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COVERAGE OF NATURAL GAS EMISSIONS AND FLOWS UNDER A GREENHOUSE GAS CAP-AND-TRADE PROGRAM

by

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PEW CENTER ON Global CLIMATE CHANGE

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The author and the Pew Center would like to thank all those who reviewed and provided advice on previous drafts of this paper, including Steven Crookshank of American Petroleum Institute, Tracy Terry of the National Commission on Energy Policy, and Bob Nordhaus of Van Ness Feldman.

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I. Overview

Greenhouse gas (GHG) emissions associated with natural gas make up nearly 18 percent of total U.S. GHG emissions.[1] Regulation of GHG emissions from the natural gas sector under a cap-and-trade program presents challenges different from those associated with coal or petroleum for several reasons:

- 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.
- Although the principal GHG concern for the sector is carbon dioxide (CO_2) emissions from natural gas combustion, the sector also generates non-energy CO_2 emissions and fugitive emissions of methane (CH_4), which are difficult to measure and monitor.[2]
- There are a number of different types of entities in the natural gas supply chain from production to end use making it difficult to apply the standard upstream vs. downstream dichotomy traditionally used to think about the point of regulation for petroleum and coal under cap-and-trade programs.
- Both physical possession and, in many cases, ownership of the natural gas commodity change multiple times within the value chain as natural gas moves from producers to end-use consumers.

These factors have made the treatment of natural gas a challenging issue in the design of a federal economy-wide GHG cap-and-trade program.[3] Bills introduced in Congress have reflected a range of different approaches.[4] Even different versions of the Lieberman-Warner bill (S. 2191) incorporated different approaches.

A particularly important design issue is whether to directly regulate GHG emitters or to regulate firms for the embedded emissions of the fossil fuels that they produce, process, transport, or distribute.[5] For fossil fuels like natural gas, embedded emissions are the GHG emissions that will ultimately be emitted once the fuel is combusted (see box below for a discussion of the direct vs. embedded emissions and upstream vs. downstream points of regulation). A point of regulation for natural gas coverage under cap and trade that regulates embedded emissions would cover emissions by end users indirectly through the regulation of entities/facilities that produce, process, transport, or distribute natural gas.[6] Under a cap-and-trade program, these entities/facilities would be required to acquire and retire emission allowances equal to their embedded emissions—i.e. the CO_2 emissions from combustion of the natural gas that these entities/facilities produce, process, transport, or distribute. In theory, entities regulated for their embedded emissions would pass the cost of allowances on to consumers of natural gas thus providing the same economic incentive for emission reductions on the part of emitters as would a cap-and-trade program that regulated direct emissions.[7]

The reason for interest in regulating embedded emissions is that it may be possible to, in effect, cover the direct emissions of many diverse emission sources by regulating the embedded emissions of relatively few entities that produce, process, transport, or deliver fossil fuels. For example, GHG emissions from many millions of motor vehicles could be covered under cap and trade via regulation of the embedded emissions of approximately 150 U.S. oil refiners plus some importers of fuel. That said, there is concern as to whether in practice the price signal established by regulating embedded emissions is an efficient or effective way to ensure GHG reductions from end users.

In considering the point-of-regulation options, one must consider what percentage of GHG emissions from the natural gas sector each option would cover and how many and what kinds of entities/facilities would need to be regulated. The latter question is important from the perspective of allowing for the accurate measurement of direct emissions by regulated entities/facilities or embedded emissions from natural gas produced, processed, transported, or distributed by regulated entitities/facilities. Moreover, all else equal, a cap-and-trade program that limits the number of entities/facilities that must be monitored for compliance limits the associated administrative costs borne by government and industry. One should also consider the efficiency with which different point-of-regulation options achieve emission reductions because of differences in compliance options and responsiveness to price signals among entities at different points along the natural gas value chain. This last question is the subject of a forthcoming paper.

The following sections of this paper review the emissions profile of the natural gas sector, identify the key entities and associated facilities in the natural gas supply chain, provide an estimate of the emissions coverage and number of entities and facilities regulated under various point-of-regulation options, and provide a summary of the analysis.

Upstream vs. Downstream Points of Regulation and Embedded vs. Direct Emissions

Many analyses of possible points of regulation for covering fossil fuel use under cap and trade describe different options as being either upstream or downstream. The terms upstream and downstream refer to the position along the fossil fuel value chain from extraction to emission. For example, an upstream point of regulation for coal would regulate coal at the mine-mouth whereas a downstream point of regulation would regulate firms that consume coal (via combustion or gasification) and emit CO_2.

For the oil and gas industries, the upstream vs. downstream distinction can be confusing because the same terminology is used in these industries to designate different segments of the industries. Upstream refers to production and processing, while downstream refers to the delivery segments of the industry. Transmission may be referred to as downstream or midstream.

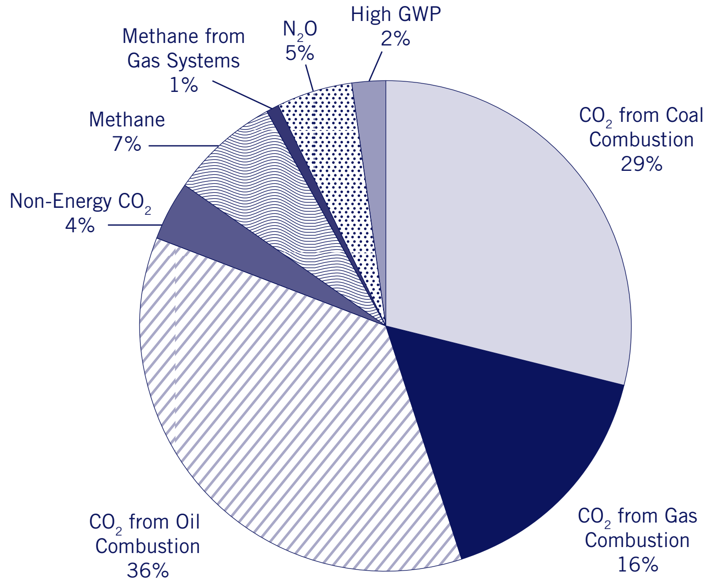
This can be particularly confusing because some facilities involved in upstream activities such as gas producers and processors are themselves large direct emitters of GHGs and thus are downstream facilities from an emissions perspective. To avoid confusion, rather than describing potential points of regulation for natural gas as upstream or downstream, this paper differentiates between options that regulate direct emissions of GHGs from natural gas and those that regulate embedded emissions.

As used in this paper, the term direct emissions refers to actual releases of GHGs into the atmosphere—i.e. CO_2 from the combustion of natural gas and CO_2 removed from raw natural gas during processing. Entities/facilities along the entire natural gas value chain can be the source of direct emissions, including natural gas processing plants, pipeline compressor stations, and gas-fired industrial boilers. In the context of this paper, the term embedded emissions refers to the GHGs that will be released from natural gas at some point along the value chain. For example, if one considers the natural gas extracted by a producer, this natural gas has embedded emissions equal to the CO_2 that will be released from combustion of the natural gas irrespective of where along the natural gas value chain from producer to end user the combustion takes place.

II. GHG Emissions from the Natural Gas Sector

The natural gas sector contributes to U.S. GHG emissions in three ways. The largest is CO_2 from the combustion of natural gas, which comprised 1,155 million metric tons CO_2e ($MMTCO_2e$) or 16 percent of the total U.S. GHG inventory in 2006 (Figure 1).[8,9]

Figure 1: U.S. GHG Emissions by Fuel and Gas ($MMTCO_2e$), 2006[10]



Total = 7,054 $MMTCO_2e$

Fugitive emissions and venting of natural gas comprise a second component of GHG emissions related to natural gas.[11] Natural gas is composed primarily of methane (CH_4), which is itself a GHG with a global warming potential 21 times greater than CO_2.[12] Fugitive methane emissions from the natural gas industry account for approximately 102 $MMTCO_2e$ or about 1.4 percent of total U.S. GHG emissions and 18 percent of total U.S. methane emissions.

Non-energy CO_2 is the third component of GHG emissions from the natural gas sector. The majority of these emissions come from CO_2 that is part of raw natural gas (formation CO_2) and is removed from the gas as part of the clean-up process.[13] Most of this CO_2 is vented to the atmosphere, though some is captured and used for enhanced oil recovery (EOR).[14] These emissions account for about 29 $MMTCO_2e$ or less than one percent of total U.S. GHG emissions. Together, the natural gas sector accounts for about 1,286 $MMTCO_2e$ or 18 percent of total U.S. GHG emissions on a CO_2-equivalent basis.

Figure 2 shows U.S. GHG emissions by end use, including those associated with natural gas (see Appendix for a table with the same data). CO_2 from natural gas combustion in the industrial sector is the largest component of GHG emissions from natural gas, at 5.3 percent of the total U.S. GHG emissions inventory. CO_2 from combustion of natural gas in the power sector is the second largest component of GHG emissions from natural gas at 4.4 percent of total U.S. GHG emissions, followed by residential gas combustion at 3.6 percent and commercial combustion at 2.3 percent. Combustion of natural gas in the transportation sector, primarily for pipeline compressor fuel, accounted for about 0.4 percent of the total inventory. Fugitive emissions of methane account for 1.4 percent of the total U.S. GHG emissions.

Figure 2: U.S. GHG Emissions by Fuel and Sector, 2006

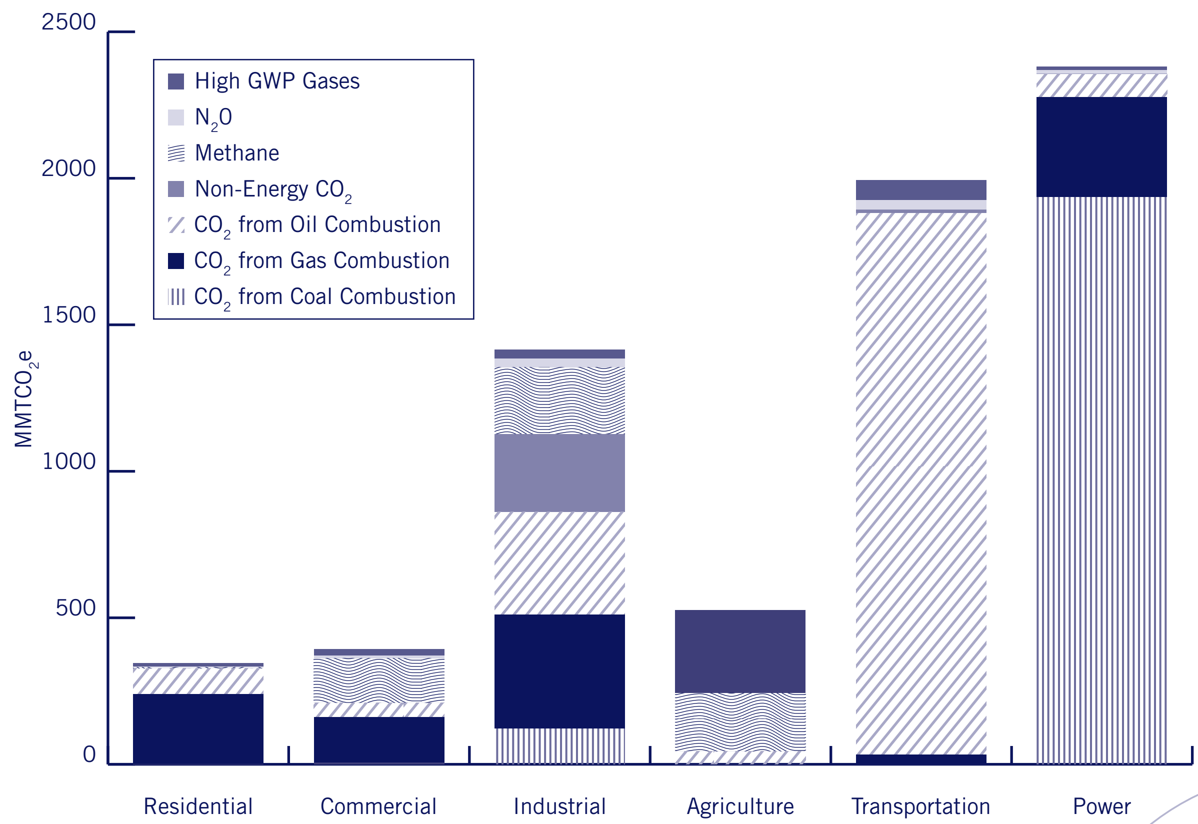


Table 1 breaks down the 2006 GHG emissions from the natural gas industry itself—i.e., from gas production, processing, transmission and storage, and distribution. It does not include GHG emissions from the natural gas industry's operations that come from fuels other than natural gas, such as diesel fuel used to power gas exploration equipment (vehicles and drilling rigs), or from the production of GHGs other than CO_2 and methane. The petroleum-related emissions from the natural gas industry would be covered under programs that regulate emissions from combustion of petroleum. The natural gas industry had natural gas-related GHG emissions of 224 $MMTCO_2e$ in 2006, which constituted 3.2 percent of total U.S. GHG emissions.

Table 1: U.S. Greenhouse Gas Emissions for the Natural Gas Industry (Production, Processing, Transmission and Storage, and Distribution) ($MMTCO_2e$), 2006[15]

	CO_2 From Combustion	Non-Energy CO_2	Methane	Other Gases	Total CO_2e
Production	41.8	7.2	27.6	–	76.6
Processing	19.6	21.2	11.9	–	52.7
Transmission and Storage	32.0	0.1	38.2	–	70.3
Distribution	–	–	24.7	–	24.7
Gas Industry Total	**93.4**	**28.5**	**102.4**	**–**	**224.3**
U.S. Total	**5,637.9**	**345.2**	**555.3**	**515.8**	**7,054.2**
Gas Industry as % of U.S. Total	1.7%	8.3%	18.4%	0.0%	3.2%

Table 1 lists the GHG emissions for the segments of the natural gas industry and the United States. In 2006, natural gas production operations had total emissions of 76.6 $MMTCO_2e$, which included 41.8 $MMTCO_2e$ from the combustion of "lease fuel," gas consumed for operations at the producing site; 7.2 $MMTCO_2e$ from non-energy CO_2 emissions, mostly natural gas flaring; and 27.6 $MMTCO_2e$ from the fugitive release of methane.[16]

Natural gas processing operations had total emissions of 52.7 $MMTCO_2e$, including 19.6 $MMTCO_2e$ from the combustion of "plant fuel," gas combusted in the processing operations; 21.2 $MMTCO_2e$ of non-energy CO_2 emissions, primarily from acid-gas removal units that remove formation CO_2 from natural gas; and 11.9 $MMTCO_2e$ from the fugitive release of methane.

The transmission and storage segment of the natural gas industry had emissions of 70.3 $MMTCO_2e$. This included 32.0 $MMTCO_2e$ from the combustion of pipeline fuel and 38.2 $MMTCO_2e$ from the fugitive release of methane.[17] Distribution operations had emissions of 24.7 $MMTCO_2e$ from the fugitive release of methane.

Overall the gas industry's total GHG emissions comprised 3.2 percent of total U.S. GHG emissions in 2006. The natural gas industry emitted 1.7 percent of total U.S. CO_2 emissions from combustion. Almost half of the GHG emissions from the natural gas industry are from the release of methane, which accounted for 18.4 percent of all U.S methane emissions.

The inclusion of fugitive methane in a cap-and-trade program poses a number of challenges. It is difficult to identify all of the sources of vented and fugitive methane with the level of accuracy necessary to establish a baseline estimate of emissions. Moreover, even when sources are identified, fugitive emissions cannot always be measured to the highly accurate levels commonly required for a cap-and-trade program. For these reasons, the coverage of fugitive emissions is not considered in this paper's discussion of point-of-regulation options. One option for addressing fugitive emissions without placing them under the cap is through offsets.

III. Natural Gas Value Chain

The GHG emissions associated with natural gas production, transportation, and use could potentially be regulated at any point along the value chain. This section identifies and characterizes those points.

A. Natural Gas Producers

Natural gas producers locate, drill for, and produce natural gas from on-shore and off-shore wells. Much of the natural gas is associated gas, natural gas produced from oil wells along with the oil. There are approximately 501,000 producing oil wells in the United States.[18] Although most of these also produce natural gas initially, the natural gas production declines over time. Only about half of the oil wells are currently also producing natural gas. Non-associated gas is produced from non-oil bearing formations. The U.S. Energy Information Administration (EIA) reports that non-associated natural gas is produced in this country from approximately 450,000 wells.[19] Including the non-associated gas wells and half the oil wells gives a total of about 700,500 gas-producing wells. Gross withdrawals of natural gas in 2006 totaled approximately 18 trillion cubic feet (Tcf) from gas wells and 5.6 Tcf from oil wells.[20] The total value of 23.5 Tcf gross withdrawals includes the value of gas that is reinjected underground, consumed in production and processing operations, and natural gas liquids that are extracted and marketed separately. The treatment of these quantities may vary under different regulatory options, as discussed below. In 2006, total domestic marketed natural gas production was 18 Tcf.

In tracking oil and gas production, the U.S. EIA uses the concept of an operator, an entity responsible for the management and day-to-day operation of a well.[21] EIA distinguishes well operators from royalty owners and working interest owners who are not directly responsible for operations. EIA collects data on oil and natural gas reserves and production under three categories of operators based on annual production volumes: large, those producing over 15 billion cubic feet (Bcf) of natural gas; intermediate, two to 15 Bcf; and small, less than two Bcf. In total, there are nearly 14,000 operators. However, most production is concentrated among large operators. The 173 large operators account for 77.9 percent of domestic natural gas and 79.5 percent of oil production. The 467 intermediate operators account for an additional 15.6 percent of domestic gas and 9.5 percent of oil production. Finally, the 13,180 small operators account for the remaining 6.5 percent of gas and 11 percent of oil production. If the production of associated gas is roughly proportional to the production of oil, the 640 largest operators would account for 92.4 percent of domestic gas production.

Although a relatively small number of operators comprise the vast majority of production, one must also consider the approach to monitoring and verification under a cap-and-trade program. Historically, cap-and-trade programs have generally regulated large point sources and required the monitoring of each individual emitting unit – each stack. If under a GHG cap-and-trade program, individual well data are required for submission and data verification, rather than company-wide data from the operators, then the number of regulated units would be in the hundreds of thousands. That said, detailed data on individual wells are already collected at the state and federal levels and used for royalty and tax payments and other official purposes, so they may be readily acceptable for the purposes of a cap-and-trade program.[22] In some cases, some of the well data may be estimated, which might require review. Tracking of GHG emissions at the wellhead would require reporting of additional information related to the hydrocarbon and CO_2 content of the gas from each well. Producers typically have this type of information today but do not report it. Additionally, regulating operators or owners adds a layer of complexity compared to regulating facilities because of changes in the entities that own or operate facilities over time.

B. Natural Gas Importers

The United States imported 4.2 Tcf of natural gas in 2006. Of this amount, 3.6 Tcf, or 86 percent, came through pipelines — from Canada and, to a lesser extent, Mexico. Another 0.58 Tcf arrived in the form of liquefied natural gas (LNG).[23]

EIA reports that 136 companies were responsible for pipeline imports of natural gas and six companies were responsible for LNG imports. These are companies that held title to the natural gas at the time of import.[24] It is important to distinguish these title-holding companies that import natural gas from the companies that own the LNG terminals and cross-border pipeline facilities that handle the gas at the point of import but do not hold title to the natural gas. Natural gas was imported through 23 cross-border pipelines and five LNG terminals in 2006.[25] About 0.7 Tcf of gas were exported in 2006, mostly via pipeline from the lower 48 states, but also including about 0.06 Tcf of LNG from Alaska.

In establishing a cap-and-trade program that covers natural gas, policymakers would need to decide how to treat natural gas imports and exports. One goal in regulating imports and exports is to promote consistency with the climate policies of other nations. This paper does not consider in detail the question of how to deal with imports and exports under different point-of-regulation options for the United States and its trading partners.

C. Natural Gas Processors

Natural gas exiting the well can contain a wide variety of impurities and non-gas hydrocarbons. Associated gas typically contains liquid as well as gaseous hydrocarbons. Natural gas can also contain water, CO_2, hydrogen sulfide, and other trace impurities. Both contaminants and valuable products are generally removed in several steps. Liquids, including water and liquid hydrocarbons are typically removed through physical separation at the wellhead. The gaseous constituents are then gathered and transported by a small, local pipeline to a central natural gas processing plant. The processing plant uses a variety of compression, cooling, and other processes to remove lighter hydrocarbons, non-hydrocarbon gases, and other impurities. It is only these large processing plants that this paper considers as natural gas processors for the purposes of regulation under cap and trade. The lighter hydrocarbons include propane, butane, and ethane. These are known as natural gas liquids (NGLs). NGLs are used as chemical feedstocks, refinery inputs, and as consumer products. This paper assumes that NGLs would be regulated separately from natural gas under a cap-and-trade program and thus does not consider the direct or embedded emissions from NGLs as part of the natural gas stream.

Some natural gas requires no processing because the unprocessed natural gas meets the pipeline quality standards. However, a certain amount of processing is required for most natural gas to meet pipeline specifications. Other processing, however, is discretionary and is aimed at serving markets for NGLs as separate commodities. The extent to which this additional processing is undertaken is a function of the market demand for natural gas relative to the market demand for commodity NGLs.

EIA tracks 530 natural gas processing plants in the United States and reports that 14.7 Tcf of natural gas was processed in 2006 as compared to total gross withdrawals of 23.5 Tcf and dry production of 18.5 Tcf. [26,27,28] Imported natural gas is normally processed prior to being imported. The exception is the Alliance pipeline from Canada, in which natural gas is imported "wet" and processed in the United States. This volume is about 0.5 Tcf per year. LNG is very "dry" gas due to the cryogenic processes involved in the liquefaction and regasification and, thus, does not require processing after import.

Most prior assessments of coverage at the processor level have been based on EIA's aggregate data on the volume of natural gas processed. However, this does not account for the fact that there is a significant amount of natural gas, about 2.7 Tcf, extracted in Alaska that is processed to remove the NGLs and then reinjected into the ground. Natural gas is produced in Alaska along with oil. There is no way to market most of this natural gas because there is no pipeline to move it to markets in the lower 48 states. The natural gas is therefore reinjected into the producing formation with the idea that it will be re-extracted if and when an Alaskan pipeline is built. However, the natural gas is processed to remove NGLs and impurities before being reinjected, so this natural gas is included in the EIA processing totals. Since this natural gas does not get combusted, it would not be included in a GHG regulatory program. Including only natural gas that is processed and sent to consumers, 11.2 Tcf or 62 percent of dry gas production is processed.

D. Natural Gas Pipelines

Interstate and intrastate pipelines deliver natural gas to local distribution companies (LDCs), directly to some large industrial end users and electricity generators, and to interconnections with other pipelines. Pipelines also transport natural gas to and from storage fields. Shippers frequently transport their gas through more than one pipeline before it reaches an end user.[29] As a consequence of these complications, there is no simple, accurate measure of unique pipeline flows. Based on EIA data (Form 176), we estimate that 89 percent of the total natural gas consumed (including by the natural gas industry itself) flows through pipelines. Some of the 11 percent that does not flow through pipelines is lease and plant gas, which is used in the production and processing of gas prior to the pipeline, and the balance is direct deliveries of natural gas from producers to local distribution companies or large natural gas users near the production areas.[30,31] When one excludes natural gas consumed in the course of production, processing, and transportation of natural gas, one finds that about 94 percent of natural gas actually delivered to end-use consumers flows through interstate and intrastate pipelines.

Due to mergers and consolidation in the gas pipeline industry, some companies own more than one pipeline. Counting each pipeline, there are about 60 interstate and 72 intrastate pipelines in the United States. If the regulation were applied at the level of the entities owning the pipelines, the numbers would be smaller. Although a relatively small number of entities own the pipelines, as in the case of the producers, measurement and compliance assurance would be required at a larger number of facilities, estimated at about 27,750 points where gas enters or leaves the pipelines. As in the case of production from individual wells, these transactions are already tracked for commercial purposes; however, it is uncertain how complicated it would be to resolve pipeline flows for regulatory purposes under cap and trade.

E. Local Distribution Companies (LDCs)

LDCs distribute approximately 65 percent of natural gas consumed by end users. In most circumstances, LDCs purchase and then resell the gas that they deliver to their residential and commercial customers. LDCs charge customers for the natural gas itself and for the delivery of the gas. Generally, the LDCs charge customers only what the LDCs pay for the gas without a markup. The LDCs' earnings and return on investment come from the rates charged for delivery of the gas.

In other cases, LDCs only provide delivery of gas that is owned by the end-use customer or a third party. In these instances, the LDCs do not take ownership of the natural gas commodity. The LDCs provide and are paid only for the distribution services (and storage services if those services are provided using the LDCs' facilities). Historically, such transportation-only service was primarily for large customers who could purchase their own gas from producers. The vast majority of large-volume customers served by LDCs only pay for transportation service from the LDCs and acquire their gas from third parties. In recent years, some states have allowed independent gas marketers to offer gas supply services to small customers, extending the transportation-only market into the residential/commercial sector, including over 4 million customers nationally.

Table 2 shows the breakdown of natural gas distribution to consumers, including sales by LDCs, deliveries by LDCs (gas delivered but not sold by LDCs), and other deliveries (primarily direct pipeline deliveries to customers).[32] LDC sales predominate in the residential sector. Sales and deliveries for LDCs are more evenly split in the commercial sector. LDC sales make up a small fraction of natural gas sales in the industrial and electric generation sectors.

Table 2: Natural Gas Sales by Type and Sector (Tcf), 2006[33]

	LDC Sales	LDC Deliveries	Other Deliveries	Total
Residential	3.9	0.4	0.1	4.4
Commercial	1.7	1.0	0.1	2.8
Industrial	1.5	3.0	2.8	7.4
Electricity Generation	0.2	1.3	3.9	5.4
Total	7.4	5.7	6.9	20.0

There are approximately 1,200 LDCs in the United States, but the largest 150 account for 95 percent of the non-power generation throughput (including both sales and transportation volumes).[34,35] If LDCs are the point of regulation, the compliance liability would need to be on the delivery service rather than the gas commodity in order to cover both sales and transportation customers. It would be up to state utility regulators to determine through rate structures whether LDCs could pass on the cost of the allowances they would need to surrender for the natural gas they deliver. Although 150 is a relatively small number of entities, reporting of the emissions is based on the consumption data from millions of customers. If consumer billing information must be audited for compliance, then tracking emissions would probably be overly complex. However, if billing information is taken to be sufficiently accurate for compliance, then tracking is straightforward at this level.

While the number of LDC entities is small, the number of facilities that might be regulated under a cap-and-trade program with a point of regulation at the LDCs is larger. LDCs might be required to track the gas delivered to their systems. Each physical distribution system typically has a few citygates, points where gas enters the distribution system. However, a large LDC may serve numerous cities/townships or service areas, each potentially with separate citygate delivery points. In some instances, there may be tens or hundreds of individual points where an LDC receives gas. Tracking deliveries at these points would expand the number of measurement points from the 150 LDCs into the thousands or tens of thousands of measurement points, at least.

Because LDCs can determine which customers actually receive the gas, they could be part of a “hybrid” cap-and-trade design in which power generators and large industrial users are regulated directly and smaller emitters are covered via regulation of the LDCs. In this case, there would need to be a system to allow the LDCs to identify which of their customers are covered under cap and trade for their direct emissions so that these customers can be separately tracked and excluded from the LDCs’ compliance liability. This probably requires a regulatory certification of which facilities are regulated under cap and trade for their direct emissions and separate tracking of those facilities.

F. End Users

The end users of natural gas are many and diverse. According to the U.S. EIA, there are about 70 million natural gas consumers, with the vast majority being small residential customers (Table 3).[36]

Table 3: U.S. Natural Gas Consumers (millions), 2006[37]

Consumer Type	Count (million)
Residential	64.4
Commercial	5.3
Industrial (Including Power Generation)	0.2
Total	69.9

Table 4 provides consumption data in trillion cubic feet (Tcf) from EIA for 2006.[38] As discussed above, some natural gas is consumed in the production, processing, and transport links of the natural gas value chain. Most gas is consumed by end users in the residential, commercial, industrial, and electric power sectors. These consumers vary from the very small (homes and commercial enterprises) to large industrial facilities and electric power plants.

Table 4: U.S. Natural Gas Consumption (Tcf), 2006[40]

Natural Gas Consumption	Volume (Tcf)
Volumes Delivered to Consumers	**19.94**
Residential	4.37
Commercial	2.83
Industrial (combustion)	6.49
Industrial (feedstock)	0.60
Vechicle Fuel	0.02
Electric Power	6.22
Lease and Plant Fuel	**1.12**
Lease Fuel	0.76
Plant Fuel	0.36
Pipeline & Distribution Use	**0.58**
Total	**22.25**

The pulp and paper, metals, chemicals, petroleum refining, stone, clay and glass, plastic, and food processing industries account for over 84 percent of all industrial natural gas use.[39] However, as explained below, some of this use is as feedstock rather than for combustion.

G. Non-Emitting Uses of Natural Gas

Some uses of natural gas do not result in GHG emissions. For example, approximately 0.6 Tcf of gas is used as a feedstock in industrial processes, including in chemicals, fertilizers, and pharmaceutical products.[41] These volumes would not be covered in a cap-and-trade program since they do not result in CO_2 emissions from combustion of gas.[42]

IV. Analysis of Coverage for Point-of-Regulation Options

This section estimates the coverage and number of regulated entities and facilities under the natural gas point-of-regulation options below:

A. Producers and importers

B. Processors and importers (Lieberman-Warner approach)

C. Pipelines

D. Pipelines and LDCs

E. Large sources of natural gas-related emissions only

F. Large sources and LDCs

This section estimates what fraction of CO_2 emissions from natural gas combustion could be feasibly covered by each point-of-regulation option as part of a cap-and-trade program. For the purpose of analysis, this section defines the coverable CO_2 emissions from the natural gas sector to include the total natural gas consumption baseline, displayed in Table 4, reduced by 0.6 Tcf to account for gas used as chemical feedstock. This yields 21.65 Tcf of gas consumed for combustion or about 1,155 $MMTCO_2e$. In addition, non-energy CO_2 emissions from natural gas processing, 21.2 $MMTCO_2e$, are included in the coverable emissions because these emissions are part of a well-defined industrial process. In some cases, this CO_2 is being captured today and used for enhanced oil recovery. Non-energy CO_2 emissions associated with natural gas production and transmission, 7.3 $MMTCO_2e$ or 26 percent of total non-energy CO_2 emissions from natural gas, are not included as coverable emissions. Thus, the total coverable emissions from natural gas used in this analysis are 1,155 $MMTCO_2e$ for combustion alone and 1,176.2 $MMTCO_2e$ for combustion plus non-energy CO_2 emissions.

Note that the coverable emissions used in the analysis below include only CO_2 emissions; fugitive methane emissions are not included due to the challenges discussed above. Fugitive emissions could perhaps be addressed under cap and trade via offsets.

A. Option A Producers and Importers

This option sets the point of regulation at the wellhead for domestic production and at the point of import for international production. By definition, this includes all gas consumption and thus gas combustion-related CO_2 emissions, so coverage under this option is theoretically 100 percent of CO_2 emissions from natural gas combustion. Under this cap-and-trade coverage option, producers would need to hold allowances for the embedded emissions of their net production after reinjection. This paper assumes that NGLs would be regulated separately from natural gas under a cap-and-trade program, so producers would only need to hold allowances for the embedded emissions for their net production of natural gas excluding NGLs. This would require a way of accounting for the NGL content at the point of regulation.

Although there are approximately 700,500 gas wells (facilities) in the United States, this program could be implemented at the level of well operator (entity level). The 640 largest operators account for 92.4 percent of natural gas production. This is well within the number of entities that could be regulated in a cap-and-trade program, so we assume 92.4 percent actual coverage of domestic production. Regulating operators or owners adds a layer of complexity compared to regulating facilities because of changes in the entities that own or operate facilities over time, but if monitoring protocols were to require tracking each well individually, then the required number of regulated facilities would be in the hundreds of thousands.

The roughly 13,000 small operators accounting for the remaining 6.5 percent of production would not be explicitly in the cap-and-trade program. However, they are primarily “price takers” which means they sell their production for the current market price. Thus, the price of the unregulated natural gas would likely be the same as the regulated natural gas. Though not explicitly within the program, the unregulated natural gas would transmit the same price signal. That is, small, unregulated producers would likely receive the same price for their natural gas as regulated producers, even though the small producers would not have the requirement to acquire allowances for their throughput.

EIA data identifies 23 pipeline points of entry for natural gas imports and 5 LNG terminals through which natural gas was imported in 2006 (a few more LNG terminals have opened since or will open in the near future). However, there were 136 companies holding title to natural gas who reported pipeline imports in 2006 and 6 companies who reported imports via LNG terminals. The calculation of natural gas consumption must also include exports, which occurred at 13 pipeline points and one LNG terminal. There were 43 companies holding title to natural gas who reported exports in 2006. The total of the large and intermediate producers and the importers and exporters is about 825 entities, a number well within the range that could practicably be included in a cap-and-trade program.

Including the large and intermediate well operators and the importers/exporters, this approach covers 96 percent of CO_2 emissions from natural gas combustion and 94 percent of total natural gas sector CO_2 emissions.

B. Option B Processors and Importers

There are approximately 530 processing plants owned by roughly 180 entities. Most assessments of coverage at the processor level have been based on EIA’s aggregate data on the volume of natural gas processed. However, as noted above, this does not account for the processing of gas reinjected in Alaska. Including only natural gas that is processed and sent to consumers, only 11.2 Tcf or 62 percent of dry production is processed. Including net imports, this puts the total coverage for this option at about 71 percent of coverable CO_2 emissions from natural gas combustion and about 70 percent of coverable CO_2 emissions from the natural gas sector. The processing plants plus importer/exporter facilities comprise about 566 facilities. On an entity basis, there are many more importing/exporting companies than facilities but some co-ownership of processing plants. The total number of entities is approximately 365 – larger than the number of facilities in this case but within a reasonable range for regulation.

C. Option C Pipelines

Much natural gas is transported through multiple pipelines before it reaches end users. Furthermore, natural gas often is transported by pipeline for injection into storage and then is withdrawn from storage and transported again at a later date. Thus, the cap-and-trade regulatory framework would need to address the potential for double coverage. A cap-and-trade point of regulation could be placed on pipelines by requiring pipelines to hold allowances for the embedded emissions of all natural gas they transport that was not delivered to their system from another regulated pipeline. Alternatively, a cap-and-trade program could require pipelines to hold allowances for the embedded emissions of all natural gas that they deliver to entities other than other regulated pipelines. Such requirements would not require tracking unique pipeline flows but would only require that pipelines track the volume of and immediate sources or recipients of their transported natural gas shipments.

Based on EIA data (Form 176), we estimate throughput of 11.3 Tcf for interstate pipelines and 6.9 Tcf for intrastate pipelines.[43] This accounts for 88 percent of end-use consumption of gas. The gas consumption that does not go through the pipelines includes direct deliveries of natural gas from producers to LDCs or large natural gas users in the production areas. It also includes lease and plant gas consumed in the production area and gas processing plants, respectively, before the gas reaches the pipeline system. Looking only at gas delivered to end-use consumers (i.e., excluding lease and plant gas), regulation at the pipelines would cover 94 percent of natural gas delivered to consumers. This option provides 87 percent coverage of coverable CO_2 emissions. EIA reports 60 interstate pipelines and 72 intrastate pipelines. While this paper uses 132 as an estimate of the number of pipeline entities, the actual number could be significantly lower because of ownership of multiple pipelines by the same entity. As noted above, some of these pipelines are co-owned by larger corporate entities. If regulated at the point of gas delivery to the pipeline or to consumers, the number of regulated facilities would be in the range of 27,750.

D. Option D Pipelines and LDCs

This option would regulate the final deliverers of natural gas to end users. Pipelines would need to hold allowances for the embedded emissions of all natural gas delivered to end users (but not for natural gas delivered to LDCs or other pipelines). Regulated LDCs would need to hold allowances for the embedded emissions of all natural gas delivered to their end users. There are approximately 1,200 LDCs, but the largest

150 account for 95 percent of gas throughput. This paper assumes only the largest 150 LDCs are regulated; however, the number of LDCs regulated could be increased to achieve a higher desired level of overall coverage of natural gas emissions. We assume that the pipeline delivery points are half of the total estimated delivery and receipt points.

This option would regulate the same pipeline entities/facilities as Option C above as well as the LDCs as included in Option F, below. At the entity level, this approach assumes that utility billing records would be accepted as sufficient for tracking LDCs' embedded emissions, so that only an additional 150 entities would require regulation. At the facility level, LDCs could be required to monitor thousands or tens of thousands of citygate delivery points where natural gas enters the LDCs' distribution networks thus increasing the number of regulated facilities under this option. Assuming a very conservative average of 20 delivery points per LDC, yields at least 3,000 regulated facilities.

This approach would cover 95 percent of the LDC consumption and essentially all of the large gas consumers served directly by pipelines. It would not cover direct emissions from natural gas production and processing (i.e. lease and plant fuel combustion and venting of formation CO_2 at processing plants). Overall, this is 93 percent of gas consumption. It would include 282 entities – the 132 pipelines and 150 large LDCs. If measurement at the facility level is required, it would include an estimated half of the 27,750 pipeline delivery and receipt points (since only pipeline deliveries are tracked) and 3,000 LDC citygate points for a total of 16,875 facilities.

E. Option E Large sources (>10,000 metric tons CO_2e per year)

This approach would include all facilities whose emissions of all GHGs exceed 10,000 metric tons CO_2e per year (10,000 TPY). We do not have a precise accounting of how much natural gas consumption is included at these facilities. As an estimate, we include:

- All natural gas consumed at power generation facilities
- 65 percent of natural gas consumed at industrial facilities (based on EIA and Census data)
- 80 percent of natural gas consumed in the pipeline and distribution sector (i.e. only the larger compressor drives are estimated to be above the emissions threshold)
- Plant gas (assuming that lease operations are mostly below the threshold)
- Non-energy CO_2 from processing plants

Altogether, this accounts for 54 percent of natural gas consumed for combustion. The residential/commercial gas consumption is the largest missing component, with the small industrial customers also a significant missing component. Counting both CO_2 from combustion of natural gas and non-energy CO_2, this option would account for 55 percent of coverable CO_2 emissions from the natural gas sector.

Note that this point-of-regulation option regulates large sources for their direct emissions whereas Options A through D regulated these sources through the embedded emissions in their fuel.

In estimating the number of regulated entities under this approach, we include only those facilities that would not be regulated due to emissions from some other fuel source or GHG (e.g., facilities that would already be regulated due to emissions from coal combustion are exluded). The Nicholas Institute has estimated that a 10,000 metric ton threshold for all GHG emissions from all sources would regulate slightly more than 8,000 facilities in the manufacturing sector.[44] Based on data from the EIA Manufacturing Energy Consumption Survey, we estimate that the increment attributable to natural gas combustion would be about 7,000 facilities.[45] This assumes some monitoring approach that would allow monitoring of an entire facility. If the approach were similar to that used in existing cap-and-trade programs, i.e., continuous emission monitors or equivalent on each stack, then some facilities might have dozens of monitoring locations.

There are also about 500 gas-only power plants that would be brought in under this approach. Gas-fired compressor drives on natural gas pipelines would also be included. We estimate that about half of the roughly 1,500 compressor stations would fall within the threshold for CO_2 emissions. We also include the 530 natural gas processing plants. This adds up to approximately 8,780 facilities regulated for their direct CO_2 emissions from natural gas combustion. We do not have accurate data on how many of these facilities are co-owned, but assuming a 70 percent diversity factor for industrial and power generation sources and counting all 132 of the interstate and intrastate pipelines gives an estimate of about 5,562 entities to be regulated under this approach.

F. Option F Large sources (>10,000 TPY) and LDCs

This option would be the same as the previous one except that it would include LDCs in order to cover emissions from small natural gas consumers that are excluded under Option E. Under a hybrid system, in which large emitters are regulated at the point of emission and smaller-volume consumers are covered via regulation of the LDCs, then the large emitters will need to be tracked by the LDCs as well as by the cap-and-trade system to ensure consistency and avoid double-counting of natural gas under the cap.

LDC entities and facilities regulated under this option are the same as under Option D.

Assuming that the cap-and-trade allowance cost will be passed through to LDCs' customers as higher prices, large-emitters that are directly regulated under the cap-and-trade program would need to be exempted from the allowance cost passed on by the LDCs since these large emitters would already have to hold allowances themselves to cover their own natural gas consumption. In addition, LDCs would need to subtract out their natural gas deliveries to directly regulated large emitters when calculating the quantity of natural gas for which the LDCs are obligated to hold allowances; otherwise, these natural gas deliveries to large emitters by LDCs would be double counted under the cap-and-trade program.[46]

This approach would also cover non-energy CO_2 emissions as described in Option E. In this case, the total coverage of combined CO_2 emissions would be 97 percent of the coverable CO_2 emissions for the natural gas sector. This option would require regulation of about 5,712 entities. Assuming that each regulated LDC is treated as a single facility for compliance purposes, this option would regulate about 8,930 facilities. If not, then assuming 20 city gates per LDC, regulation at the facility level would require monitoring 11,780 points or more.

V. Summary

Regulating GHG emissions from the natural gas sector poses a number of unique challenges to regulators designing a cap-and-trade system. Factors that must be carefully considered to ensure an efficient program include the selection of the appropriate point of regulation, the threshold facility/emission size for participation within the cap-and-trade system, and the inclusion or exclusion of fugitive emissions from the cap.

Table 5 provides a summary of the level of coverage of CO_2 emissions and the number of facilities and entities that would be regulated under the different point-of-regulation options. Figure 3 provides a visual summary of these options.

Table 5: Natural Gas Sector Coverage Summary

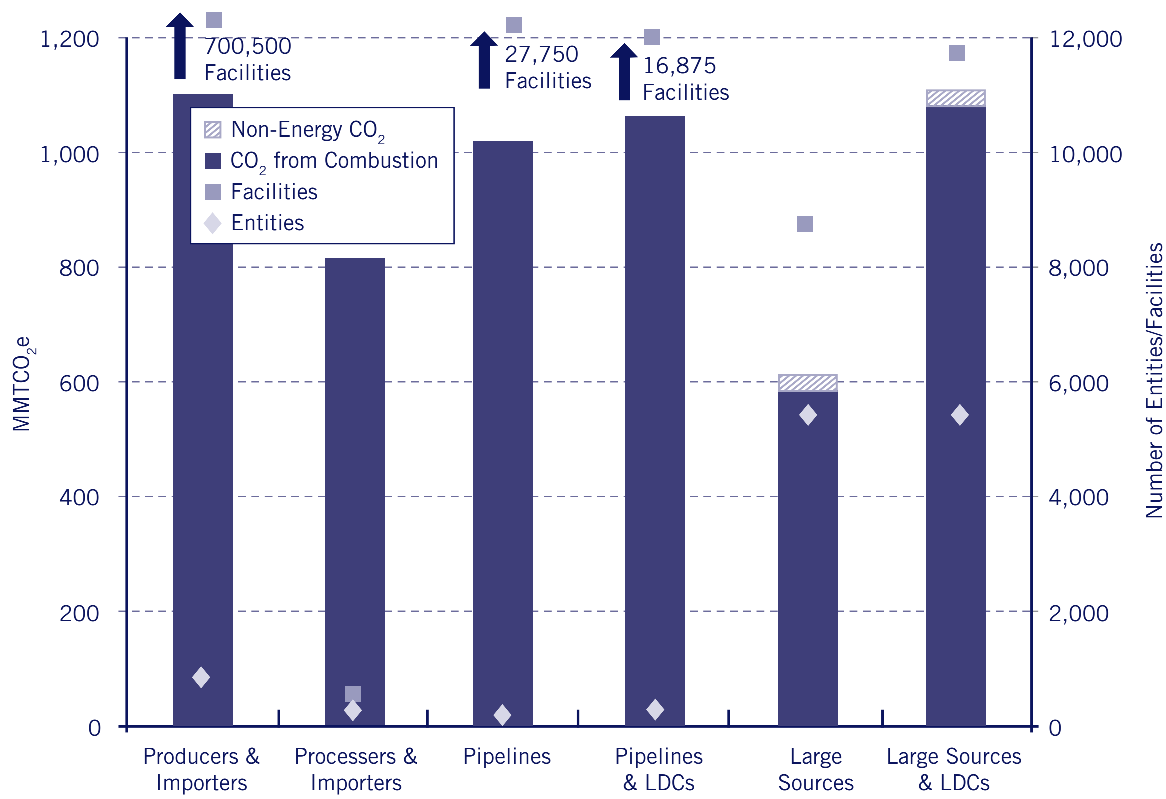
Point-of-Regulation Option	CO_2 from Gas Combustion		Non-Energy CO_2		Total CO_2 Coverage		Entities	Facilities
	$MMTCO_2e$	%	MMTCO2e	%	MMTCO2e	%		
Option A — Producers & Importers	1,106	96	0	0	1,106	94	825	700,500
Option B — Processors & Importers	825	71	0	0	825	70	365	566
Option C — Pipelines	1,025	88	0	0	1,025	87	132	27,750
Option D — Pipelines & LDCs	1,069	93	0	0	1,069	91	282	16,875
Option E — Large Sources	596	52	21	100	617	53	5,562	8,780
Option F — Large Sources & LDCs	1,092	95	21	100	1,113	95	5,712	11,780

One can see that the various point-of-regulation options present trade-offs in terms of coverage and the number of entities and facilities regulated. For example, point-of-regulation Option A (Producers & Importers) and Option F (Large Sources & LDCs) both have nearly complete coverage of the CO_2 from combustion of natural gas; however, these options require regulating widely divergent numbers of entities or facilities. Option F involves roughly seven times as many entities as does Option A, but Option A involves about 60 times as many facilities as does Option F.

The pipeline option (Option C) is in the middle in terms of coverage but may face challenges in terms of implementation given the complexity of accurately tracking pipeline flows. Option B (Processors & Importers) has the second lowest coverage because it does not cover gas that is not processed. Option E (Large Sources) has the lowest coverage due to the exclusion of the residential and commercial sectors and covers only 52 percent of coverable natural gas-related CO_2 emissions. In comparing Options E and F, one finds that a relatively small increase in the number of regulated entities or facilities provides a very large increase in coverage of CO_2 (from 53 percent to 95 percent).

The options that directly regulate emitters (Options E and F) have relatively large numbers of regulated entities and facilities, but numbers that are still within the range that could be accommodated within a cap-and-trade program. Option A has a reasonable number of regulated entities, but if regulation is required at the facility level, this option may be impractical depending upon the specific monitoring requirements (e.g., physical monitoring of each individual wellhead).

Figure 3: Gas Sector Coverage Summary



VI. Appendix

Table 6: GHG Emissions from Figure 2 ($MMTCO_2e$)

	CO_2 from Coal Combustion	CO_2 from Gas Combustion	CO_2 from Oil Combustion	Non-Energy Energy CO_2	Methane	N_2O	High GWP Gases	Total
Residential	1	238	89	0	3	2	13	345
Commercial	6	154	50	0	152	10	22	395
Industrial	122	389	351	266	227	30	30	1,415
Agricultural	0	0	44	0	199	283	0	526
Transportation	0	33	1,848	10	2	32	69	1,994
Power	1,936	341	80	0	1	11	13	2,382
	2,065	1,155	2,461	276	584	368	148	7,057

Endnotes

1. U.S. EPA. 2008. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006*. This EPA document is the source of all GHG emission figures in this report save for those related to lease and plant gas. See http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

2. Fugitive emissions generally come from fugitive equipment leaks, process venting, disposal of waste gas streams (e.g., by venting or flaring), and accidents and equipment failures. For more details on fugitive emissions, see Section 4.2 of the 2006 *IPCC Guidelines for National Greenhouse Gas Inventories.* Available at http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/ V2_4_Ch4_Fugitive_Emissions.pdf.

3. For a description of cap and trade, see *Climate Change 101: Cap and Trade* prepared by the Pew Center on Global Climate Change. Available at http://www.pewclimate.org/docUploads/Cap&Trade.pdf.

4. For a summary of cap-and-trade proposals see "Economy-Wide Cap & Trade Proposals in the 110th Congress" prepared by the Pew Center on Global Climate Change. Available at http://www.pewclimate.org/federal/analysis/congress/110/cap-trade-bills.

5. It is possible to augment cap-and-trade coverage of the natural gas sector with complementary policies that promote end-use efficiency.

6. "Entity" in this context is generally understood to mean a corporate entity (company), which may own or control multiple emitting facilities.

7. Pizer, William. 2007. *Assessing U.S. Climate Policy Options Issue Brief 4: Scope and Point of Regulation for Pricing Policies to Reduce Fossil Fuel CO_2 Emissions*. Resources for the Future. See http://www.rff.org/Publications/Pages/CPF_AssessingUSClimatePolicyOptions_IB4.aspx.

8. Based on 2006 gas consumption reported by the U.S. Energy Information Administration and the 2006 U.S. GHG Inventory prepared by EPA (*supra* note 1).

9. Carbon dioxide equivalent is a metric used to compare the amounts and effects of different greenhouse gases. It is determined by multiplying the emissions of a gas (by mass) by the gas's global warming potential (GWP), an index representing the combined effect of the length of time a given greenhouse gas remains in the atmosphere and its relative effectiveness in absorbing outgoing infrared radiation. CO_2 is the standard used to determine the GWPs of other gases. CO_2 has been assigned a 100-year GWP of 1 (i.e., the warming effect over a 100-year time frame relative to other gases). Methane (CH_4) has a 100-year GWP of 21.

10. U.S. EPA *supra* note 1.

11. There is little reliable data to separately quantify these emissions. For this document, both vented and fugitive emissions are subsequently referred to simply as fugitive emissions.

12. UNFCC "Global Warming Potentials" available at http://unfccc.int/ghg_data/items/3825.php.

13. CO_2 that is extracted along with natural gas from gas reservoirs is referred to as formation CO_2. See "Methane to Markets – Glossary" available at http://tinyurl.com/59w7mm.

14. National Energy Technology Laboratory. 2008. *Storing CO_2 with Enhanced Oil Recovery*. See Figure 4. Available at http://www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf.

15. Data sources: U.S. EPA *supra* note 1, Lease and plant fuel consumption from U.S. EIA Form EIA-895, "Monthly and Annual Quantity and Value of Natural Gas Production Report."

16. The flaring emissions are from the combustion of natural gas at the wellhead. Most flaring is believed to occur at oil production operations.

17. There also are 0.1 $MMTCO_2e$ of emissions during the transmission and storage process, less than 1 percent of the total natural gas system non-energy CO_2 emissions.

18. "US Producing Oil Wells Up Slightly." *World Oil Magazine*. February 2007.

19. EIA. 2008. "Number of Gas and Gas Condensate Wells." See http://tonto.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm.

20. EIA. 2008. "Natural Gas Gross Withdrawals and Production." See http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm

21. EIA. 2007. "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Report." Appendix E. See http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html.

22. Taxes and royalties are typically based on gas delivered to the pipeline, but are tracked back to wellhead production for the purpose of royalty reconciliation.

23. EIA *supra* note 21.

24. EIA *supra* note 21, Appendix A, "Operator Level Data".

25. EIA. 2008. "U.S. Natural Gas Imports by Point of Entry." See http://tonto.eia.doe.gov/dnav/ng/ng_move_poe1_a_EPG0_IRP_Mmcf_a.htm.

26. EIA. 2006. "Natural Gas Processing: The Crucial Link Between Natural Gas Production and its Transportation to Market." Table 1. See http://tinyurl.com/5u9kje. *Oil & Gas Journal* lists 566 NGL plants but does not report utilization. Some of these may be smaller or different kinds of plants than listed by EIA.

27. EIA. 2008. "U.S. Natural Gas Plant Processing." See http://tonto.eia.doe.gov/dnav/ng/ng_prod_pp_dcu_nus_a.htm.

28. EIA. 2008. "Natural Gas Gross Withdrawals and Production." See http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

29. EIA. 2008. "Natural Gas Summary." See http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_m.htm.

30. EIA defines "Lease Fuel" as "[n]atural gas used in well, field, and lease operations, such as gas used in drilling operations, heaters, dehydrators, and field compressors."

31. EIA defines "Plant Fuel" as "[n]atural gas used as fuel in natural gas processing plants."

32. American Gas Association (AGA) provides annual statistics on its website at http://www.aga.org/Research/statistics/annualstats.

33. AGA *supra* note 32.

34. Natural Gas Supply Association website, http://www.naturalgas.org/business/industry.asp#industry.

35. EIA. 2007. "EIA-176 Query System 2006." See http://www.eia.doe.gov/oil_gas/natural_gas/applications/eia176query.html.

36. EIA. 2008. "Number of Natural Gas Consumers." See http://tonto.eia.doe.gov/dnav/ng/ng_cons_num_dcu_nus_a.htm.

37. *Id.*

38. EIA. 2008. "Natural Gas Consumption by End Use." See http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

39. Natural Gas Supply Association website, http://www.naturalgas.org/overview/uses_industry.asp.

40. EIA *supra* note 38. These figures do not exactly match the sales figures taken from AGA for Table 2.

41. Natural Gas Supply Association *supra* note 34.

42. The Lieberman-Warner Climate Security Act of 2008 (S.3036) exempted use of fossil fuels as feedstocks via a feedstock credit under the cap-and-trade program. See S.3036 Sec. 1202(e).

43. EIA *supra* note 35.

44. Nicholas Institute. 2007. *Size Thresholds for Greenhouse Gas Regulation: Who Would be Affected by a 10,000-ton CO_2 Emissions Rule?* NI PB 07-02. See http://www.nicholas.duke.edu/institute/10Kton.pdf.

45. EIA. 2008. "Manufacturing Energy Consumption Survey." See http://www.eia.doe.gov/emeu/mecs/contents.html.

46. One approach to resolve this issue would be to rely on large-emitters who are directly regulated under the cap-and-trade program to notify their LDC suppliers that they need to be exempted from the LDCs' compliance obligation with a requirement that such large emitters provide official certification that they are already directly regulated. Alternatively, the appropriate regulatory authority could provide a list of entities and/or facilities that are directly regulated as large emitters to the LDCs for the LDCs to compare against their customer list to determine which of their customers are already directly regulated as large emitters.

This paper provides an overview of the different point-of-regulation options for covering greenhouse gas emissions from natural gas under a cap-and-trade program. The Pew Center on Global Climate Change was established in 1998 in order to bring a cooperative approach to the debate on global climate change. The Pew Center continues to inform the debate by publishing reports in the areas of policy (domestic and international), economics, environment, and solutions.

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