important role to play. The role of natural gas as bridge fuel, balancing energy demand, energy security, and environmental goals, may be a long one — lasting several decades — because natural gas is the cleanest burning fossil fuel. Natural gas is already recognized as a clean source of fuel for generating electricity and has in fact been the fuel of choice for the vast majority of new electrical generating capacity built in the U.S. over the last ten years. Also, natural gas is a vital, value-added feedstock in chemical manufacturing and many other industries, and it is an extremely efficient and cost effective fuel for home heating, water heating, stovetops and other direct uses.

The carbon content of natural gas (measured in CO_2 emissions per unit of energy) is 44% less than the carbon content of coal. Moreover, because of the relative efficiency of currently-deployed gas combustion technologies, the carbon advantages of natural gas are even greater when considering CO_2 emissions per unit of electricity output. As shown on Table 1 below, the CO_2 emission rate for generating electricity from natural gas is less than half the rate for generating electricity from coal.

Table 1: Carbon Content of Fossil Fuels[11]		
Fuel	**Metric Tons of Carbon per Billion Btu**	**Metric Tons of CO_2 Per MWh (2005 Average)**
Coal	26.0	0.99
Oil	20.3	0.79
Natural gas	14.5	0.47

A well balanced energy portfolio is needed, employing all fossil fuels, renewable sources, nuclear and hydro facilities. The deployment of new nuclear generating stations and clean coal technologies (*e.g.*, IGCC and carbon sequestration) will take years to achieve significant market penetration and, during this transition period, natural gas-fired power plants will be one of the few low-emissions alternatives for generating the electricity needed to keep pace with increasing demand (as well as the capacity needs that may result from the retirement of less efficient and higher emitting older generators) And, while solar and wind fueled electricity technology must play an increasing role in meeting our nation's energy needs, these technologies still continue to depend on natural gas-fired generation to compensate for their intermittent availability.

According the World Energy Outlook, world primary energy demand is forecasted to grow by 1.6% per year on average between 2006 and 2030 – an increase of 45%.[12] Any federal climate policy is inextricably linked to the national energy policy. Therefore, the two polices must be optimized to ensure real energy demand and energy security concerns are addressed, while mitigating potential risks from climate change. Hence, GHG regulation must be crafted with an eye toward the effect on the nation's energy and economic security. Indeed, the Department of Energy expressed particular concern that regulation of GHGs under the CAA

11 See, Energy Information Administration, Documentation for Emissions of Greenhouse Gas in the United States 2006, Table 6-1; Energy Information Administration, *Annual Energy Review*, 2005, Tables 8.2b, 2.1f.

12 World Energy Outlook 2008, ISBN 978-92-64-04560-6.

could have significant adverse effects on U.S. energy supplies, reliability, and security.[13] INGAA urges EPA to consider the comments of the DOE, especially with regard to the importance of natural gas as part of the Nation's energy portfolio. The broader policy impacts must be considered, especially given the likelihood that the nation will rely heavily on natural gas should we fail to expand nuclear power production and cost-effectively deploy carbon capture and storage.

II. If EPA Proceeds To Rulemaking In This Area, The Agency Should Exercise Its Lawful Discretion To Approach This Matter With The Utmost Circumspection.

INGAA agrees with EPA Administrator Johnson that the CAA is not appropriate for dealing with global warming and the proper course is for Congress to address GHG emissions through new legislation.[14] INGAA appreciates that EPA is approaching this issue with serious reservation, and INGAA understands that the ANPR represents EPA's effort to address the Supreme Court's decision in *Massachusetts v. EPA*[15] in the face of Congressional inaction.[16] The potential economic consequences associated with GHG regulation under the CAA are

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13 See ANPR, 73 Fed. Reg. 44368 ("While the Department has general concerns about the portrayal of likely effects of proposals to regulate GHGs under the CAA on all sectors of the U.S. economy, DOE is particularly concerned about the effects of such regulation on the energy sector. The effects of broad based, economy-wide regulation of GHGs under the CAA would have significant adverse effects on U.S. energy supplies, energy reliability, and energy security.") (Department of Energy preliminary comments)

14 "EPA Says Congress Needs To Regulate Greenhouse Gases, Not Administration," CQ Daily (Jul. 11, 2008). Administrator Johnson expressed similar sentiments in his preface to the ANPR: "I believe the [ANOPR] demonstrates the [CAA], an outdated law originally enacted to control regional pollutants that cause direct health effects, is ill-suited for the task of regulating global greenhouse gases." ANPR, 73 Fed. Reg. at 44355.

15 549 U.S. 497 (2007).

16 See ANPR, 73 Fed. Reg. at 44397 ("[T]he ANPR illustrates the complexity and interconnections inherent in CAA regulation of GHGs. These complexities reflect that the CAA was not specifically designed to address GHGs and illustrate the opportunity for new legislation to reduce regulatory complexity. However, unless and until Congress acts, the existing CAA will be applied in its current form.") (emphasis added).

massive,[17] and EPA must therefore use all of its discretion, both within *Massachusetts* and under broader concepts of administrative law, to give itself the time required to collect all material information and to consider, weigh and deliberate the potential benefits and consequences of each relevant regulatory option.

Indeed *Massachusetts* leaves EPA considerable discretion. The opinion acknowledges, "EPA no doubt has significant latitude as to the manner, timing, content, and coordination of its regulations with those of other agencies."[18] It is imperative EPA makes full use of its judicially recognized latitude, particularly with regard to the "manner, timing and content" of any decision concerning endangerment.[19]

The Supreme Court did not prejudge endangerment; in fact, it recognized EPA's latitude to consider policy implications within the parameters of the CAA:

> We need not and do not reach the question whether on remand EPA must make an endangerment finding, or whether policy concerns can inform EPA's actions in the event that it makes such a finding. We hold only that EPA must ground its reasons for action or inaction in the statute.[20]

The ANPR has an entire section devoted to listing all of the scientific, legal and policy issues that must be investigated, weighed and resolved as part of an endangerment analysis. The

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17 The U.S. Chamber of Commerce found that regulating greenhouse gases under the CAA would cause 1,000,000 commercial buildings, nearly 200,000 manufacturing operations and about 20,000 large farms to become CAA-regulated stationary sources. A Regulatory Burden: The Compliance Dimension of Regulating CO_2 as a Pollutant, Portia M. E. Mills and Mark P. Mills (U.S. Chamber of Commerce Sep. 2008).

18 *Massachusetts v. EPA* , Slip Op. at 30.

19 Two federal courts have already denied petitions for writs of mandamus that would have compelled EPA to issue endangerment findings. *Massachusetts v. EPA*, Dkt. No. 03-1361 (D. C. Cir. Jun. 26, 2008) (*per curium*); *S. F. Chapter of A. Philip Roth Inst. v. EPA,* 2008 U. S. Dist. LEXIS 27794 at *10-11 (N. D. Cal. Mar. 28, 2008).

20 *Massachusetts v. EPA* , Slip Op. at 32 (internal citation omitted); see also ANPR, 73 Fed. Reg. at 44398.

preliminary comments from the Department of Energy give a sense of the scope and depth of these issues:

> [B]ased on the text of section 202(a) of the Clean Air Act, any EPA "endangerment" finding must address a number of issues that involve interpretation of statutory terms and the application of technical or scientific data and judgment. For example, an endangerment determination must involve, among other things, a decision about the meaning of statutory terms including "reasonably be anticipated to," "cause, or contribute to," "endanger," and "public health or welfare." Moreover, because the Act refers to "air pollutant" in the singular, presumably EPA should make any endangerment finding as to individual greenhouse gases and not as to all GHGs taken together, but this also is a matter that EPA must address and resolve. There are other issues that must be resolved as well, such as: whether the "public health and welfare" should be evaluated with respect to the United States alone or, if foreign impacts can or should or must be addressed as well, what the statutory basis is for doing so and for basing U.S. emissions controls on foreign impacts; what time period in the future is relevant for purposes of determining what is "reasonably anticipate[d]"; whether and if so how EPA must evaluate any beneficial impacts of GHG emissions in the United States or elsewhere in making an endangerment determination; and whether a particular volume of emissions or a particular effect from such emissions from new motor vehicles must be found before EPA may make a "cause or contribute" finding, since the Act explicitly calls for the EPA Administrator to exercise his "judgment," and presumably that judgment involves more than simply a mechanistic calculation that one or more molecules will be emitted.[21]

These issues would need to be examined and resolved even if the endangerment analysis is limited to CAA Section 202(a), the only section at issue in *Massachusetts*. But the potential impact of this decision is not limited to Section 202(a). The Department of Energy (DOE)[22] and others[23] have observed that an endangerment finding under Section 202 would trigger GHG

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21 ANPR, 73 Fed. Reg. at 44366-67.

22 *E.g.*, Id. at 44367 ("If EPA were to address these issues and resolve them in favor of a positive endangerment finding under section 202(a) of the Act with respect to one or more greenhouse gases and in favor of regulating GHG emissions from new motor vehicles, then the language similarities of various sections of the CAA likely would require EPA also to regulate GHG emissions from stationary sources.") (Department of Energy preliminary comments).

23 See generally, Comments of the Chamber of Commerce of the United States of America (filed Nov. 19, 2008).

regulation under numerous sections of the CAA, including provisions regulating stationary sources. The ANPR recognizes this cascade effect and seeks comments on it.[24] Without prejudging the issue,[25] if and to the extent there is a cascade effect, the depth and scope of the endangerment analysis increases several fold, since every element within that analysis will need to be examined for its potential effect on every other form of CAA regulation of mobile and stationary sources.

Beyond *Massachusetts*, EPA enjoys the same latitude possessed by all administrative agencies to order, organize and manage its affairs as necessary to fulfill its congressionally delegated duties. The ANPR recognizes this latitude, albeit in the narrow context of whether EPA can use general permits to carry out the prevention of significant deterioration (PSD) program:

> Certain limited grounds for the creation of exemptions are inherent in the administrative process, and their unavailability under a statutory scheme should not be presumed, save in the face of the most unambiguous demonstration of congressional intent to foreclose them. The Court identified several types of administrative relief. One is "[c]ategorical exemptions from the clear commands of a regulatory statute," which the court stated are "sometimes permitted," but emphasized that they "are not favored. A second is "an administrative approach not explicitly provided in the statute," such as "streamlined agency approaches or procedures where the conventional course, typically case-by-case determinations, would, as a practical matter, prevent the agency from carrying out the mission assigned to it by Congress." A third is a delay of deadlines upon "'a showing by [the agency] that publication of some of the guidelines by that date is infeasible.'". The Court indicated it would evaluate these choices based on the "administrative need to adjust to available resources * * * where the constraint

24 ANPR, 73 Fed. Reg. at 44420.

25 Rather than presuming the existence of a cascade effect, INGAA strongly urges the EPA to review the text and legislative history of each the CAA's endangerment provisions to assess the presence, nature and significance of any differences that would prompt a distinct endangerment analysis of otherwise prevent the cascade from occurring.

> was imposed * * * by a shortage of funds * * *, by a shortage of time, or [by a shortage] of the technical personnel needed to administer a program.[26]

INGAA urges EPA to take full advantage of its managerial flexibility, particularly with regard to deciding which GHGs and which sources to address first.

As EPA examines endangerment and the other issues posed in this docket, INGAA urges EPA to be thorough and complete, consistent with the significance of these issues to both our environment and our economy.

III. Regulating Natural Gas Related GHGs Poses Unique Challenges And Thus Warrants Special Consideration.

Clean-burning natural gas is an increasingly important, readily available source of North American energy that helps fuel our nation's economy while achieving our environmental goals. Over 84% of the natural gas consumed in the U.S. is produced domestically and 98% is produced in North America. Natural gas is used in over 63 percent of U.S. homes[27] and is vital to America's manufacturers, not only to power their operations, but also as an essential feedstock for many of the products we use daily. It is a primary feedstock for chemicals, plastics and fertilizers. Natural gas is efficient; indeed some 90% of the natural gas produced in the U.S. is delivered to customers as usable energy. Natural gas is also abundant; there are enough domestic gas resources to meet consumer needs for generations. Energy from natural gas accounts for 24% of total energy consumed in the U.S., making it a vital component of our nation's energy supply.

The production, transportation, and consumption of natural gas accounts for nearly 20% of all U.S. CO_2 emissions and 18% of total U.S. GHG emissions (on a CO_2-equivalent or CO_2e

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[26] ANPR, 73 Fed. Reg. at 44503 (quoting *Alabama Power*, *supra*, 636 F.2d at 357-58, in turn quoting *NRDC v. Train*, 510 F.2d 692, 712 (D.C. Cir. 1974)).

[27] Energy Information Administration (http://www.eia.doe.gov/kids/energyfacts).

basis). However, the natural gas value chain prior to end-users (exploration, production, processing, transmission and distribution) account for about 3% of the total US GHG emissions.

There are different regulatory oversight bodies over the natural gas value chain. For example, the interstate transmission and storage entities are regulated by the Federal Energy Regulatory Commission (FERC), whereas local distribution companies (LDCs) and intra-state pipelines are regulated by the state public utility commissions and the exploration and processing segments may not be regulated. This diversity of regulatory settings is an added complexity that must be carefully analyzed and understood by the EPA or another GHG regulating entity.

Hence, at the same time, as the cleanest burning fossil fuel, natural gas will be an essential and critical part of the U.S. energy mix for the foreseeable future and care must be taken not to undermine its use and availability. For this reason, any GHG regulation on the natural gas sector must consider the existing unique technical and legal considerations.

A. GHG Cap-And-Trade Programs

The ANPR stated objectives include a discussion of the "issues and approaches for designing GHG control measures that are useful in developing either regulations or legislation to reduce GHG emissions."[28] While the CAA does not authorize "economy-wide" programs or emissions taxes, Congress is considering climate change legislation, and a number of bills call for reducing GHG emissions from a wide variety of sources by using a "cap-and-trade"

[28] ANPR, 73 Fed. Reg. at 44397.

approach. Should EPA determine that a cap-and-trade program[29] can be used under the CAA to regulate GHG emissions, a central issue in the design of a GHG cap-and-trade program is how to regulate emissions associated with the use of natural gas, because the natural gas sector presents challenges not found in regulating CO_2 emissions from coal use and petroleum use. In particular:

- The principal GHG concern for the sector is CO_2 emissions from natural gas combustion. End-users of natural gas number in the millions, and include not only large industrial facilities and electricity generators, but also a wide variety of smaller users in the commercial and residential sectors. For these small-volume end users the costs of participation in a cap-and-trade program could be prohibitive, but energy efficiency efforts, which can be implemented on a programmatic basis, have already proven to be extremely effective.
- From production to end-use, the natural gas supply chain involves a number of different types of entities. In a number of cases, rate regulation or market circumstances affect the extent to which these entities can pass through costs of environmental regulation.
- Both physical possession and, in many cases, ownership of the natural gas commodity change multiple times within the value chain between natural gas producers and end use consumers; downstream regulation at the point of combustion eliminates administrative complications associated with upstream regulation of such a market.
- The natural gas sector also generates fugitive emissions of methane (another GHG), which are difficult to measure and monitor, but which can be addressed through programmatic measures that seek to minimize fugitive emissions.

B. Criteria for a Workable GHG Cap and Trade Program

To be workable and efficient, a GHG program must provide consumers with price signals that create incentives for conserving fuels and/or switching to fuels with less severe GHG impacts. This means that the full cost of the emissions allowances (allowances) — the price

[29] On July 11, 2008, the D.C. Circuit vacated EPA's Clean Air Interstate Rule (CAIR) and in the process, brought into question the legality of EPA employing regional cap and trade programs to achieve the goals of the CAA. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). On September 24, 2008, EPA filed a petition for rehearing in the case, effectively making it unclear whether EPA will have authority to create trading programs as part of the CAA. A range of interested parties (including members of Congress, State officials, the environmental community, and representatives of industry) have begun considering short term legislative options to ensure the use of trading programs.

signal that will motivate the decisions that should be the object of GHG impact policy — should flow through to those who are in the best position to influence their emissions: end users.

A workable and efficient GHG program should also be comprehensive by covering the largest possible amount of GHG emissions. This will spread the adjustment processes more widely and fairly and reduce the total social cost of achieving compliance (by more efficiently finding the lowest-cost source of conservation or switching) without creating incentives for strategic behavior to bypass the program.

Once the first two criteria are met, the program should be manageable from an administrative perspective by minimizing the number of points of regulation to the greatest extent possible, by employing a transparent accounting mechanism that requires as little new information as possible while avoiding duplicative regulation of any energy or fuel delivered to consumers. While administrative efficiency is an important concern, it cannot be the determinative variable in making critical program decisions, such as where to establish the point of regulation.

C. Criteria for Selecting the Point of Regulation

A particularly important issue is whether to adopt upstream, midstream or downstream approaches to GHG regulation of the natural gas sector. Upstream and midstream approaches would limit emissions from end-users by regulating the entities that produce, process, transport or distribute natural gas, even though these entities have no direct control over combustion, the primary source of emissions. As presented in Senate Bill 2191 (the Lieberman-Warner Climate Security Act of 2007) these entities would be required to acquire and retire emission allowances equal to the CO_2 emissions potential of their natural gas throughput. The simplistic assumption implicit in this approach is that this cost would be passed through to consumers of gas, providing the same economic incentive for reductions as regulation at the point of emissions (downstream).

As discussed above, a basic criterion for selecting the points of regulation for a cap-and-trade program is the ability to pass through allowance costs (for upstream approaches). Selecting interstate natural gas pipelines as the point of regulation could present substantial problems, particularly with regard to cost pass-through, for several reasons.

Interstate transmission pipelines do not own the natural gas they transport. Like common carrier trucking firms, interstate transmission pipelines are transportation service providers. Thus, increasing the price for transportation service would not necessarily increase the resale price of the natural gas commodity. Moreover, pipeline transportation rates are subject to rate regulation by the FERC, and interstate transmission pipelines cannot pass through new regulatory costs without FERC approval. The fact that pipelines are subject to rate regulation has important implications.

Most notably, it means that pipelines would incur discontinuities in their efforts to pass through allowance costs. The models calling for upstream regulation assume that allowance costs will reach end-users. While interstate pipelines have a reasonable expectation that regulators will authorize a mechanism for recovering from ratepayers the costs incurred as a result of a mandatory carbon control program, due to market realities there still remain significant risks that pipelines would not realize 100 percent cost pass through.

It is important to note that, even in cases in which a pipeline is allowed a rate that provides for full recovery of its regulatory or costs, it might not charge this maximum rate, due to the wide-spread market practice of competitive discounting. Given these obstacles, among other considerations, an approach that would impose the allowance requirement directly on the pipelines will likely not result in efficient cost pass-through.

INGAA has reviewed these issues and the available data on gas flows and emissions of GHGs related to the natural gas sector. Our analysis included an estimate of the coverage of gas-related emissions under several program designs, including:

- Upstream - Producers and Importers – coverage based on CO_2 potential of throughput at producers and importers.
- Upstream - Processors and Importers – coverage based on CO_2 potential of throughput at natural gas processors and importers.
- Upstream - Pipelines – coverage based on CO_2 potential of throughput at natural gas pipelines.
- Downstream - Large Sources – coverage based on regulation of any facility that emits more than 10,000 tons CO_2eq per year of GHG.
- Downstream - Large Sources + LDCs – coverage based on regulation of any facility that emits more than 10,000 tons CO_2eq per year of GHG plus the CO_2 potential of LDC throughput to smaller gas consumers.

Table 2 summarizes the analysis of GHG coverage. The “producers and importers” and “large sources and LDCs” options both have nearly complete coverage of the CO_2 from combustion of gas. The latter option has greater overall coverage due to the inclusion of methane emissions. The “large sources only” option has the lowest coverage due to the exclusion of the residential/commercial sectors, even though it includes methane emissions. The coverage of the “processors and importers” option is only slightly higher due to the quantity of gas that is not processed and lack of coverage of methane. The coverage of the “pipelines” option falls in the middle.

Table 2 Gas Sector Coverage Summary							
	Tonnes CO_2	Coverage of Gas-Related CO_2*	Tonnes from Methane	Total Tonnes	Total GHG %	Entities	Facilities
Upstream - Producers + Importers	1,106	94%	0	1,106	86%	825	700,536
Upstream - Processors + Importers	825	70%	0	825	64%	365	566
Upstream – Pipelines	1,025	87%	0	1,025	80%	132	27,750
Downstream - Large Sources Only	618	53%	100	718	56%	5,562	8,780
Downstream - Large Sources + LDCs	1,113	95%	100	1,213	94%	5,712	11,780

* Includes CO_2 from gas combustion and non-energy CO_2 from gas processing plants.

As discussed above, selecting interstate natural gas pipelines as the point of regulation would present substantial problems, particularly with regard to cost pass-through. The INGAA paper "*Point of Regulation for the Natural Gas Sector: Issues and Options*" provides a more detailed discussion of the point of regulation for the natural gas industry and the executive summary from this paper is included as Appendix A.

IV. There are significant implications for natural gas transmission sources if GHGs are regulated under Section 111, Section 112, or the NSR/PSD program.

INGAA agrees with EPA's assertion in the ANPR preamble that the CAA is ill-suited for regulating GHGs and that any such regulation would likely be problematic and ineffective as a means of implementing a comprehensive climate change policy. As mentioned earlier, GHG emissions from interstate transmission companies are generally from a myriad of small sources. A number of examples are provided below that illustrate the complications, burdens and costs that would be borne by the natural gas transmission sector if regulation was implemented under any of the primary sections of the CAA. These burdens are frequently driven by the relatively small emission sources that would be implicated. The implementing regulatory agencies would also be burdened by the need to address standards development and implementation, including the current lack of data necessary to develop those standards and a large increase in the number of permit applications to be processed. The discussion below considers many facets of the CAA and implications for the natural gas transmission sector, including:

- ✦ The context and regulatory thresholds of existing CAA regulations could implicate very small equipment: *e.g.*, a 60 horsepower internal combustion (IC) engine or 45 kilowatt turbine under Section 111; or, a 2.4 hp IC engine, all turbines, and many single family home furnaces under Section 112. Regulations could affect both new and existing equipment of such small size, introducing significant compliance and enforcement costs without yielding commensurate benefits.
- ✦ Permitting requirements for the natural gas sector could introduce extraordinary burdens for both operators and regulatory agencies, with a high probability of permitting delays or gridlock. Permitting delays could have negative consequences for the safety and reliability of the natural gas pipeline system and the nation's energy infrastructure.
- ✦ There is a paucity of data to develop GHG regulations using the processes and structure of the CAA, including limitations associated with defining emission control requirements, developing regulations, and implementing NSPS, NESHAP, and PSD/NSR requirements.
- ✦ The ANPR expresses unwarranted optimism about the potential to adopt market-based approaches to regulation under existing Clean Air Act authority. If EPA proceeds to regulate GHGs under the Act, the appellate courts will likely require a command-and-control approach. This legal risk is such that regulated entities would be reluctant to utilize or rely on market-based approaches even if they were part of an EPA rulemaking on GHG emissions from stationary sources.
- ✦ Given the large number of new sources that would exceed current Clean Air Act emission thresholds (if applied to GHGs), the Agency would face extraordinary challenges in tailoring performance standards and BACT definitions to consider the unique equipment attributes in different sectors or applications (*e.g.*, equipment "subcategories" within a rule) properly. A lack of attention to this level of detail could introduce operational constraints that negatively impact operational flexibility with potential repercussions throughout the economy.

To be clear, this cost burden would be felt not just by the industry but also by natural gas consumers in residential, commercial, industrial and utility markets. The discussion below provides primary examples of difficulties that would be encountered by the natural gas transmission industry from regulation under Section 111 New Source Performance Standards (NSPS), Section 112 National Emission Standards for Hazardous Air Pollutants (NESHAPs), the New Source Review / Prevention of Significant Deterioration (NSR/PSD) program, and related Title V permitting obligations.

A. Section 111 NSPS – Example Issues for Natural Gas Transmission

1. Gas transmission systems include a number of components potentially subject to GHG regulation under Section 111 (*i.e.*, reciprocating engines, turbines, small boilers/process heaters, *etc*.). If not properly limited in scope, NSPS regulations could reach thousands of natural gas sector emission sources, and hundreds of thousands of sources economy-wide. This would result in inordinate compliance and administrative burdens for both the natural gas transmission sector and the administrative agency.

Section 111 requires EPA to issue new source performance standards (NSPS) governing pollutant emissions from categories of stationary sources designated by EPA. NSPS already exist for the primary equipment used in natural gas transmission, *i.e.*, reciprocating IC engines and turbines that drive natural gas compressors. These "prime movers" maintain pipeline pressures to ensure the safe, reliable delivery of natural gas to consumers throughout the U.S. and are an integral component of the U.S. energy infrastructure. In addition, NSPS already apply to other small combustion sources such as natural gas-fired boilers and line heaters which are sometimes used at natural gas transmission compressor stations.

Because they are covered by current NSPS, these sources would likely also be targets of a revised performance standard if GHGs are regulated under Section 111.

It is not clear how a GHG NSPS would be integrated with the current NOx-based standards for combustion equipment, because GHG technology or work practice-based standards do not align well with the current NSPS format, and the current NSPS regulatory thresholds capture inconsequential GHG emission sources. For combustion equipment, NSPS include: presumptive emission limits based on best demonstrated technology; equipment specific monitoring and recordkeeping requirements; and, size-based thresholds that capture small equipment. GHG efficiency standards, work practices, or flexible regulatory approaches are not consistent with the regulatory format of existing combustion NSPS. In addition, unit-specific requirements typical for NSPS would result in significant compliance costs for the very small GHG sources potentially implicated. Based on current NSPS size-based applicability thresholds, nearly all combustion equipment in natural gas transmission would exceed the regulatory threshold if thresholds are retained at the same level as current standards. For example, natural gas-fired reciprocating IC engines are NSPS affected sources under Subpart JJJJ regardless of size. Thus, a large number of very small new sources would need to address GHG requirements under this regulatory paradigm. In addition to IC engines and turbines that drive compressors, NSPS for GHG emissions from natural gas pipelines could affect trivial combustion sources such as small line heaters and emergency generators at communication towers.

These complications would affect not just new pipelines but existing facilities as well, including thousands of pieces of equipment at pipeline facilities, because GHG requirements under the NSPS would apply to existing sources that undergo modification or reconstruction. This modification provision currently applies to pipeline NSPS for currently regulated pollutants (*e.g.*, NOx), but could prove especially troublesome under a GHG regulatory scheme that introduces additional technology or work practice standards. To address modification, sources would need to ensure that no increase in CO_2 or other GHGs occurs after any physical or operational change is made to pipeline equipment. The number of modifications triggering application of NSPS is potentially quite large. Understanding and tracking "any increase" in CO_2 emissions could prove challenging for operators and difficult to consistently interpret for regulatory agencies.

In addition to the equipment used on natural gas transmission pipelines, there are hundreds of thousands of similar units (*e.g.*, IC engines, boilers, process heaters, valves, flanges, pneumatic devices) throughout the country. Under Section 111, all of this affected equipment would bear new costs associated with control, compliance monitoring, reporting, recordkeeping, and permitting. These costs and requirements would place undue stress on not only the affected sources, but also the federal and state agencies that develop and adopt regulations, address determinations related to applicability and implementation, and fulfill permitting and enforcement responsibilities. The breadth and depth of these requirements would introduce huge financial and economic burden on both the affected community of sources and the administrative agencies responsible for implementation.

2. Inadequate data exists to define best demonstrated technologies for purposes of establishing NSPS.

INGAA appreciates EPA's cautious approach to the inclusion of GHG in NSPS thus far, as well as the Agency's recognition that more sector-specific data is required in order to determine whether NSPS in certain existing source categories should cover GHG emissions.[30] INGAA believes that the natural gas pipeline sector presents significant operational and technological constraints that make NSPS a particularly unsuitable regulatory approach for GHGs.

NSPS development for GHGs would require EPA to determine the best demonstrated technology for each listed category of stationary sources. Operators already have an inherent financial incentive to minimize fuel consumption and gas losses during operation — both resulting in GHG emissions — through efficient combustion practices and proper operating and maintenance procedures. This operating approach ensures the reliability and availability of the equipment that serves as the backbone of our national natural gas supply system.

[30] ANPR, 73 Fed. Reg. at 44487.

INGAA agrees with EPA that Section 111 requires a current demonstration of the availability of control technologies that bring emissions to "feasible and cost-effective levels."[31] There are currently no feasible "add-on" controls or technology solutions that result in lower GHG emissions from combustion equipment at pipelines. In addition, there is no data or information available to serve as the basis for defining best demonstrated technology (BDT) for natural gas transmission compressor drivers or similar equipment in other industrial sectors. Thus, the basis for developing an NSPS is questionable due to the paucity of technical data to substantiate a BDT determination or the associated emission standard. For broad equipment categories such as reciprocating IC engines, industrial boilers, *etc*., there are also operational constraints inherent in different applications that could affect the feasibility of a standard premised on improved efficiency to reduce CO_2 emissions.

For example, engines in gas transmission must be able to operate over a wide load range and often exhibit load swings in response to pipeline demands — which is driven by natural gas consumers. However, at times of reduced operating load the fuel consumption per unit of energy output (*e.g.*, Btu/bhp-hr) increases, negatively impacting efficiency. This vital load flexibility could be compromised if EPA institutes GHG standards or combustion work practices that do not properly account for operational requirements. Also, any demands to improve efficiency of equipment must be viewed carefully through existing NSPS and PSD regulatory interpretation and guidance. As cited by many EPA decisions, efforts by companies to improve efficiency or reliability for operational or safety reasons have been viewed as triggers for PSD and NSPS modification. Such policies could essentially discourage investment and therefore reduction in GHG mitigation technologies.

31 ANPR, 73 Fed. Reg. at 44490.

Also, these operational differences across the economy would be compounded as a GHG NSPS would broadly implicate additional industrial, commercial and residential applications that have previously been unaffected by the NSPS. This presents another challenge in standard development, *i.e.*, ensuring adequate consideration of industry-specific constraints in an NSPS that would affect a broad array of sources and applications.

The diversity of operating functions and conditions of various GHG sources only increases the magnitude of EPA's data requirements for developing NSPS. EPA will need to develop an extensive factual record in order to craft source subcategories that avoid precluding important commercial activities, such as reliable delivery of natural gas to consumers. The information challenge presented would be inordinately difficult to overcome. This one example is a small subset of the challenges that would be presented across the array of source categories and operations affected under Section 111.

3. Regulation under Section 111 would introduce inordinate costs for natural gas transmission sources without commensurate environmental benefit, resulting in implications for the U.S. energy infrastructure that are difficult to forecast. Resulting complications could trigger existing source controls under modification or reconstruction provisions, broad state permitting requirements for small Section 111 sources, *etc*.

Regulation under Section 111 via an NSPS for natural gas transmission sources would introduce inordinate compliance costs, as <u>all</u> new, reconstructed, or modified combustion sources in the sector would likely be affected given current statutory thresholds. As discussed above, natural gas transmission is a relatively minor contributor to the U.S. GHG inventory and represents a small percentage of the GHG emissions from natural gas systems and usage. Operations already strive for efficiency to minimize operating costs, within the constraints of operational flexibility required to meet pipeline demand. Thus, regulation would likely result in relatively insignificant emission benefits, despite imposing full implementation costs associated with NSPS compliance, including permitting, control technology, compliance monitoring, and reporting and recordkeeping burden. The significant compliance costs would be borne by many whose contribution to greenhouse gas emissions is trivial. NSPS compliance would also add to permitting delays, therefore making conversion to cleaner burning natural gas and ultimately renewable sources of energy a longer-term proposition.

The breadth and depth of coverage required for an effective command-and-control NSPS scheme would result in significant burdens with very little environmental benefit, both for initial implementation and for ongoing operation and compliance assurance. Every natural gas transmission compressor station and many emission sources associated therewith would be impacted by regulation under Section 111. For example, a small generator at a remote communication tower site would likely be affected and very small compressor station equipment such as line heaters or building heaters would be implicated. The impacts would be significant and, given the discretionary and other uncertainties built into the Section 111 process, are difficult to forecast with precision at this point, but will surely include higher energy costs and possible energy infrastructure reliability concerns as new source construction or existing source upgrades are impacted by a deluge of new and lengthy permitting requirements.

Although NSPS focus on new sources, existing sources would also be implicated, especially through the modification provisions of NSPS. In addition to NSPS burden, small sources that were previously considered “exempt” facilities could become subject to state permitting burdens where states mandate permits for NSPS affected sources. Collectively, the implications for natural gas transmission are very broad and will impact every facet of our operations. Ultimately, due to the breadth of coverage, inefficiencies in this mechanism for

GHG regulation, and marginal reductions that would be achieved, Section 111 would introduce inordinate costs for natural gas transmission that result in minimal emissions or environmental benefits. This presents a significant challenge to any clean energy transition strategy.

4. The court rejection of the CAIR and CAMR regulations indicate that EPA may not have authority to develop cap-and-trade market-based regulations under Section 111.

INGAA supports market-based approaches to regulation of air pollutants, which is why we are very concerned about recent court decisions that call into question EPA's claimed authority to initiate a cap-and-trade program under CAA Section 111. In the ANPR, EPA asserts that a cap-and-trade program for GHGs would satisfy the definition of a "standard of performance" for purposes of the NSPS program even though the CAA does not explicitly authorize the use of trading for NSPS.[32] If EPA chooses to proceed under this assumption, it may find that the appellate courts do not share such an expansive reading of the term. Indeed, two recent decisions by the D.C. Circuit vacating major EPA rules have applied an exceedingly narrow interpretation of the CAA.

One of these cases is *New Jersey v. EPA*,[33] in which the D.C. Circuit invalidated the Clean Air Mercury Rule (CAMR). The CAMR removed mercury emitted from coal-fired power plants from the list of Hazardous Air Pollutants, and instead authorized a cap-and-trade program for mercury under Section 111. Environmental organizations challenging the CAMR argued that the plain language of Sections 111(d)(1) and 302(l) require a "standard of performance" to achieve "<u>continuous</u> emission reductions" from <u>specific</u> sources. They asserted that a cap-and-trade program would violate this requirement by mandating <u>sector-wide</u> reductions that could,

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32 ANPR, 73 Fed. Reg. at 44490.

33 517 F.3d 574 (D.C. Cir. 2008).

due to trading, allow particular sources to increase their emissions over time.[34] These petitioners also cited *ASARCO v. EPA*,[35] in which the D.C. Circuit rejected an EPA interpretation of Section 111 that would have allowed limited trading of emissions between regulated sources at the same industrial site.[36] The *New Jersey* court did not reach these arguments, because it held that EPA improperly delisted power plant mercury under Section 112 and thus lacked any authority whatsoever to address this pollutant through the NSPS program.[37] However, the Court demonstrated hostility to EPA's flexible application of administrative law principles, recourse to historical practice, and attempt to interpret the delisting provisions of Section 112 in light of the listing provisions. The Court emphasized that Section 112 called for EPA to make certain findings before delisting "any" source category, and refused to defer to EPA's own past practice and the Agency's own interpretation of the statute.[38]

A similarly strict reading of the CAA carried the day in *North Carolina v. EPA*,[39] in which the court of appeals vacated the Clean Air Interstate Rule (CAIR). Although this was not a Section 111 case, the Court's decision is nonetheless relevant because it found that the plain meaning of CAA Section 110 (governing State Implementation Plans or SIPs) foreclosed a regional cap-and-trade program under CAIR. The Court particularly focused on the provision in Section 110 that specifies that SIPs must prohibit sources "within the State" from "contributing

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34 Final Opening Brief of Environmental Petitioners, at 25-27.

35 578 F.2d 319 (D.C. Cir. 1978).

36 Id. at 28-29.

37 *New Jersey*, 517 F.3d at 583-84.

38 Id. at 582-83.

39 531 F.3d 896 (D.C. Cir 2008).

significantly to nonattainment in any other State."[40] The D.C. Circuit reasoned that, because regional emissions trading might allow some states to maintain or increase their emissions, CAIR could not guarantee that sources "within" a state would cease contributing significantly to nonattainment in other states. EPA's policy arguments proved unavailing against the Court's textual analysis, as did its emphasis that CAIR would comply with the statute by using regional abatement to achieve attainment in each State. This reading of Section 110 calls into question whether EPA could implement a cap-and-trade program under Section 111 when the terms of that section appear to call for source-specific and "continuous" emissions reductions.

These legal developments are important, because a NSPS program directed at GHGs would, absent emissions trading, be immensely inefficient and costly. As suggested above, NSPS without trading is a classic "command-and-control" regulatory regime that requires all equivalent emission sources to achieve the same level of abatement, regardless of marginal cost. Sources facing low marginal abatement costs would have no incentive to continue reducing emissions past the performance standard. Other sources facing high abatement costs will either shut down or incur the cost to reduce emissions that could be more cost effectively reduced elsewhere.

For these reasons, INGAA members are deeply troubled by the ANPR's suggestion that EPA could implement the NSPS or other CAA-related provisions through a cap-and-trade program. This is an area of great uncertainty, and the consequences of EPA misinterpreting the scope of its authority, potentially leaving source-specific performance standards standing alone, would be severe.

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[40] *North Carolina*, 531 F.3d at 907-08.

B. NSR / PSD – Example Issues for Natural Gas Transmission:

1. The ANPR grossly underestimates the amount of PSD review needed, with an EPA estimate of about 2000–3000 NSR permit reviews annually (a 10 fold increase). When an installation of a mere 0.49 MMBtu/hr combustion source triggers the NSR major source threshold, we agree with the U.S. Chamber of Commerce assertion that there may be over a million NSR "major sources" nationwide.

INGAA agrees with EPA's general assessment that the PSD program, as currently structured, would snare many insignificantly small sources of GHG emissions and significantly increase permitting burdens for EPA and the states.[41] In the ANPR, EPA estimates a tenfold increase in NSR permit reviews. INGAA concurs with the U.S. Chamber of Commerce assertion that this is a gross underestimate,[42] and INGAA believes that NSR/PSD review would impose a huge burden on both regulated sources and permitting agencies. Examples of potentially affected equipment capacities for combustion units common in natural gas transmission indicate that sources previously considered trivial and exempt would be implicated based on the current NSR/PSD thresholds for major source, or an emissions change at an existing major source.

Based on the NSR major source threshold of 250 tons per year (TPY), the CO_2 potential to emit would exceed the major source level for a 0.49 MMBtu/hr natural gas combustor. Example equipment size for this heat input rate includes:

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41 ANPR, 73 Fed. Reg. at 44500.

42 A Regulatory Burden: The Compliance Dimension of Regulating CO_2 as a Pollutant, Portia M. E. Mills and Mark P. Mills (U.S. Chamber of Commerce Sep. 2008).

- A 60 horsepower IC engine (*i.e.*, all natural gas transmission compressor drivers and the vast majority of stationary engines nationwide);
- A 45 kilowatt gas turbine (*i.e.*, all industrial turbines and nearly all "microturbines" nationwide);
- A boiler or process heater that is more than 20 times smaller than the NSPS regulatory threshold for small industrial, commercial or institutional steam generating units (*i.e.*, 40 CFR 60, Subpart Dc, includes an applicability threshold of 10 MMBtu/hr).

Similarly, when considering NSR/PSD review for an emissions change at an existing major source, and assuming a significance threshold of 40 TPY in increased emissions resulting from the change, the addition of equipment 6.25 times smaller than the capacity in the bullets above would trigger review. And many interstate pipeline companies operate in severe and extreme non attainment areas with lower significance thresholds. Regardless, the 250 TPY major source threshold and the 40 TPY significant emission change threshold are the least stringent under the existing NSR/PSD program, and more stringent thresholds could be possible using the current NSR/PSD model, depending upon GHG program design and implementation.

A regulation that reached equipment of such small size would confer major source status on all industrial, commercial and institutional sources across the U.S. and would even encompass some residential units. For natural gas transmission, all prime movers exceed these thresholds, and even small line heaters, small auxiliary generators, emergency generators, *etc.* would result in major source status or trigger review when added to an existing source. This would impact all facilities and operations in natural gas transmission. Economy-wide NSR would have an enormous regulatory impact capturing hundreds of thousands of sources. At current emission thresholds, the vast majority of U.S. stationary combustion sources would be subsumed into the NSR/PSD program.

2. INGAA members transport natural gas that is vital for the nation's energy needs and security, and our facilities are maintained in a safe and reliable manner to ensure safe delivery. We are concerned that extremely low significance thresholds, uncertainties over Routine Maintenance Repair and Replacement (RMRR) activities, or delays in RMRR agency determinations would raise the pipeline industry's safety and reliability risk – if such maintenance activities need agency review or approval.

GHG-related NSR requirements would create severe technical complications for pipelines if these requirements were triggered by the GHG programs under CAA Sections 108 or 111. One area of complication stems from the requirement that PSD/NNSR permits be obtained before a major modification to an existing stationary source. In addition, the distinction between a "major modification" and RMRR is unclear in the context of GHG regulation.

INGAA members operate complex networks of pipelines spanning thousands of miles, the proper and timely maintenance of which is vital to ensuring a safe and dependable supply of energy. A failure at any one of the multitude of components comprising these systems would introduce serious safety and reliability risks for INGAA members. Yet, as EPA notes in the ANPR, current significance thresholds under the PSD and NSR programs are so low that even modifications enabling just a few minutes' additional utilization of a facility could trigger EPA review.[43]

Moreover, it is uncertain how the RMRR exemption would be interpreted for complex pipeline systems affected by a GHG regulation. EPA has traditionally applied an unpredictable, case-by-case analysis to define this "de minimis" RMRR category of modifications,[44] which continues today in light of the failure of EPA's recent attempt to exclude categorically certain

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[43] ANPR, 73 Fed. Reg. at 44499.

[44] See *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901 (7th Cir 1990).

"modifications" through the Equipment Replacement Provision.[45] If EPA does not clarify what forms of RMRR are exempt from PSD/NSR, and does not adjust the significance threshold for an increase in emissions resulting from a modification, the Agency will be inundated with NSR permit applications and face a substantial risk of administrative paralysis. Since NSR permitting is a precondition for modifications, this gridlock would delay vital repair and maintenance for months or years at facilities owned by INGAA members. These delays could have serious implications for projects that address pipeline system efficiency and safety improvements.

3. There is a paucity of data and information to address key NSR/PSD principles such as BACT or LAER, and the review process for BACT/LAER determination would be required for insignificant sources such as line heaters at a compressor station.

If PSD/NSR review applies, there is a process that must be followed in determining appropriate controls. Assuming that EPA does not deem the entire country to be in "nonattainment" for GHG concentrations,, Best Available Control Technology (BACT) review would apply (rather than LAER). As discussed above, this review would be triggered for trivial sources, *e.g.*, small IC engines, small boilers or heaters. In addition, for prime movers at compressor stations, trivial changes that may increase emissions very marginally could conceivably require review — or at least documentation and a determination that operational changes did not result in a CO_2 increase above the significance threshold. EPA acknowledged in its NSR reform rule that NSR permitting typically takes a few months to two years,[46] and this

45 See *New York v. EPA*, 443 F.3d 880 (D.C. Cir. 2006) (vacating the Equipment Replacement Provision as contrary to the Clean Air Act, which requires that "any" modification increasing emissions come under New Source Review).

46 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects*, 67 Fed. Reg. 80185, 80207 (2002).

timing would surely be severely impacted by the extraordinary permitting influx if NSR/PSD applied to GHGs.

Due to the trivial size of sources and activities potentially affected, along with consideration of new types of emissions, (*e.g.*, CO_2), data and other support information are not available to complete the review and the BACT analysis process would need to be developed and refined over time. In addition, process principles related to technological feasibility or economic feasibility for GHG BACT are not available and would need to be developed and refined. Thus, problems with addressing the likely deluge of permit applications or applicability determinations would be compounded by the paucity of data on emissions, controls, and costs associated with reviewing and implementing GHG BACT. This would exacerbate the enormous challenge that would be associated with NSR/PSD permitting for GHG sources.

4. The permitting implications of all of the above NSR issues would likely result in permitting gridlock affecting the safety and reliability of delivering clean burning natural gas, which may result in potential energy security and infrastructure implications. This would affect not just our sector but would place tremendous burdens on EPA and the state agencies involved in the review of such applications.

The examples discussed above identify natural gas transmission issues, and also note economy-wide implications. Natural gas transmission represents a relatively small sector within the scheme of GHG emissions, and the economy-wide implications for permit applications, regulatory determinations, and permit issuance would present potentially insurmountable challenges.

In the view of INGAA members, the NSR program as it is currently implemented would prove unworkable in the context of GHG emissions. By EPA's own estimates, the annual rate of PSD permit applications for new major sources would increase tenfold were NSR to be applied to GHGs.[47] An additional 550,000 existing facilities would be potentially subject to NSR requirements for major modifications. As noted in the comments above, INGAA firmly believes that the number of facilities ultimately mired in the NSR process would be even higher. For example, EPA's estimates are based on actual emissions, not the potential to emit (PTE), and many small sources that would become NSR major sources have probably been underestimated. Due to this vast expansion of EPA (and state-level agencies) permitting responsibilities, it is unreasonable to anticipate permitting would be completed without substantial delays and administrative gridlock. Additional burden would be incurred from activities such as EPA applicability determination requests, which would surely skyrocket for all energy projects, including natural gas pipeline facilities. This raises serious concerns about whether necessary gas transmission system updates and upgrades could be completed on a timely basis. If not, there are implications regarding the reliable availability of natural gas to consumers, possible implications for U.S. energy and GHG policy, and a potentially significant challenge could be presented for any associated clean energy transition strategy..

Moreover, specific implementation issues would directly affect natural gas transmission sources. EPA's traditional "case-by-case" determination as to what activities constitute RMRR has already led to prolonged litigation. This vague approach will create uncertainties of even greater magnitude when applied to numerous large and small emitters of GHGs, discouraging vital maintenance and repair. More particular to gas pipelines, the technology standards that are applied through NSR permits will prove difficult to define and will suffer from a lack of adequate data. Lastly, the current methods for computing PTE are likely to afford little relief for pipelines under a potential NSR regime for GHGs, since pipelines are required by FERC to build

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47 ANPR, 73 Fed. Reg. at 44499.

systems that are capable of meeting peak demand days and are thus capable of emitting far more GHGs than are actually released in practice.

For gas pipelines that depend on continuous maintenance and investment, this gridlock and uncertainty would result in potentially serious risks to operational safety and reliability, as well as to national energy security.

C. NESHAPs

1. GHGs should not be regulated as HAPs, as EPA and others have concluded that there are no direct ambient health risks from greenhouse gas emissions.

EPA acknowledges in the ANPR preamble "that ambient GHG concentration present no health risks."[48] INGAA agrees with EPA's assertion that it does not have before it credible or sufficient scientific data to show any direct risk to human health from ambient GHG concentration. Regulation of HAPs under Section 112 is intended to address adverse health impacts from listed pollutants. Since GHGs do not fit this criterion, GHGs should not be regulated as HAPs.

2. Major source regulatory thresholds under Section 112 would affect all natural gas transmissions sources, and inappropriately include very small sources.

Major source applicability for other CAA sections is discussed in comments above, and the implications are even worse under Section 112. If CO_2 is regulated under Section 112, the 10 ton-per-year (TPY) major source threshold for a single HAP would apply. Considering the combustion equipment discussed above relative to NSR/PSD thresholds, natural gas-fired equipment of the following sizes would have a CO_2 potential to emit of 10 TPY:

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48 ANPR, 73 Fed. Reg. at 44368.

- A 2.4 horsepower IC engine (*i.e.*, all stationary IC engines);
- A 1.8 kilowatt gas turbine (*i.e.*, all turbines);
- A boiler, water heater, or process heater with a heat input of 19,500 Btu/hr (0.02 MMBtu/hr), which is more than 500 times smaller than the NSPS regulatory threshold for small industrial, commercial or institutional steam generating units. This encompasses all but the smallest residential space heaters, home furnaces, and water heaters.

Even if applicability were based on actual rather than potential emissions and equipment is used sparingly, very small combustion sources that are typically exempt from permitting would trigger "major source" applicability under Section 112. For example, CO_2 emissions from a 42 hp natural gas-fired emergency generator used at a communication tower that is limited to 500 annual operating hours would exceed the major source threshold. All natural gas transmission facilities and any industrial or commercial operation with a combustor would be classified as a major source, as would multi-family residences and many single family homes. The implications and resulting compliance and administrative burden would be enormous. Clearly, Section 112 is a very poor vehicle for GHG regulation.

3. Regulation under Section 112 would introduce significant burden for standard development and implementation. For example, the "MACT floor" would need to be determined for existing sources and new source standards would need to be developed. Such standards would require operational data and related information that is currently inadequate or unavailable.

As noted above, a multitude of stationary combustion equipment nationwide would trigger the application of Section 112 under the current statutory emission thresholds. Since most of this equipment already falls within Section 112 source categories, EPA would be mandated to develop Maximum Achievable Control Technology (MACT) standards for combustors, including clean burning natural gas-fired equipment. The size thresholds noted above would result in these standards applying to nearly all stationary combustion equipment.

The courts and EPA have given the MACT provisions of Section 112 a rigid interpretation that prevent EPA from promulgating standards that take into account a lack of current control technologies or costs of compliance. EPA would be required to consider emissions from *existing* sources and develop an emission standard for those units. Recent court cases have held EPA must develop an emission standard even when the "MACT Floor" (*i.e.*, average emission limitation of the best performing 12 percent) for existing equipment involves no technological emission controls.[49] Furthermore, the agency has taken the position that it may not consider cost for the MACT floor determination. In addition, for new units, EPA would be required to base the standard on the best performing similar source. Thus, standards would be required for nearly every combustion device in use and new unit installed. Subcategories are a means to differentiate source types within the MACT standard based on technological or emissions performance characteristics, and there would likely be a need for a multitude of subcategories within the MACT standards for IC engines (Part 63, Subpart ZZZZ), turbines (Part 63, Subpart YYYY), and boilers (Part 63, Subpart DDDDD). Information is not currently available to support development of these GHG standards under Section 112.

The paucity of data to support key principles in MACT development would challenge the ability to develop a reasoned standard that addresses Section 112 requirements, especially when one considers the breadth of sources and applications covered. For example, it is unlikely that there is information available to inform the MACT floor or new source MACT decision for the breadth of affected combustors, especially for very small units. In addition, information about applicable controls, work practices, compliance monitoring approaches, *etc*. would be sorely

[49] See *Sierra Club v. EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007) (invalidating an EPA rule requiring no HAP emission controls for a subcategory of kilns in which the "best performers" used no control technology); *National Lime Association v. EPA*, 233 F.3d 625, 633 (D.C. Cir. 2000) (invalidating a "no control" emission standard for HAP emitted by cement plants).

lacking. Collectively, the lack of data and background information would likely impose an insurmountable barrier to developing MACT standards within a reasonable timeframe.

4. There would be significant impacts for gas transmission sources under Section 112 because our operations are included in listed source categories. This would result in inordinate costs associated with rigorous NESHAP criteria.

The natural gas transmission industry would be significantly impacted, because nearly all facets of our operations are within Section 112 listed source categories. In addition to combustion sources with Part 63 regulations identified above, the transmission and storage (T&S) sector is regulated under Part 63, Subpart HHH. This regulation primarily affects relatively large dehydrators at storage facilities, with MACT requirements for facility IC engines, turbines, and other combustors addressed by the respective combustion MACT. However, with inclusion of GHGs, Subpart HHH would need to consider additional sources, perhaps including fugitive methane emissions. Thus, nearly all natural gas transmission operations would be directly impacted by regulation under Section 112.

The breadth of control that would result for natural gas transmission through this avenue would probably be the most costly of any under the existing CAA. NESHAP criteria are especially rigorous and result in considerable compliance obligation. For example, Part 63 Subpart A (General Provisions) includes rigorous requirements related to testing, monitoring, notifications, recordkeeping and reporting. The costs associated with the paperwork and reporting burden present one the largest challenges for NESHAPs. With GHG regulation under Section 112 capturing trivially small sources, the resulting cost and operating burden would be exorbitant, and would be difficult for operators to implement and for agencies to adequately address. Imposing such new administrative burden on small sources without an expectation that such regulation will have the effect of reducing emissions cannot reflect sound policy.

5. If GHGs are regulated under Section 112, there is a high likelihood of numerous "delisting" petitions.

EPA has developed a list of subject source categories as mandated by Section 112(c)(1), and this list includes the combustion units and T&S category discussed above. However, Section 112(c)(9)(B) provides an avenue to delete source categories (or subcategories within a source category) from the list of affected sources if no source in the category poses an adverse effect. EPA is required to act on a petition to delist within one year after the petition is filed. EPA and others have indicated that GHGs do not pose an adverse health effect. Thus, it is highly likely that a multitude of petitions would be submitted to request delisting for either the entire source category or a subcategory of otherwise affected equipment.

The delisting process would incur considerable expense and burden to both the petitioning party and EPA, and the number of petitions would likely overwhelm EPA's ability to respond. Thus, regulation under Section 112 would be a regulatory path likely to result in gridlock, as rule development, implementation, and delisting petitions inundate the system and the ability to respond.

D. Title V

1. Previously insignificant and trivial sources would need to be incorporated into the Title V program, resulting in a significant administrative burden for "new" major sources that require Title V permits and for existing permit revisions to address new applicable requirements. The administrative burden would be contrary to EPA White Papers and existing Title V program policies.

INGAA's concerns over administrative gridlock in applying NSR to GHG sources apply equally to the administration of the Title V operating permits program. Title V permits create an additional administrative burden for applicants and permitting authorities, which would be particularly severe in that it would immediately require operating permits for any source emitting more than 100 TPY of an air pollutant — an extremely low threshold that would snare even some residential and commercial buildings. As EPA acknowledges, this would result in a tenfold increase in the number of facilities applying to permitting authorities for Title V permits. Many of these sources would account for de minimis levels of GHG emissions, and may not even be subject to specific GHG regulations (depending on which other actions EPA takes under the CAA).[50] Thus, EPA and permitting authorities would embark on a massive administrative undertaking with, in many cases, little environmental benefit.

CONCLUSION

Climate change imposes huge environmental and economic challenges, and INGAA truly appreciates this opportunity examine these challenges from the perspective of the nation's natural gas transmission pipelines. We look forward to participating in an ongoing dialog about these issues, and we stand ready to address any questions that may arise concerning these comments.

Respectfully submitted,

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50 ANPR, 73 Fed. Reg. at 44510.

ATTACHMENT

Point of Regulation for the Natural Gas Sector: Issues and Options

(INGAA: November 2008)

Interstate Natural Gas Association of America

Point of Regulation for the Natural Gas Sector: Issues and Options

November 2008

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Point of Regulation for the Natural Gas Sector: Issues and Options

Executive Summary

A central issue in the design of a federal economy-wide greenhouse gas (GHG) cap-and-trade program is how to regulate emissions associated with use of natural gas. Bills introduced in Congress have reflected a range of different approaches. Indeed, different versions of the Lieberman-Warner bill (S. 2191) have incorporated different approaches.

GHG emissions associated with natural gas make up a significant portion of total U.S. GHG emissions. The production, transportation, and consumption of natural gas accounts for 20 percent of all U.S. carbon dioxide (CO_2) emissions and 18 percent of total U.S. GHG emissions (on a CO_2-equivalent basis). For this reason, it is important to ensure that emissions from the natural gas sector are covered in a manner that is environmentally effective, efficient, and fair.

Regulation of the natural gas sector presents challenges not found in regulating CO_2 emissions from coal use and petroleum use. In particular:

- End-users of natural gas number in the millions, and include not only large industrial facilities and electricity generators, but also a wide variety of smaller users in the commercial and residential sectors.

- There are a number of different types of entities in the natural gas supply chain from production to end-use. In a number of cases, rate regulation or market circumstances impact the extent to which these entities can pass through costs of environmental regulation.

- Both physical possession and, in many cases, ownership of the natural gas commodity change multiple times within the value chain between natural gas producers and end use consumers.

- Although the principal GHG concern for the sector is CO_2 emissions from natural gas combustion, the sector also generates fugitive emissions of methane (another GHG), which are difficult to measure and monitor.

A particularly important issue is whether to adopt “upstream,” “midstream” or “downstream” approaches to GHG regulation of the sector. “Upstream” and “midstream” approaches would “cover” emissions by end-users by regulating entities that produce, process, transport or distribute natural gas. These entities would be required to acquire and retire emission allowances equal to the CO_2 emissions potential of their gas throughput. This cost would theoretically be passed through to consumers of gas and provide the same economic incentive for reductions as a cap-and-trade program at the point of emissions (“downstream”).

This white paper reviews these issues and the available data on gas flows and emissions of GHGs related to the natural gas sector. The analysis includes an estimate of the coverage of gas-related emissions under several program designs, including:

- Upstream - Producers + Importers – coverage based on CO_2 potential of throughput at producers and importers.
- Upstream - Processors + Importers – coverage based on CO_2 potential of throughput at natural gas processors and importers.
- Upstream - Pipelines – coverage based on CO_2 potential of throughput at natural gas pipelines.
- Downstream - Large Sources – coverage based on regulation of any facility that emits more than 10,000 tons CO_2eq per year of GHG.
- Downstream - Large Sources + LDCs – coverage based on regulation of any facility that emits more than 10,000 tons CO_2eq per year of GHG plus the CO_2 potential of LDC throughput to smaller gas consumers.

Table 1 and Figure 1 summarize the analysis of GHG coverage. The –"producer + imports" option and the "large source + LDC" option both have nearly complete coverage of the CO_2 from combustion of gas. The latter option has greater overall coverage due to the inclusion of methane emissions. The "large source only" option has the lowest coverage due to the exclusion of the residential/commercial sectors, even though it includes methane emissions. The coverage of the "processor + imports" option is only slightly higher due to gas that is not processed and lack of coverage of methane. The coverage of the pipeline option falls in the middle. Issues associated with cost pass-through and program efficiency for each option are also discussed in the white paper.

Table 1
Gas Sector Coverage Summary

	Tonnes CO_2	Coverage of Gas-Related CO_2*	Tonnes from Methane	Total Tonnes	Total GHG %	Entities	Facilities
Upstream - Producers + Importers	1,106	94%	0	1,106	86%	825	700,536
Upstream - Processors + Importers	825	70%	0	825	64%	365	566
Upstream – Pipelines	1,025	87%	0	1,025	80%	132	27,750
Downstream - Large Sources	618	53%	100	718	56%	5,562	8,780
Downstream - Large Sources + LDCs	1,113	95%	100	1,213	94%	5,712	11,780

* Includes CO_2 from gas combustion and non-energy CO_2 from gas processing plants.

Figure 1
Gas Sector Coverage Summary