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June 19, 2014

Via Email
Original via Mail

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C.
V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Energy Utilities[1] (FEU)

2014 Long Term Resource Plan (the Application)

Response to the B.C. Sustainable Energy Association and the Sierra Club British Columbia (BCSEA) Information Request (IR) No. 1

On March 25, 2014, the FEU filed the Application as referenced above. In accordance with the British Columbia Utilities Commission Order G-56-14 setting out the Regulatory Timetable for review of the Application, the FEU respectfully submit the attached response to BCSEA IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)\

[1] comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

1.0 Topic: Pacific Northwest

Reference: Exhibit B-1, p.26

"Energy consultant ICF International predicts that an additional 2,500 MW of gas-turbine capacity will be needed by 2025 to firm the PNW's wind generation and that nearly six percent of the regional's [sic] total natural gas demand will be for that purpose.28 The growing use of renewable, intermittent resources may change the way that the region's gas infrastructure will be called upon to meet the region's future energy needs – a possibility for which the FEU must be prepared."
http://www.pnucc.org/sites/default/files/BPA%20Power-Natural%20Gas%20Whitepaper%208-24-12.pdf

1.1 Please confirm that "PNW" with reference to wind generation in the first quoted sentence refers to the U.S. Pacific Northwest. If not confirmed, please explain.

Response:

The FEU confirm that the statistical information quoted in the preamble is in reference to the U.S. Pacific Northwest; however, both natural gas and electricity are traded and flow throughout both Canada and the U.S. Pacific Northwest so that the implications of the information – that the growing use of intermittent sources of electricity may impact the natural gas supply infrastructure throughout the region - includes B.C.

1.2 What is the "region" referred in the phrase "nearly six percent of the regional's [sic] total natural gas demand" in the first quoted sentence? Does it include B.C.?

Response:

Please refer to the response to BCSEA IR 1.1.1.

1.3 In the second quoted sentence, what is the "region" referred to in the phrase "the region's gas infrastructure"? Does the reference include B.C.'s gas infrastructure?

Response:

Yes. Please refer to the response to BCSEA IR 1.1.1.

1.3.1 Please explain how the term 'B.C.'s gas infrastructure' differs from the 'FEU gas infrastructure'.

Response:

The Term 'FEU's Infrastructure' refers to the gas delivery infrastructure owned and operated by the FEU, while the term 'B.C.'s gas infrastructure' refers to all natural gas transportation infrastructure in the Province. Spectra Energy and TransCanada Pipelines are two examples of companies that also own gas transportation infrastructure in B.C. The FEU contract for gas transportation on other third party pipelines in B.C. and throughout the PNW (Canada and the U.S.), and provide transportation service to other third parties in the PNW on a portion of their gas infrastructure. Market dynamics and movement of energy around the entire PNW has implications for the FEU and their customers.

1.4 Does the second quoted sentence mean that the FEU must be prepared for the possibility that the US Pacific Northwest gas infrastructure will be called upon to meet the US Pacific Northwest region's future energy need for gas to firm up wind generation in the US Pacific Northwest?

Response:

Yes, the firming of wind generation is one example of changing market dynamics that could impact the region's natural gas infrastructure. Since gas infrastructure in the PNW region (Canada and the U.S.) is interconnected, additional gas demand from anywhere throughout the PNW might ultimately affect the planning of gas supply for all gas purchasers in the region, including the FEU.

Utilities in the U.S. PNW region currently source a portion of their gas from Northern B.C. and Alberta and deliver this gas to their service areas through B.C.'s pipelines. Increases in natural gas demand in the U.S. PNW region would potentially increase gas flow on the pipelines that the FEU rely upon as well, which would increase regional competition for gas supply, storage and pipeline capacities. Increased gas flow in the PNW region may also require expansion of infrastructure in B.C., including in the FEU's operating regions, in the near future.

To ensure cost effective and secure supply for the FEU's customers, the FEU continuously monitor gas and power market developments in the PNW and their potential impact on regional gas infrastructure. This enables the FEU to be proactive in contracting for pipeline, storage and commodity resources as defined within the FEU's Annual Contracting Plan (ACP) and developing regional infrastructure when warranted.

1.4.1 If not, please explain what is meant.

Response:

Please refer to the response to BCSEA IR 1.1.4.

1.4.2 In any event, please explain (a) how FEU would be affected by the materialization of this possibility and (b) how FEU proposes to be prepared for it.

Response:

Please refer to the response to BCSEA IR 1.1.4.

2.0 Topic: Pacific Northwest

Reference: Exhibit B-1, p.26

"The NWGA [Northwest Gas Association] also advocates policies to promote the direct use of natural gas since gas is seen as a pillar of the region's electricity resource strategy to reduce the use of coal-fired generation and allows integration of a growing fleet of intermittent renewable resources.[31]"

2.1 Please confirm that the quoted statement refers to the US Pacific Northwest region. Alternatively, please explain how the reference to the reduction of the use of coal-fired generation applies to B.C.

Response:

Since B.C. does not currently have any coal-fired generation plants, the NWGA statement refers to the U.S. Pacific Northwest region. Major coal-fired generation plants in the U.S. PNW region include the Boardman and Centralia generation plants, which are both expected to be retired beginning in 2020 and replaced with natural gas generation and renewable energy sources.

Nevertheless, it is important to note that both gas and electricity infrastructure in the PNW region (Canada and the U.S.) is interconnected. Therefore, additional natural gas demand in the U.S. PNW region would also affect demand on B.C.'s supply infrastructure and therefore gas supply and infrastructure planning for the FEU, as described in the response to BCSEA IR 1.1.4.

3.0 Topic: Pacific Northwest

Reference: Exhibit B-1, p.26

"As in B.C., natural gas is gaining traction as an alternative transportation fuel and the region will look to retain and secure access to abundant and diverse sources of gas supply while ensuring that that the associated transmission, storage and distribution infrastructure can grow as necessary.[32] An anticipated increase in natural gas demand within the PNW region will provide B.C. with an opportunity to leverage its new natural gas supply resources to fulfill this anticipated market demand."

3.1 Please confirm that "the region" in the first quoted sentence and "the PNW region" in the second quoted sentence refer to the US Pacific Northwest. Alternatively, please explain.

Response:

The entire quoted statement above refers to the PNW region as defined in the 2014 LTRP, page 5 of Appendix G. Gas infrastructure in the PNW region (including B.C.) is interconnected and operates together as a whole, as described in the response to BCSEA IR 1.1.4.

3.2 With reference to the second quoted sentence, what does "leverage" mean? Does it mean 'sell'? What are the implications for FEU and its long-term resource planning?

Response:

"Leverage" refers to an opportunity to utilize today's abundance of natural gas supply in B.C. to serve anticipated market demand throughout the PNW region. It could mean "to sell" in the context of selling natural gas or LNG.

To ensure cost effective and secure supply for the FEU's customers, the FEU continuously monitor gas demand and shared infrastructure in the PNW and contract and plan for supply resources according to the FEU's gas supply Annual Contracting Plan (ACP). Please refer to the response to BCSEA IR 1.1.4.

4.0 Topic: BC Policy

Reference: Exhibit B-1, p.28

With reference to the B.C. *Clean Energy Act*, FEU states:

"Natural gas, electricity and hydrogen are thus encouraged as vehicle fuel alternatives to higher emitting fuels such as gasoline and diesel. Nevertheless, the *CEA* does not promote the use of natural gas over electricity where gas is more efficient such as in thermal applications; in fact, the *CEA* defines "demand-side measure" in B.C. to specifically exclude any fuel switching activities that lead to an increase in GHG emissions."

4.1 Does FEU agree that the B.C. energy policy can be characterized as discouraging the use of natural gas in substitution for lower-carbon alternatives and only encouraging the use of natural gas in substitution for higher-carbon fuels?

Response:

No, the FEU do not agree with this statement. Energy policy in B.C. can be characterized as discouraging the use of natural gas in substitution for lower carbon alternatives in certain situations. However, the FEU do not agree that B.C. energy policy only encourages the use of natural gas in substitution for higher-carbon fuels. As outlined in the LTRP Appendix A-5, B.C.'s Energy Objectives Regulation modifies section 2(c) of the *Clean Energy Act* to allow LNG export facilities to generate electricity from natural gas. Therefore, LNG export facilities are enabled and encouraged to use natural gas for electricity generation at the same time that they are able to use B.C.'s clean or renewable energy sources to serve their large electricity requirements. The FEU understand that this policy change was made as a means to keep B.C.'s electricity rates low, protect residential ratepayers and maintain reasonable energy cost for industry. In this situation, BC Energy policy encourages the use of natural gas over a lower carbon alternative.

5.0 Topic: BC Policy

Reference: Exhibit B-1, p.28

"Excluding electricity-to-gas fuel switching as a demand-side measure may cloud customer and public perception of natural gas as an efficient fuel."

5.1 Does FEU agree that excluding electricity-to-gas fuel switching as a demand-side measure in B.C. clarifies customer and public perception that natural gas is more carbon-intensive than electricity in B.C.?

Response:

The FEU are not aware of any research on whether or not this exclusion has influenced customer and public perception on the carbon intensity of natural gas in BC. GHG emissions are not are not constrained by political boundaries, actions taken in BC affect those in other jurisdictions. The FEU believe that limiting the consideration of carbon emissions from energy use within political boundaries can result in sub-optimal decisions on energy choice with regard to both overall carbon emissions and energy costs.

6.0 Topic: BC Policy

Reference: Exhibit B-1, p.28

"This, combined with heavy government and media emphasis on B.C.'s electricity as a clean, renewable energy source, may contribute to customer and stakeholder confusion regarding the role of natural gas."

6.1 Does FEU agree that in B.C. electricity is a generally a clean or renewable energy source, that natural gas is more carbon-intensive than electricity, and that natural gas along with electricity and hydrogen are preferable alternatives to higher-carbon emitting fuels such as gasoline and diesel?

Response:

The FEU believe that electricity generated in B.C. can be considered a relatively clean or renewable energy source. However, B.C. trades electricity with neighbouring jurisdictions and imports electricity that is produced from coal-fired power generation that is more carbon intensive than electricity produced from natural gas or direct use of natural gas. Therefore, from both and economic and GHG perspective, using natural gas for efficient end use heating frees up clean electricity to be sold in the market displacing coal (less efficient) fired electrical generation. This has the impact of both reducing energy costs for consumers in BC while at the same time reducing GHG emissions overall.

7.0 Topic: BC Policy

Reference: Exhibit B-1, pp.28, 29

"However in the last few years, the government has begun to actively promote the role that natural gas can play in both economic development and in reducing emissions." [p.28]

"These policy developments present an opportunity for the FEU to catalyze the marketplace for compressed natural gas (CNG) and liquefied natural gas (LNG) as a main fuel for return-to-base vehicle fleets." [p.29]

7.1 Please confirm that encouraging CNG and LNG as a main fuel for return-to-base vehicle fleets traditionally fueled by diesel is consistent with the B.C. energy objective to reduce BC GHG emissions.

Response:

Confirmed.

8.0 Topic: BC Policy

Reference: Exhibit B-1, pp.29, 30

"On February 3, 2012, the Government of B.C. unveiled its Natural Gas Strategy and LNG Strategy (provided in Appendix A-6), which outline a vision to become an international leader in LNG development and recognize the role of natural gas as a transition fuel to a low carbon global economy." [p.29, underline added]

"...the Government's rationale that natural gas can be used to reduce global GHG emissions,..." [p.30]

8.1 Does FEU have any evidence to support the concept of "natural gas as a transition fuel to a low carbon global economy"? If so please provide it.

Response:

Since GHG emissions transcend political and geographical boundaries, steps taken to reduce GHG emissions in any one place or jurisdiction – in any sector and targeting reductions of any of the gases known to cause climate change – contribute to reducing GHG emissions globally.

Coal, petroleum-based fuels and natural gas are all fossil fuels that are used extensively throughout the global economy. Natural gas is the lowest carbon fossil fuel; therefore, natural gas can be used as a transition fuel to a low carbon global economy where it is used in applications to switch away from higher-carbon fuels.

On page 4 of Exhibit A2-1, the NWGA 2014 Gas Outlook states, "energy-related greenhouse gas emissions in the U.S. have been reduced to a level not seen in more than a decade, in part because of increased substitution of natural gas for coal in power generation." In this example, natural gas has played a role in reducing global GHG emissions by reducing the GHG emissions from U.S. power generation.

8.2 Does FEU have any evidence to support the proposition that "natural gas can be used to reduce global GHG emissions"? If so, please provide it.

Response:

Please refer to the response to BCSEA IR 1.8.1.

8.3 Does FEU have any evidence to support a conclusion that the export of LNG from B.C. would on balance displace more GHG emissions than would be produced by the end use of such natural gas? If so please provide it.

Response:

This question is not in scope for the review this LTRP proceeding, however, the FEU provide the following information in an effort to be responsive.

Determining whether LNG exports from B.C. would on balance displace more GHG emissions than would be otherwise produced at the end use would require knowledge of the applications for which the exported LNG will be used. However, the FEU have no knowledge of such information and are therefore not able to provide such evidence.

Natural gas remains the lowest carbon fossil fuel and measures taken to switch users from higher carbon fuels to lower carbon fuels including natural gas contribute to reducing GHG emissions. Please refer to the response to BCSEA IR 1.8.1 for additional information on how natural gas can be used as a transition fuel to a low carbon global economy where it is used in applications to switch away from higher-carbon fuels.

8.4 Please comment on the proposition that the concept of “natural gas as a transition fuel to a low carbon global economy” too general and is no more useful than the concept that ‘natural gas is a fossil fuel and its use never contributes to reducing GHG emissions.’

Response:

The FEU do not have any comment on this statement.

9.0 Topic: BC Policy

Reference: Exhibit B-1, p.29

"B.C.'s LNG Strategy commits the province to having three LNG facilities in operation by 2020 and represents an attempt to create a new industry that is intended to bring significant job-creation and economic benefits to the province."

9.1 Please confirm that, in this context, "LNG facilities" means facilities that would liquefy natural gas for the purpose of export.

<u>Response:</u>

The FEU agree with this interpretation.

9.2 Would FEU agree that the B.C. LNG Strategy' 'commitment' to "having three LNG facilities in operation by 2020" is an aspirational statement not a firm commitment that should be counted on for long-term planning purposes?

<u>Response:</u>

The FEU cannot comment on whether the BC Government intends this statement as a firm commitment or an aspirational statement.

10.0 Topic: BC Policy

Reference: Exhibit B-1, p.29, p.30

"Critical priorities that guide the strategies include: maintaining B.C.'s competitiveness in global LNG markets; promoting natural gas as a transportation fuel; developing new markets for gas-related industries such as a gas-to-liquids, methanol and fertilizer production; and ensuring a reliable supply, available infrastructure and effective royalty regime to encourage investment in B.C.'s natural gas sector." [p.29]

"The FEU are well-positioned to assist in meeting the government's objectives in B.C.'s Natural Gas and LNG Strategies." [p.30]

10.1 For each of the stated priorities, please describe the direct implications for FEU's long-term resource planning and state how FEU's 2014 LTRP assists in meeting the objectives.

Response:

The following table provides examples of the implications of the stated priorities for FEU's 2014 LTRP. This should not be considered an exhaustive list.

Stated Priority	Direct Implication for FEU's Long Term Resource Planning	How the 2014 LTRP Assists in Meeting the Objectives
Maintaining B.C.'s competitiveness in global LNG markets	The FEU must consider the potential for new industrial demand within the Companies' service territory, and also how gas demand for LNG development may increase the competition for supply resources and affect the movement of natural gas throughout the PNW region.	Section 3.3.9 and the system capacity analysis in Section 5.1 indicate how the FEU examine the potential impact of new industrial customers. In addition, the alternative future scenario discussion in Section 3.3.4 of the LTRP considers the potential for constrained gas supply. Section 6 discusses how the FEU plan to acquire a reliable and cost-effective gas supply given marketplace developments that may impact traditional regional gas flows and regional supply and demand.

Stated Priority	Direct Implication for FEU's Long Term Resource Planning	How the 2014 LTRP Assists in Meeting the Objectives
Promoting natural gas as a transportation fuel	The FEU must plan to meet anticipated market demand for natural gas as a transportation fuel; in addition, the FEU must examine the impact of adding NGT load on customer rates.	Section 2.3.1 and Appendix A-8 outline the FEU's initiatives to promote natural gas as a transportation fuel. Section 3.3.7 identifies the forecast annual demand for NGT and Section 5.1 shows the potential system impacts of NGT demand. Section 8 examines the contribution of NGT initiatives to the province's GHG reduction goals in addition to a directional rate impact analysis that includes NGT initiatives as a demand-side activity that assists in building load and optimizing use of the distribution system.
Developing new markets for gas-related industries such as gas-to-liquids, methanol and fertilizer production	The FEU must consider the potential for new industrial demand within the Companies' service territory and also how additional gas demand from these new markets may affect the movement of natural gas throughout the PNW region.	Section 3.3.9 and the system capacity analysis in Section 5.1 indicate how the FEU examine the potential impact of new industrial customers. Section 6 discusses how the FEU plan to acquire a reliable and cost-effective gas supply given marketplace developments that may impact traditional regional gas flows and regional supply and demand.
Ensuring a reliable supply, available infrastructure and effective royalty regime to encourage investment in B.C.'s natural gas sector	The FEU must consider the potential for new industrial demand within the Companies' service territory, particularly since the FEU's infrastructure can also play a key role in unlocking new markets to encourage investment in B.C.'s natural gas sector.	Section 3.3.9 and the system capacity analysis in Section 5.1 indicate how the FEU examine the potential impact of new industrial customers and additional demand on the distribution system.

11.0 Topic: BC Policy

Reference: Exhibit B-1, p.30

"Using the Government's rationale that natural gas can be used to reduce global GHG emissions, the Companies believe the efficient use of natural gas for heating applications in B.C. can provide a similar benefit for global emissions when displaced electricity load results in clean electricity supply available for export to offset coal and gas fired generation in neighbouring jurisdictions, or reduces the need to import electricity from neighbouring jurisdictions.[34]

[34]This assertion is supported by comprehensive analysis conducted by the Center for Climate and Energy Solutions(C2ES) in its June 2013 report, "Leveraging Natural Gas to Reduce GHG Emissions." http://www.c2es.org/publications/leveraging-natural-gas-reduce-greenhouse-gas-emissions"

11.1 Exactly what assertion does FEU say is supported by the C2ES report? Which portion of the C2ES report is FEU citing?

Response:

The FEU cite one of the report's primary conclusions that since combusting natural gas yields fewer greenhouse gas emissions than coal or petroleum, the expanded use of natural gas offers significant opportunities to help address global GHG emissions (C2ES, pg. vii).

The C2ES report supports the FEU's assertion that using natural gas directly in heating applications in B.C. can provide benefit for global GHG emission reductions when this avoided electricity load results in clean electricity supply available to displace more carbon-intensive electricity generation in neighbouring jurisdictions. Electricity is a commodity that B.C. trades with other neighbouring jurisdictions including Alberta and U.S. PNW states, where coal and natural gas play a prominent role in electricity generation. As such, the FEU assert that using natural gas directly for heating applications in B.C. instead of using clean electricity for those purposes, could offer an opportunity to reduce GHG emissions in other jurisdictions when this clean electricity is made available for export.

11.2 Please confirm that the scope and focus of the C2ES report is on the expanded use of natural gas in the United States primarily as a replacement for coal and petroleum.

Response:

The FEU confirm that the scope and focus of the C2ES report is on the expanded use of natural gas in the United States primarily as a replacement for coal and petroleum. However, GHG emissions and their reduction are global issues and the report's key focus on using a lower-carbon fossil fuel to replace higher-carbon fossil fuels remains a universal concept. The physical location of where the fuel switching activity takes place is irrelevant as GHG emissions transcend political and geographical boundaries. Please refer to the response to BCSEA IR 1.8.1 for additional information on how reducing GHG reductions contribute to a low carbon global economy.

11.3 Please confirm that the C2ES report does not purport to address the concept that "natural gas can be used to reduce global GHG emissions" except to the extent that U.S. GHG emissions are a component of global GHG emissions.

Response:

The C2ES report purports to "explore the opportunities and challenges in leveraging the natural gas boom to achieve further reductions in U.S. greenhouse gas emissions" (pg. vii). As noted in response to BCSEA IR 1.11.2, GHG emissions are a global issue and the C2ES report focuses on the universal concept of using a lower-carbon fossil fuel to replace higher-carbon fossil fuels.

11.4 With reference to the phrases "the Companies believe the efficient use of natural gas for heating applications in B.C." and "displaced electricity load," is FEU addressing in this sentence the intentional substitution of natural gas for electricity for heating applications in B.C.?

Response:

Confirmed. Please refer to the response to BCSEA IR 1.11.1 for a description of how switching from electricity to natural gas in heating applications in B.C. could reduce global GHG emissions.

11.4.1 If not, please explain.

Response:

Please refer to the responses to BCSEA IRs 1.11.4 and 1.11.4.2.

11.4.2 If so, please confirm that the carbon intensity of electricity in B.C. is substantially lower than the carbon intensity of the electricity referred to by the authors of the C2ES report when they state in Table ES-1 “onsite natural gas use has the potential to provide lower-emission energy compared with oil or propane and electricity in most parts of the country [U.S.]”

Response:

Table ES-1 does not provide a factor for the carbon intensity of electricity with which to compare the carbon intensity of electricity in B.C., however, it is likely that the carbon intensity of electricity in B.C. is lower than the carbon intensity of the electricity referred to in the C2ES report in Table ES-1. As noted in response to BCSEA IR 1.11.3, the C2ES report focuses on the universal concept of using a lower-carbon fossil fuel to replace higher-carbon fossil fuels. The FEU also believe that preserving clean electricity for its highest and best use, which the FEU would argue is not for heating and hot water, can also contribute to the reduction of GHG emissions when it is instead made available to offset higher GHG intensive generation in neighbouring jurisdictions. Please refer to the response to BCSEA IR 1.11.1 for a description of how switching from electricity to natural gas in heating applications in B.C. could reduce global GHG emissions.

11.5 What does FEU mean when it states “...when displaced electricity load results in clean electricity supply available for export to offset coal and gas fired generation in neighbouring jurisdictions”?

Response:

Please refer to the responses to BCSEA IR 1.11.1 and 1.11.4.2.

11.5.1 Is FEU asserting that the use of natural gas through the FEU system to displace electricity load in B.C. results in clean electricity supply available for export to offset coal and gas fired generation in neighbouring jurisdictions"?

Response:

Yes. Please refer to the responses to BCSEA IR 1.11.1 and 1.11.4.2.

11.5.2 If not, please explain what FEU means.

Response:

Please refer to the response to BCSEA IR 1.11.5.1.

11.5.3 Is FEU referring to clean electricity supply available for export by BC Hydro, by FortisBC Inc. (electric), or both?

Response:

The FEU are referring to clean electricity that is generated in B.C. in general, regardless of the generating entity.

11.5.4 What is FEU's understanding regarding whether BC Hydro's approved 2013 Integrated Resource Plan (IRP) contemplates electricity exports for the purpose of displacing higher-carbon generation sources?

Response:

The FEU are aware that Section 5.8 of BC Hydro's 2013 Integrated Resource Plan (IRP) assesses market opportunities to develop new, additional clean or renewable resources primarily for the purposes of exporting electricity to the U.S. in the RPS / Renewable Compliance Market. The FEU understand that for planning purposes, BC Hydro's IRP electricity export analysis is driven by the *Clean Energy Act* objective to be a net exporter of electricity. BC Hydro's IRP analysis does not examine opportunities for export that arise through the sale of surplus capability in the BC Hydro system associated with acquiring resources to meet domestic load self-sufficiency requirements. Since the self-sufficiency requirements are based on average water conditions the quantities of electricity that are available for export by BC Hydro can vary based on actual conditions between net imports in below average water years to net exports in above average water years. Thus optimization of exports within the self-sufficiency requirements involves more of a short term planning and management approach.

11.5.5 Is FEU making this proposition as a short-term effect (i.e., in the operational time period) or as a long-term planning factor?

Response:

The quoted statement simply indicates that given the B.C. Government's position, the FEU believe that natural gas could also be used in direct applications in B.C. to reduce GHG emissions in other jurisdictions (as well as locally). The FEU do not consider this to be a short term effect only; opportunities to pursue these emissions benefits will persist into the longer term planning horizon. Please also refer to the response to BCSEA IR 1.11.1.

11.5.6 Please provide whatever information and analysis FEU relies on to support the contention that the use of natural gas in substitution for electricity in B.C. for heating applications, bearing in mind hourly and seasonal heating load, does or would result in fewer GHG emissions than the GHG emissions that would be avoided by sale of the displaced B.C. electricity into U.S. markets thereby displacing marginal generation sources at those times.

Response:

Please refer to the response to BCSEA IR 1.11.5.5.

11.6 Regarding "or reduces the need to import electricity from neighbouring jurisdictions," is FEU referring to FBC or BC Hydro or both? To what neighbouring jurisdictions is FEU referring?

Response:

Please refer to the responses to BCSEA IRs 1.11.5.5 and 1.11.1. The statement is made regarding electricity in general.

11.7 What is FEU's understanding regarding whether BC Hydro is a net importer of electricity for planning purposes?

Response:

Please refer to the response to BCSEA IR 1.11.5.4.

11.8 With reference to FEU's phrase, "Using the Government's rationale that natural gas can be used to reduce global GHG emissions," what is FEU's understanding of the meaning of "can be used"? Does FEU agree that the mere use of natural gas does not automatically reduce global GHG emissions? Please distinguish FEU's view and the Government's view as FEU understands it, if necessary.

Response:

Please refer to the responses to BCSEA IRs 1.11.1, 1.4.2 and 1.8.1 for further discussion of the way that the FEU believe that natural gas can help to reduce GHG emissions. The discussion that is referred to in the preamble presents the FEU's view as indicated by the phrase "the Companies believe…" as contained in the excerpt.

11.9 Is it FEU's position that current B.C. government policy applicable to the Commission's consideration of the FEU LTRP is that GHG emissions should be analyzed on a global basis and not on a B.C. basis?

Response:

From both an operational and resource planning perspective, the FEU adhere to relevant B.C. government policy and expect the Commission to consider the 2014 LTRP within the provincial context. The quoted statement simply applies the line of reasoning for an existing B.C. policy (B.C. Energy Objectives Regulation) to highlight another policy option that the B.C. government could potentially consider to reduce global GHG emissions. Please refer to the response to BCSEA IR 1.11.1 for additional information on how switching from electricity to natural gas in heating applications in B.C. could reduce global GHG emissions.

11.10 Please confirm that the C2ES report concludes in part:

> "Substitution of natural gas for other fossil fuels cannot be the sole basis for long-term U.S. efforts to address climate change because natural gas is a fossil fuel and its combustion emits greenhouse gases. To avoid dangerous climate change, greater reductions will be necessary than natural gas alone can provide. Ensuring that low-carbon investment dramatically expands must be a priority."

Response:

Confirmed (C2ES, pg. vii).

11.10.1 In FEU's view does this conclusion apply to B.C.?

Response:

As stated in response to BCSEA IR 1.11.2, the focus of the C2ES report is on the expanded use of natural gas in the United States primarily as a replacement for coal and petroleum. Under the existing legislative framework, this conclusion would not apply to BC.

11.11 Please confirm that the C2ES report concludes in part:

"Along with substituting natural gas for other fossil fuels, direct releases of methane into the atmosphere must be minimized. It is important to better understand and more accurately measure the greenhouse gas emissions from natural gas production and use in order to achieve emissions reductions along the entire natural gas value chain."

Response:

Confirmed (C2ES, pg. vii).

The FEU also note that the report concludes the following, in part:

"Natural gas is transported from areas of production to final consumers through networks of gathering pipelines, transmission pipelines, and distribution pipelines. These extensive networks are necessary to provide opportunities for low-emission end uses of natural gas. Given the recent surge in natural gas supply, the new source regions, and new uses, infrastructure must rapidly adapt. Gathering pipelines must be brought to more points of production, including areas where associated gas can be captured for use. Transmission pipelines must be expanded to ensure adequate supply can reach new regions of the country. Distribution pipeline networks must be built out to serve more manufacturing facilities, homes, and businesses. Increased policy support and innovative funding, particularly for distribution pipelines, are needed to support the rapid deployment of this infrastructure."

11.11.1 In FEU's view does this conclusion apply to B.C.?

Response:

The FEU believe that the both the conclusion quoted in the preamble and the conclusion quoted in the response of BCSEA IR 1.11.11 may apply to B.C.'s context.

11.12 Please file a copy of the C2ES report.

Response:

Please refer to Attachment 11.12 for a copy of the C2ES report.

12.0 Topic: BC Policy

Reference: Exhibit B-1, s 2.2.3.3, Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR), page 30

"As part of the province's strategy to encourage the use of natural gas as a transportation fuel, on May 14, 2012, policymakers introduced the Greenhouse Gas Reduction (Clean Energy) Regulation through a "prescribed undertaking" under sections 18 and 35(n) of the CEA. The regulation authorizes a utility to spend up to $104.5 million in natural gas transportation program funding including:" [p. 30]

12.1 Please confirm that, for the purposes of the CEA and the Greenhouse Gas Reduction (Clean Energy) regulation (GGRR), a "prescribed undertaking" means "a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia."

<u>Response:</u>

The FEU confirm that a "prescribed undertaking" pursuant to Section 18 of the *CEA*, which provides the statutory basis for the GGRR, is defined as "a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing GHG emissions in British Columbia."

12.2 Please confirm that the GGRR applies specifically to uses of fuel for transportation and not for other purposes.

<u>Response:</u>

The prescribed undertakings outlined in the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) apply specifically to projects, programs, contracts or expenditures in the transportation sector. The GGRR is not limited specifically to fuel use as the regulation enables the FEU to provide capped expenditures on grants or zero-interest loans for eligible vehicle purchases, to build, own and operate compressed natural gas (CNG) or liquefied natural gas (LNG) fuelling stations, and to implement safety practices or improve maintenance facilities for operating and maintaining an eligible vehicle.

12.3 What responsibility does FEU have to determine or verify whether a project, program, contract or expenditure undertaken pursuant to the GGRR does in fact reduce greenhouse gas emissions (GHG) in British Columbia?

Response:

Any initiative under consideration pursuant to the GGRR includes examination of GHG emissions reductions.

13.0 Topic: Natural Gas for Transportation

Reference: Exhibit B-1, s 2.2.3.3, Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR), page 30

13.1 In relation to FEU's activities undertaken under the GGRR and FEU's NGT program, please describe the extent to which FEU relies on government to determine what actions or technologies would reduce GHGs, in BC or globally, and by how much.

Response:

This series of questions are not in scope for the review this LTRP proceeding, however, the FEU provide the following information in an effort to be responsive.

The FEU's main objective is to provide products and services safely and reliably in a cost effective manner, and the resulting GHG emission reduction is an additional benefit resulting from this activity. The BC Provincial Government enacted the GGRR, which is designed to reduce GHG emissions by enabling the adoption of natural gas as a transportation fuel. However, the FEU have not relied on government to determine the technologies which would reduce GHG's in BC.

13.2 Please describe the extent to which FEU relies on government to determine the methods by which FEU analyses the GHG emissions consequences of FEU activities under the GGRR and the FEU NGT program.

Response:

The FEU rely on carbon intensity values that are verified through the GHGenius model. GHGenius is the designated model used by both the provincial and federal governments to determine GHG emissions. The FEU have measured the reduction in GHG emissions on a comparative basis using the metric of carbon dioxide equivalent (CO2e). That is, it measures the amount of CO2e emissions generated by the fuel currently being consumed and compares that to the amount of CO2e emissions generated by a CNG or LNG fueled vehicle based on accepted carbon intensity values.

The FEU are obligated to report semi-annually with the BC Ministry of Energy and Mines with respect to its NGT Program operated under the GGRR. As part of this reporting, the FEU detail the quantity of GHG emissions that it has displaced as a result of increased natural gas use, and what it expects to displace over the next several years using the methodology described above. It would then be up to the government to determine if the information and methodologies contained within the report are reasonable.

13.3 Section 18 of the Clean Energy Act defines "prescribed undertaking" as being "the purpose of reducing greenhouse gas emissions in British Columbia." How does FEU define "reducing greenhouse gas emissions in British Columbia"?

Response:

The FEU define "reducing greenhouse gas emissions in British Columbia" as engaging in any action that would reduce the total amount of GHG emissions. An example of this is the FEU's NGT program, which provides incentive funding for fleet operators to convert to natural gas fueled vehicles.

Please refer to the response to BCSEA IR 1.13.2 for a description of FEU's methodology for calculating GHG emission reductions.

13.4 Please describe the analysis FEU uses to determine whether an NGT project, program, contract or expenditure that it undertakes reduces GHGs.

Response:

Please refer to the response to BCSEA IR 1.13.2.

13.5 Please provide FEU's current analysis of NGT GHG emissions relative to the alternatives.

Response:

The FEU's current analysis of NGT GHG emissions is based on the latest carbon intensity values approved by the BC Ministry of Energy and Mines, which are derived from the GHGenius model v4.03.

Diesel is the most common fuel used by the fleet operators targeted by the NGT program; therefore the carbon intensity for diesel is compared to that of CNG and LNG. The amount of

GHG emission reduction is measured as the net reduction in CO_2 emissions between diesel and CNG or diesel and LNG.

The carbon intensity values for each fuel type used in the GHG emission analysis is summarized in the table below:

Fuel	gCO2e per GJ
Compressed Natural Gas	62,140
Liquefied Natural Gas	63,260
Diesel	93,550

13.5.1 Please provide information on a per-vehicle basis and on a per-vehicle-type (or vessel-type) basis.

Response:

In the table below, FEI has provided forecast consumption for each type of transportation application and the resultant reduction in GHG emission on a CO2e basis using the approved carbon intensity values from the GHGenius v4.03 model. The figures shown in column (f) represent the quantity of CO2e GHG emissions in kilograms that are reduced for each type of transport application each year by switching from diesel to natural gas.

(a)	(b)	(c)	(d)	(e)	(f)
NGT Application	**Fuel Used**	**Natural Gas Consumption (GJ/year)**	**Diesel Fuel (kg of CO2e)**	**Natural Gas (kg of CO2e)**	**Reduction in CO2e (kg/vessel/year)**
Buses	CNG	1,000	93,550	62,140	31,410
Vocational Truck	CNG	1,000	93,550	62,140	31,410
Class 8 Tractor	LNG	4,000	374,200	253,040	121,160
Marine Vessel	LNG	100,000	9,355,000	6,326,000	3,029,000
Mine Haul Truck	LNG	18,000	1,683,900	1,138,680	545,220

Fuel	Carbon Intensity (kg CO2e/GJ)
CNG	62.14
LNG	63.26
Diesel	93.55

13.5.2 Please provide a breakdown of emissions assessments according to: (a) “upstream” emissions, i.e. from the drilling, production and upgrading of the fuel; (b) the storage, long-distance transportation and distribution of the fuel; and (c) the end use of the fuel to power transportation.

Response:

The FEU rely on GHGenius model that has been accepted both provincially and federally as the model to measure the total lifecycle amount of greenhouse gas emissions for various sources of fuel. Accordingly, the FEU use the CO2e intensity results for various fuel sources produced by GHGenius.

The FEU use these figures to calculate the reduction in CO2e emissions for natural gas vs the comparable alternative fuel that has been displaced; which is diesel in the case of NGT applications. The FEU are not involved in the back end functions of the model, and is therefore not able to provide the analysis requested.

13.5.3 If FEU relies on GHGenius or some other authority for FEU’s GHG assessment of NGV, please provide the most current assessment by that authority.

Response:

Please refer to the response to BCSEA IR 1.13.5.

13.6 What global warming potential or potentials (GWP) do FEU use for methane, and what time period or periods do FEU use for analyzing the GHG impacts of NGV?

Response:

Please refer to the response to BCSEA IR 1.13.5.2. As mandated by the provincial government, GHGenius has been approved as the model that will be used to measure GHG emission reductions. FEU does not analyze global warming potentials for methane.

The FEU reports GHG emissions on an annual basis over the time period that the NGV is in operation. In other words, if an NGV has a ten year life, then GHG emissions are measured and reported each year for ten years.

13.7 What rates of methane leakage do FEU assume for (a) “upstream emissions,” i.e. from drilling, production and upgrading of the fuel; (b) for storage, long-distance transportation and distribution of the fuel; and (c) for the end use of the fuel for transportation?

Response:

Please refer to the response to BCSEA IR 1.13.6. GHGenius is the approved model used for measuring GHG emissions, and it provides the carbon dioxide intensity for various fuels. The FEU use this tool and does not perform its own analysis on these emissions for the purpose of the GGRR activities.

13.8 What rates of carbon dioxide emissions associated with power use do FEU assume for (a) “upstream emissions,” i.e. from drilling, production and upgrading of the fuel; and (b) for storage, long-distance transportation and distribution of the fuel?

Response:

Please refer to the response to BCSEA IR 1.13.5.2.

13.9 Does FEU monitor and assess the development of scientific research on whether or not projects, programs, contracts or expenditures undertaken under the GGRR would actually reduce or increase GHG emissions in BC?

Response:

No. The FEU rely on industry-expert generated research to gauge the impact of projects and programs undertaken under the GGRR with respect to GHG emissions in BC. For instance, GHGenius is a widely accepted model that is used by both provincial and federal regulatory authorities to gauge the impact of GHG emissions of various fuels in a number of different jurisdictions. Any applicable scientific research findings which would impact the GHGenius model would be incorporated into the model by the appropriate expert.

However, it is the role of the government, as author of the GGRR, to determine if emissions are reduced via specific activities or not.

14.0 Topic: NGT upstream GHG emissions

Reference: ***A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas*, Robert W. Howarth 2014, Energy Science and Engineering (http://onlinelibrary.wiley.com/enhanced/doi/10.1002/ese3.35) (Howarth 2014)**

14.1 Please file a copy of Howarth 2014.

Response:

Please refer to Attachment 14.1 for a copy of the requested report.

14.2 Does FEU agree that the author, Robert W. Howarth is a scientific professional working out of Cornell University in the US who has published previous research on the GHG footprint of natural gas?

Response:

The FEU are not aware of Mr. Howarth's credentials.

14.3 Does FEU agree that "*A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas*" (Howarth 2014) provides an up-to-date review of scientific research on the GHG emissions of conventional natural gas and natural gas from "unconventional" sources including shale formations, compared to GHG emissions from coal and diesel oil? If not, please explain.

Response:

The document speaks for itself, the FEU has no comment.

14.4 Please provide a detailed reconciliation between the GHG emission rates given in Howarth 2014 (Table 1, page 3) and those assumed by FEU for FEU's NGV and GGRR programs and activities. In particular, please reconcile between the data expressed by Howarth as a "percentage of the lifetime production of a gas well (normalized to the methane content of the natural gas)" and whatever emission rate FEU relies on.

Response:

As indicated in the response to BCSEA IR 1.13.2, the FEU rely on GHGenius to measure GHG emissions. Comparison of the Howarth (2014) study to the GHGenius model is not considered within the scope of this LTRP.

14.5 Please detail the additional assumptions and factors the FEU uses for efficiencies and gas leakage between the point of delivery of the fuel to the end use for transportation.

Response:

Please refer to the responses to BCSEA IRs 1.13.6, 1.13.7 and 1.14.04.

14.6 Does FEU agree with Howarth's characterization of information on upstream emissions of methane (page 4, bottom of left column) as "poorly documented and highly uncertain," albeit being supplemented by "a more robust approach" in new research? Do FEU believe this characterization applies to the situation in BC? Please discuss.

Response:

The FEU take no position with regard to the opinions of Mr. Howarth. Please refer to the responses to BCSEA IRs 1.14.1 and 1.14.2.

14.7 Are the GHG emissions data that FEU relies on sensitive to assumptions about the lifetime production of gas wells, as discussed by Howarth (page 4, top of right column)?

Response:

Please refer to the responses to BCSEA IRs 1.13.6, 1.13.7 and 1.14.04.

14.8 Please comment on the use in Howarth 2014 (Table 2, page 7) of 20-year and 100-year time scales for the GWP of methane and the specific GWP values used by Howarth. Do these values and approach differ from those on which FEU rely?

Response:

Please refer to the response to BCSEA IR 1.14.04.

The scientific merits of differing global warming potentials (GWP) are considered outside the scope of the LTRP. As per the British Columbia Ministry of Energy and Mines GHG reporting requirements, FEU has adopted IPCC SAR 1995 GWP values.

14.9 What is FEU's opinion of the relative importance of a 20-year time period versus a 100-year time period for assessing the global warming significance of methane?

Response:

Please refer to the response to BCSEA IR 1.14.04.

The FEU's opinion regarding the differing time frames associated with global warming potential (GWP) calculation is not considered within the scope of this LTRP. The FEU report emissions based on the values produced by GHGenius, and have adopted IPCC SAR 1995 GWP values based upon the British Columbia Ministry of Energy and Mines GHG reporting requirements.

14.10 Citing Brandt, et al [29] and Alvarez, et al [40], Howarth says that "using natural gas to replace diesel fuel as a long-distance transportation fuel would greatly increase greenhouse emissions," based in part on expected methane leakage from fuelling operations and the lower efficiency of methane-fuelled transportation relative to diesel. Please comment.

Response:

Please refer to the response to BCSEA IR 1.14.04.

The FEU have not reviewed Howarth (2014) and cannot comment on details surrounding the estimated emissions.

14.11 Please comment on the use in Howarth 2014 (Table 2) of 20-year and 100-year time scales for the GWP of methane and the specific GWP values used by Howarth.

Response:

Please refer to the response to BCSEA IR 1.14.04.

14.12 Does FEU agree that the findings and analysis in Howarth 2014 are credible? Please discuss.

Response:

Please refer to the responses to BCSEA IRs 1.14.3 and 1.14.04.

15.0 Topic: *GHG Reduction (Renewable and Low Carbon Fuel Requirements) Act*

Reference: Exhibit B-1, Appendix A-5, page 8 (pdf p. 313)

"Since the FEU sell natural gas for use in transportation applications under various rate classes, the Companies have the opportunity to claim first sale as a Part 3 fuel supplier in the province. The RLCFRR [Renewable and Low Carbon Fuel Requirements Regulation] allows for generation of low carbon compliance credits based on a required carbon intensity baseline. Suppliers that are not in compliance with the mandated carbon reductions must purchase credits from others or pay a penalty. As the FEU add more CNG and LNG sales, the Companies' credits will increase as they are measured against the conventional fuel intensity baseline, which creates a potential revenue stream and benefit to customers through this deferral account mechanism. The FEU are awaiting further clarification from the Government regarding the definition of Part 3 Fuel Suppliers as it relates to natural gas for transportation."

15.1 On what time-line does FEU expect to receive further clarification from the government regarding the definition of Part 3 Fuel Suppliers as it relates to natural gas for transportation?

<u>Response:</u>

The clarification referred to in the paragraph relates specifically to CNG. As defined by the RLCFRR, a Part 3 fuel supplier is someone who manufactures fuel for use in transportation, and therefore owns the associated carbon credit generated from this fuel sale.

In the case of LNG, FEU liquefies the natural gas before it is sold for use in transportation. In this case FEU is the manufacturer, and therefore who owns the gas and associated carbon credit. In the case of CNG, the manufacturer is the person who owns the natural gas at the time of compression. It is the point at which natural gas is compressed that was in question.

The Ministry has re-iterated its position that once natural gas is transferred from FEU's pipeline through the meter, title has transferred to the customer. Therefore it is the customer who owns the CNG and the associated carbon credits.

Accordingly, the FEU will report on all LNG sales for use in transportation, and claim carbon credits related to this sale. The FEU will not claim carbon credits for CNG sales. However for customers who don't have the resources to undertake the reporting process, the FEU iare open to reporting on behalf of these customers and flowing any potential benefit back to the customer.

15.2 What specific clarification is FEU awaiting from the government, and how will such clarification affect FEU's actions?

Response:

Please refer to the response to BCSEA IR 1.15.1.

15.3 Please confirm that FEU has not recorded or sold any credits under the RLCFRR. Otherwise, please explain.

Response:

To clarify, the reporting of carbon credit reductions up to June 30, 2013 were for compliance purposes only, and therefore did not generate credits that were available to be sold. Carbon credits reductions that are reported after June 30, 2013 will be available for sale to interested parties.

The FEU have not recorded any carbon credits reductions since June 30, 2013 and therefore has not generated carbon credits that can be sold under the LCFRR.

15.4 Does FEU plan or wish to sell carbon compliance credits under RLCFRR?

Response:

Yes. Once the FEU have reported carbon credit reductions and these reductions have been verified by the Ministry, the FEU are willing to monetize these credits to interested parties under the RLCFRR.

The Ministry intended to have an online carbon credit exchange program called the Transportation Fuel Reporting System that would be fully operational and available to Part 3 Suppliers by July 1, 2013. However, the implementation has been delayed to March 31, 2015.

In the absence of a carbon credit exchange program, the FEU are unable to monetize carbon compliance credits at this time.

15.5 Please provide any summary estimates or calculations FEU has regarding the value of carbon compliance credits under RLCFRR, both unit value and total potential value to FEU.

Response:

The following table provides total eligible actual LNG sales for two operators under the NGT program, and associated carbon credits that may potentially be earned for the period from July 1, 2013 to December 31, 2013.

LNG Sales Volume (GJ)	CO2e Emissions (tonne)
95382	2003

As indicated in the response to BCSEA IR 1.15.4, all carbon credits generated under the RLCFRR must be verified by the Ministry before they are considered to be earned by FEU.

Carbon credits do not carry an assigned value. There is an opportunity to sell carbon credits earned after July 1, 2013 to any corporation that may be out of compliance with the Regulation. However, at the present time it is not known whether there will be demand for these carbon credits, and if there is demand, what the sale value might be.

16.0 Topic: Energy Efficiency and Conservation (EEC)

Reference: Exhibit B-1, p.32

"...In the absence of an overarching federal energy or climate change initiative, B.C. and the province's municipal governments have stepped in with aggressive energy and climate policies. These policies emphasize lowering energy consumption and improving energy efficiency and conservation while also encouraging the development of renewable energy sources and alternative technologies."

16.1 Does FEU's observation that government policies "emphasize lowering energy consumption and improving energy efficiency and conservation" mean that FEU's 2014 LTRP should contemplate FEU pursuing all cost-effective energy efficiency and conservation measures over the plan period? If not, why not?

<u>Response:</u>

The quote provided in the preamble above is simply describing the planning environment. The quote does not infer any position that the FEU takes on pursuing cost effective EEC measures for the purposes of the LTRP.

For the FEU's position on the cost-effectiveness of EEC measures in the LTRP, please refer to the response to BCUC IR 1.42.1. For an explanation on how the FEU have included all cost-effective EEC measures in the 2014 LTRP, please refer to the response to BCUC IR 1.43.2.1

17.0 Topic: Energy Efficiency and Conservation (EEC)

Reference: Exhibit B-1, section 4.2; Figure 4-1 (p. 76), Table 4-1 (pp. 79-80), Table 4-2, p. 87, Table 4-3, p. 88

17.1 Please discuss the estimated EEC savings for the Reference Case and Scenarios B & C with respect to the potential achievement of all cost-effective EEC.

Response:

The estimated EEC savings in the Reference Case, and Scenarios B and C, include consideration of all cost effective EEC. For the purposes of the 2014 LTRP, all cost effective EEC/DSM measures were identified by the Conservation Potential Review (CPR) as defined by the current *Demand Side Measures Regulation*.

As described in Section 4.2 of the 2014 LTRP, the CPR provides an understanding of the potential for energy savings from EEC activity, and previous LTRP and EEC funding requests have together examined the appropriate level of funding that the FEU should be investing in EEC activities. The analysis of long term potential natural gas savings in the 2014 LTRP therefore focuses on the potential range of savings under scenarios of different future planning environments rather than scenarios entailing different funding levels.

For the EEC analysis, the scenarios examined were limited to the Reference Case scenario and the scenarios which resulted in the lowest and highest forecast of annual demand for natural gas (Scenarios B and C respectively). In this way, the Companies present the widest range of potential demand for natural gas after energy savings from cost-effective demand-side measures. The Reference Case forecast assumes that conditions that are present in the planning environment at the time the demand forecasting exercise was undertaken prevail through the planning horizon. The descriptions of Scenarios B and C are provided in Table 4.1 quoted in the question above.

17.2 To what extent do the estimated levels of EEC savings in Scenarios B & C depend on estimates of the cost-effectiveness of EEC, and to what extend do they depend on judgments of qualitative values that FEU customers may place on acquiring EEC?

Response:

The estimated levels of EEC savings depend on which measures are expected to be cost-effective under the circumstances of each future planning scenario. The cost-effectiveness of EEC/DSM is defined by the *Demand Side Measures Regulation*.

The participation levels of FEU customers in adopting the cost-effective EEC measures were estimated based on actual and projected results of FEU programs, extrapolated into the future. The qualitative judgments of the customers are therefore taken into account in that they played a role in determining the participation of customers in past programs.

17.3 Why are the estimated EEC savings lower for both Scenario B & C relative to the reference case?

Response:

In general, estimated EEC savings are lower in Scenario B because it is assumed that there is less opportunity overall to capture energy savings as there is less natural gas use. In this scenario, it is assumed that the high gas price will drive fuel switching to decentralized renewable thermal applications, and the policy environment is also assumed to drive more conservation activity that is not driven by FEU programs. Consequently, there is a corresponding overall decrease in demand for natural gas. While there is assumed to be moderate to high participation in EEC initiatives for customers who do not switch fuels, because there is less overall natural gas demand, there are fewer opportunities for natural gas savings and in some cases less savings per installed measure. As a specific example, if government policy drives more customers to upgrade to condensing boilers when their boiler fails, subsequent utility programs to improve the windows in those same facilities would result in smaller natural gas savings.

The higher natural gas price in Scenario B would normally be expected to cause some measures that fail the TRC cost-effective test in the reference case to pass instead. The basket of measures analyzed in the CPR included relatively few measures that were on the cusp of passing under the conditions of the reference case, so this effect was smaller than the effects described above.

Estimated EEC savings are lower in Scenario C largely because the low cost of gas in this scenario means some EEC measures fail the TRC cost-effectiveness test and drop out of the EEC portfolio entirely. Since there are fewer EEC programs, there is less opportunity for energy savings from EEC. One exception is where savings increase in the industrial sector. In the industrial sector, economic growth is assumed to increase levels of production by over 5% by the end of the forecast period relative to the Reference Case. Industrial measures implemented in this scenario are assumed to have greater savings potential because of the higher production volumes and gas consumption in the plants where the production increases are applied.

18.0 Topic: FEU GHG emissions

Reference: Exhibit B-1

18.1 Please provide all of FEU's most recent reports or documentation concerning GHG emissions from FEU's own operations and infrastructure, including both CO2 emissions from gas combustion for operational purposes, and intentional or unintentional methane emissions (and any other sources).

Response:

This series of questions are not in scope for the review this LTRP proceeding, however, the FEU provide the following information in an effort to be responsive.

The following is a summary of the 2012 Greenhouse Gas emissions at FEU facilities submitted to, and approved by, the BC Ministry of Environment (BC MOE). At the time of this response, 2013 GHG reports have not been published by the BC MOE and not considered available for dissemination. When approved, this information as well as previous years GHG emission data are available at the BC MOE website:

http://www2.gov.bc.ca/gov/topic.page?id=14C1FA7186124D1C8CABA452C9DFCA56

		GHG Emission (tCO2e)
FEVI	Stationary Combustion	33,795
	Venting	4,039
	Flaring	0.0896
	Fugitive	5,628
	Third Party Line Hits [1]	2,407
FEI	Stationary Combustion	15,518
	Venting	12,592
	Flaring	1.64
	Fugitive	47,123
	Third Party Line Hits [1]	13,231

Notes:

[1] Third party line hits is considered a venting source by the BC MOE categorization, we disagree with this classification and suggest that it is a fugitive source. We have separated the values for your review.

[2] CO2e values are based upon a GWP potential for CH4 and N2O of 21 and 310, respectively.

18.2 Please describe how FEU organizes and structures its internal management of FEU's own GHG emissions, including monitoring, reporting, planning and mitigation.

Response:

GHG sources are identified and updated annually with operational department leads; external, third party verification also occurs annually, per provincial requirements. The information is adopted into a carbon data management system which monitors and calculates GHG emission for the purposes of annual regulatory reporting. GHG related events and input data (e.g., operation hours, compressor station blowdown events, etc.) are monitored and tracked through these internal FEU systems, access to which is restricted to the Environmental team within which the reporting is reviewed and filed with the Ministry of Environment, and Environment Canada, per the deadlines required (a certified CSA Greenhouse Gas – Internal Quantifier prepares the reporting for sign off by the Director, Environment, Health and Safety).

18.3 Please describe FEU's external contacts with industry and government concerning GHG emissions reductions, such as regarding the B.C. GHG emissions reductions targets and/or federal GHG reporting.

Response:

The FEU have proactively engaged with both regulatory and industry partners in support of provincial and federal GHG regulation development and reporting. As a member of the Canadian Gas Association, and of the Canadian Energy Partnership for Environmental Innovation, the FEU provide yearly GHG and CAC emissions' data for the development of an industry emission database. This data is available in aggregate on the CGA website. In addition, the FEU periodically invests in studies that examine initiatives such as technology available for Combined Heat and Power / District Energy technology, the development of organization-specific emission factors, and the development of industry metrics. Lastly, the FEU is a member of the Canadian Energy Pipeline Association Climate Change working group and has met with the BC Ministry of Environment to work through the technical challenges surrounding WCI350 reporting requirements.

18.4 Please provide, or identify in the filed material, FEU's estimate of its historical annual GHG emissions, and forecasts for the plan period.

Response:

Information regarding the FEU's historical emissions from operations is not a matter for the 2014 LTRP and is therefore not included in the Plan. Historical emissions related operational activities are provided in the following table.

	Estimated GHG Emission (tCO2e)
2009	171,312
2010	156,467
2011	137,059
2012	134,303

Note: GWP values for CH_4 and N_2O of 21 and 310, respectively.

18.5 Please describe any internal or external targets or expectations applicable to FEU's own GHG emissions during the plan period.

Response:

The FEU consider managing 'own use' operational emissions are part of the company's ongoing operations, and not a matter for the 2014 Long Term Resource Plan. Where emissions are relevant to resource planning, such as how emissions' regulation may or does impact forecasted demand, information has been provided in the 2014 LTRP.

18.6 Please identify where in the 2014 LTRP FEU addresses its own GHG emissions, for example in terms of monitoring, reporting and mitigation.

Response:

The FEU consider managing 'own use' emissions, including monitoring, reporting, and mitigation, as part of the company's ongoing operations, and not a matter for resource planning. As such, the company did not include these emissions in the 2014 LTRP; where emissions are relevant to resource planning, such as how or if emissions' regulation may impact forecasted demand, information has been provided in the 2014 LTRP.

18.7 Does FEU consider that its current approach to its own GHG emissions, in terms of monitoring, reporting and mitigation, is acceptable (a) for the present and (b) for the duration of the plan period?

Response:

Please refer to the response to BCSEA IR 1.18.6.

18.8 What steps does FEU intend to take over the plan period to strengthen and improve its monitoring, reporting and mitigation of its own GHG emissions?

Response:

As part of its provincial regulatory commitments, and in an effort to continually strengthen and improve the emissions' management program within the company, the FEU are currently developing incident specific emission rates for third party line hits, distribution pipeline blow downs, as well from as installation of sage meters to measure for the fugitive emission from compressor valve seals. Emissions from these sources are essential for the safe and proper operation of FEU assets, and are not intended to reduce emissions, but instead monitor the amount. In addition, as per provincial regulatory requirements, yearly leak detection surveys are conducted at compressor stations, to identify potential sources of fugitive equipment. These surveys are in addition to continuous gas monitors and maintenance activities conducted by FEU operation staff which serve to reduce fugitive emission from FEU facilities.

18.9 Does FEU acknowledge that there are fugitive methane emissions from the FEU infrastructure?

Response:

The FEU acknowledge that there are fugitive methane emissions within the FEU operating infrastructure.

18.10 Please provide copies of any reports concerning fugitive methane emissions from the FEU infrastructure.

Response:

The FEU consider managing 'own use' emissions are part of its ongoing operations and not a matter for resource planning. Please refer to the response to BCSEA IR 1.18.1 for a summary of the total fugitive emissions for the organization and the location where the requested information is publicly available.

18.11 Figure 2-9, Exhibit B-1, p.34, "2010 Greenhouse Gas Emissions by Sector in B.C.," shows "Fugitive Emissions" as "10%". Please provide a breakdown of this "Fugitive Emissions" figure by sector or source.

Response:

Figure 2-9, as referenced in the FEU LTRP, was taken from the BC Ministry of Environment (BC MOE) 2010 GHG Inventory Report. The intent of the figure is to demonstrate that a large proportion of the provincial GHG emission (total) is the result of emissions from the transportation sector. If the query relates to additional details associated with the pie graph, it is suggested that communication with the BC MOE be conducted. A definition of fugitive emissions is provided in the original source as "intentional or unintentional emissions from the production, processing, transmission, storage, and delivery of fossil fuels; and from the combustion of fossil fuels not used to generate useful heat or electricity". No further breakdown of this source is currently available.

18.11.1 What portion of this "Fugitive Emissions" figure is attributable to FEU's operations and infrastructure? Please specify the Global Warming Factor assumptions used.

Response:

According to the source of this figure, the total amount of BC fugitive emissions for 2010 was 6,235 x 103 tCO2. For the same time period, fugitive emissions from the FEU system were 72,858 tCO2e. Based upon these values, a percentage attributable to FEU operations was 1.2%. A GWP of 21 was used for methane.

19.0 Topic: Methane leakage from natural gas infrastructure

Reference: Howarth 2014, Table 1

Howarth 2014, Table 1, reproduced below, provides various estimates of methane emissions from natural gas systems downstream of production. For example, the Table shows an EPA estimate of 0.9%.

Table 1. Full life cycle-based methane emission estimates, expressed as a percentage of total methane produced in natural gas systems, separated by upstream emissions for conventional gas, upstream emissions for unconventional gas including shale gas, and downstream emissions for all natural gas. Studies are listed chronologically, and our April 2011 study is boldfaced.

	Upstream conventional gas	Upstream unconventional gas	Downstream
EPA 1996 [5]	0.2%	–	0.9%
Hayhoe et al. [2]	1.4	–	2.5
Jamarillo et al. [4]	0.2	–	0.9
Howarth et al. [8]	**1.4**	**3.3**	**2.5**
EPA [11]	1.6	3.0	0.9
Ventakesh et al. [12]	1.8	–	0.4
Jiang et al. [13]	–	2.0	0.4
Stephenson et al. [14]	0.4	0.6	0.07
Hultman et al. [15]	1.3	2.8	0.9
Burnham et al. [16]	2.0	1.3	0.6
Cathles et al. [17]	0.9	0.9	0.7

Total emissions are the sum of the upstream and downstream emissions. Studies are listed chronologically by time of publication. Dashes indicate no values provided. The full derivation of the estimates shown here is provided elsewhere [18, 19].

19.1 How do the "Downstream" methane emissions estimate in Howarth's Table 1 compare with FEU's information regarding comparable methane emissions estimates for B.C. or other Canadian locations?

<u>Response:</u>

An assessment of downstream methane emissions' estimates for BC or other Canadian locations for the purposes of comparison with FEU's information has not been conducted by the FEU for the 2014 LTRP. The company has not considered that this type of comparison would provide meaningful information as related to the resource planning process.

19.2 What is FEU's estimate of the proportion of methane emissions from its own system as compared to the gas transmission system between production and the FEU system?

Response:

The comparison indicated in this question has not been completed by the FEU as part of the 2014 LTRP, as this type of comparison would not provide meaningful information as related to the resource planning process.

20.0 Topic: Regulation of leakage and venting

Reference: Exhibit B-1

20.1 Please describe how natural gas leakage and venting associated with FEU's system is regulated.

Response:

The FEU's venting and fugitive emissions are regulated through the BC *Greenhouse Gas Reduction Act* which stipulates the monitoring and measurement of fugitive and venting emissions via the methodology set forward through Western Climate Initiative (WCI) 350 document; furthermore, third party, external verification of this reporting is also required of the FEU annually. The FEU's emissions are also federally regulated through Environment Canada's Greenhouse Gas Emission Reporting Program. This program requires mandatory reporting of combustion, fugitive, venting, and flaring emissions for organizations that emit in excess of 50,000 tCO2e per year.

20.2 Does FEU expect the regulation of natural gas leakage and venting applicable to its system to be tightened over the plan period? Please discuss.

Response:

The management of fugitive emissions and venting is a matter of day to day business operations and outside the scope of long term resource planning. The FEU do not know if regulation of gas leakage or venting will become more stringent over the study period, but as a result of good asset management and operational practices believe they are well positioned to address any such changes.

20.3 What types of financial implications for FEU are associated with more-stringent efforts to reduce FEU's own GHG emissions, intentional or unintentional, over the plan period? For example, would such efforts affect spending for system maintenance, sustainment capital, and replacement capital?

Response:

The management of fugitive emissions and venting is a matter of day to day business operations and outside the scope of long term resource planning. However, in general terms, more stringent environmental regulations can increase capital and/or operating costs for any business. The FEU believe that the good asset management and operational practices they have in place will minimize the impact of any such cost increases that might occur.

21.0 Topic: FEU customer's fugitive GHG emissions

Reference: Exhibit B-1

21.1 What information can FEU provide regarding fugitive natural gas emissions occurring downstream of the FEU system, i.e., at the customers' facilities?

Response:

The FEU understand "fugitive natural gas emissions" or "fugitive methane emissions" at customers' facilities to be the unplanned release of natural gas or release of natural gas that is not combusted. The FEU cannot provide the requested information since the customer's meter is the boundary between the FEU's system and the customer's facility, with the exception of NGV facilities where the FEU may own assets beyond the customer meter. The FEU do not have additional information regarding fugitive GHG emissions at customers' facilities.

The FEU are not aware of any data that currently exists to quantify the extent of unplanned natural gas releases at FEU's customers' facilities. However, given the safety risk associated with unplanned releases of natural gas, the FEU advise and assist customers to reduce and eliminate the unplanned release of natural gas for safety reasons. The FEU do not expect that reducing unplanned releases of natural gas offers a significant opportunity for reducing GHG emissions in B.C.

21.1.1 How does FEU define the boundary between its system and customers' facilities for the purpose of responsibility for fugitive natural gas emissions? Is the customer revenue meter the dividing point?

Response:

Please refer to the response to BCSEA IR No. 1.21.1.

21.2 Does FEU consider that reduction of fugitive emissions, at customers' facilities, of natural gas from FEU's system presents an opportunity for reducing GHG emissions in B.C.?

Response:

Please refer to the response to BCSEA IR 1.21.1.

21.3 Does FEU currently have a role in advising or assisting customers to reduce fugitive methane emissions from customers' facilities? If so, please describe the role.

Response:

The FEU's efforts to educate their customers on natural gas safety include advising and assisting customers to inspect, clean and maintain natural gas piping, appliances, venting, combustion air supply and above-ground or buried piping past the natural gas meter. In this way, the FEU promote natural gas safety which includes taking measures to ensure that customers' natural gas piping and appliances do not leak "fugitive natural gas emissions" or unintentionally release natural gas into the atmosphere.

21.4 In FEU's view would it be (a) appropriate and (b) helpful for FEU to expand its role in advising or assisting customers to reduce fugitive methane emissions from customers' facilities over the planning period?

Response:

The FEU believe that the current level of natural gas safety education efforts (identified in the response to BCSEA IR 1.21.3) is appropriate and do not find that it would be helpful to expand this role in advising and assisting customers to reduce "fugitive methane emissions" (as defined in the response to BCSEA IR 1.21.1) from customers' facilities over the planning period.

Attachment 11.12

TECHNOLOGY

LEVERAGING NATURAL GAS TO REDUCE GREENHOUSE GAS EMISSIONS

CENTER FOR CLIMATE
AND ENERGY SOLUTIONS

June 2013

LEVERAGING NATURAL GAS TO REDUCE GREENHOUSE GAS EMISSIONS

June 2013

CONTENTS

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EXECUTIVE SUMMARY

Recent technological advances have unleashed a boom in U.S. natural gas production, with expanded supplies and substantially lower prices projected well into the future. Because combusting natural gas yields fewer greenhouse gas emissions than coal or petroleum, the expanded use of natural gas offers significant opportunities to help address global climate change. The substitution of gas for coal in the power sector, for example, has contributed to a recent decline in U.S. greenhouse gas emissions. Natural gas, however, is not carbon-free. Apart from the emissions released by its combustion, natural gas is composed primarily of methane (CH_4), a potent greenhouse gas, and the direct release of methane during production, transmission, and distribution may offset some of the potential climate benefits of its expanded use across the economy.

This report explores the opportunities and challenges in leveraging the natural gas boom to achieve further reductions in U.S. greenhouse gas emissions. Examining the implications of expanded use in key sectors of the economy, it recommends policies and actions needed to maximize climate benefits of natural gas use in power generation, buildings, manufacturing, and transportation (Table ES-1). More broadly, the report draws the following conclusions:

- The expanded use of natural gas—as a replacement for coal and petroleum—can help our efforts to reduce greenhouse gas emissions in the near- to mid-term, even as the economy grows. In 2013, energy sector emissions are at the lowest levels since 1994, in part because of the substitution of natural gas for other fossil fuels, particularly coal. Total U.S. emissions are not expected to reach 2005 levels again until sometime after 2040.
- Substitution of natural gas for other fossil fuels cannot be the sole basis for long-term U.S. efforts to address climate change because natural gas is a fossil fuel and its combustion emits greenhouse gases. To avoid dangerous climate change, greater reductions will be necessary than natural gas alone can provide. Ensuring that low-carbon investment dramatically expands must be a priority. Zero-emission sources of energy, such as wind, nuclear and solar, are critical, as are the use of carbon capture-and-storage technologies at fossil fuel plants and continued improvements in energy efficiency.
- Along with substituting natural gas for other fossil fuels, direct releases of methane into the atmosphere must be minimized. It is important to better understand and more accurately measure the greenhouse gas emissions from natural gas production and use in order to achieve emissions reductions along the entire natural gas value chain.

TABLE ES-1: Sector-Specific Conclusions and Recommendations

POWER SECTOR
It is essential to maintain fuel mix diversity in the power sector. Too much reliance on any one fuel can expose a utility, ratepayers, and the economy to the risks associated with commodity price volatility. The increased natural gas and renewable generation of recent years has increased the fuel diversity of the power sector (by reducing the dominance of coal). In the long term, however, concern exists that market pressures could result in the retirement of a significant portion of the existing nuclear fleet, all of which could be replace by natural gas generation. Market pressures also could deter renewable energy deployment, carbon capture and storage, and efficiency measures. Without a carbon price, the negative externalities associated with fossil fuels are not priced by society, and therefore there will be less than optimal investment and expansion of zero-carbon energy sources.
Instead of being thought of as competitors, however, natural gas and renewable energy sources such as wind and solar can be complementary components of the power sector. Natural gas plants can quickly scale up or down their electricity production and so can act as an effective hedge against the intermittency of renewables. The fixed fuel price (at zero) of renewables can likewise act a hedge against potential natural gas price volatility.

TABLE ES-1: Sector-Specific Conclusions and Recommendations—continued

BUILDINGS SECTOR
It is important to encourage the efficient direct use of natural gas in buildings, where natural gas applications have a lower greenhouse gas emission footprint compared with other energy sources. For thermal applications, such as space and water heating, onsite natural gas use has the potential to provide lower-emission energy compared with oil or propane and electricity in most parts of the country. Natural gas for thermal applications is more efficient than grid-delivered electricity, yielding less energy losses along the supply chain and therefore less greenhouse gas emissions. Consumers need to be made aware of the environmental and efficiency benefits of natural gas use through labeling and standards programs and be incentivized to use it when emissions reductions are possible.
MANUFACTURING SECTOR
The efficient use of natural gas in the manufacturing sector needs to be continually encouraged. Combined heat and power systems, in particular, are highly efficient, as they use heat energy otherwise wasted. Policy is needed to overcome existing barriers to their deployment, and states are in an excellent position to take an active role in promoting combined heat and power during required industrial boiler upgrades and new standards for cleaner electricity generation in coming years. For efficiency overall, standards, incentives, and education efforts are needed, especially as economic incentives are weak in light of low natural gas prices.
DISTRIBUTED GENERATION
Natural gas-related technologies, such as microgrids, microturbines, and fuel cells, have the potential to increase the amount of distributed generation used in buildings and manufacturing. These technologies can be used in configurations that reduce greenhouse gas emissions when compared with the centralized power system as they can reduce transmission losses and use waste heat onsite. To realize the potential of these technologies and overcome high upfront equipment and installation costs, policies like financial incentives and tax credits will need to be more widespread, along with consumer education about their availability.
TRANSPORTATION SECTOR
The greatest opportunity to reduce greenhouse gas emissions using natural gas in the transportation sector is through fuel substitution in fleets and heavy-duty vehicles. Passenger vehicles, in contrast, likely represent a much smaller emission reduction opportunity even though natural gas when combusted emits fewer greenhouse gases than gasoline or diesel. The reasons for this include the smaller emission reduction benefit (compared to coal conversions), and the time it will take for a public infrastructure transition. By the time a passenger fleet conversion to natural gas would be completed, a new conversion to an even lower-carbon system, like fuel cells or electric vehicles, will be required to ensure significant emissions reductions throughout the economy.
INFRASTRUCTURE
Transmission and distribution pipelines must be expanded to ensure adequate supply for new regions and to serve more thermal loads in manufacturing, homes, and businesses. Increased policy support and innovative funding models, particularly for distribution pipelines, are needed to support the rapid deployment of this infrastructure.

I. OVERVIEW OF MARKETS AND USES

By Meg Crawford and Janet Peace, C2ES

INTRODUCTION

Recent technological advances have unleashed a boom in natural gas production, a supply surplus, and a dramatically lower price. The ample supply and lower price are expected to continue for quite some time, resulting in a relatively stable natural gas market. As a consequence, interest in expanding the use of natural gas has increased in a variety of sectors throughout the economy, including power, buildings, manufacturing, and transportation. Given that combusting natural gas yields lower greenhouse gas emissions than that of burning coal or petroleum, this expanded use offers significant potential to help the United States meet its climate change objectives. Expanded use of gas in the power sector, for example, has already led to a decrease in U.S. greenhouse gas emissions because of the substitution of gas for coal. It is important to recognize, however, that natural gas, like other fossil fuel production and combustion, does release greenhouse gases. These include carbon dioxide and methane; the latter is a higher global warming greenhouse gas. Accordingly, a future with expanded natural gas use will require diligence to ensure that potential benefits to the climate are achieved. This report explores the opportunities and challenges, sector by sector throughout the U.S. economy, and delves into the assortment of market, policy, and social responses that can either motivate or discourage the transition toward lower-carbon and zero-carbon energy sources essential for addressing climate change.

CONTEXT: A NEW DOMINANT PLAYER

Throughout its history, the United States has undergone several energy transitions in which one dominant energy source has been supplanted by another. Today, as the country seeks lower-carbon, more affordable, domestically sourced fuel options to meet a variety of market, policy, and environmental objectives, the United States appears poised for another energy transition. Past energy transitions, for example, from wood to coal, took place largely without well-defined policies and were not informed by other big-picture considerations. Transitions of the past were largely shaped by regional and local economic realities and only immediate, local environmental considerations. The potential next energy transition can be more deliberately managed to achieve economic and environmental goals. The United States possesses the technological capacity and policy structures to do this. This report outlines, sector by sector, those technological options and policy needs.

The history of energy consumption in the United States from 1800 to 2010 moved steadily from wood to coal to petroleum (Figure 1). In the latter half of the 19th century, coal surpassed wood as the dominant fuel. Around 1950, petroleum consumption exceeded that of coal.

Petroleum still reigns supreme in the United States; however, due to a number of factors including improving fuel economy standards for vehicles, its use since 2006 is in decline. At the same time, for reasons that this report explores in depth, natural gas use is on the rise. As these trends continue, it is entirely possible in the coming decades that natural gas will overtake petroleum as the most popular primary energy source in the United States.[1]

Natural gas already plays a large role in the U.S. economy, constituting 27 percent of total U.S. energy consumption in 2012. Unlike other fossil fuels, natural gas has applications in almost every sector, including generating electricity; providing heat and power to industry, commercial buildings, and homes; powering vehicles; and as a feedstock in the manufacture of industrial products.

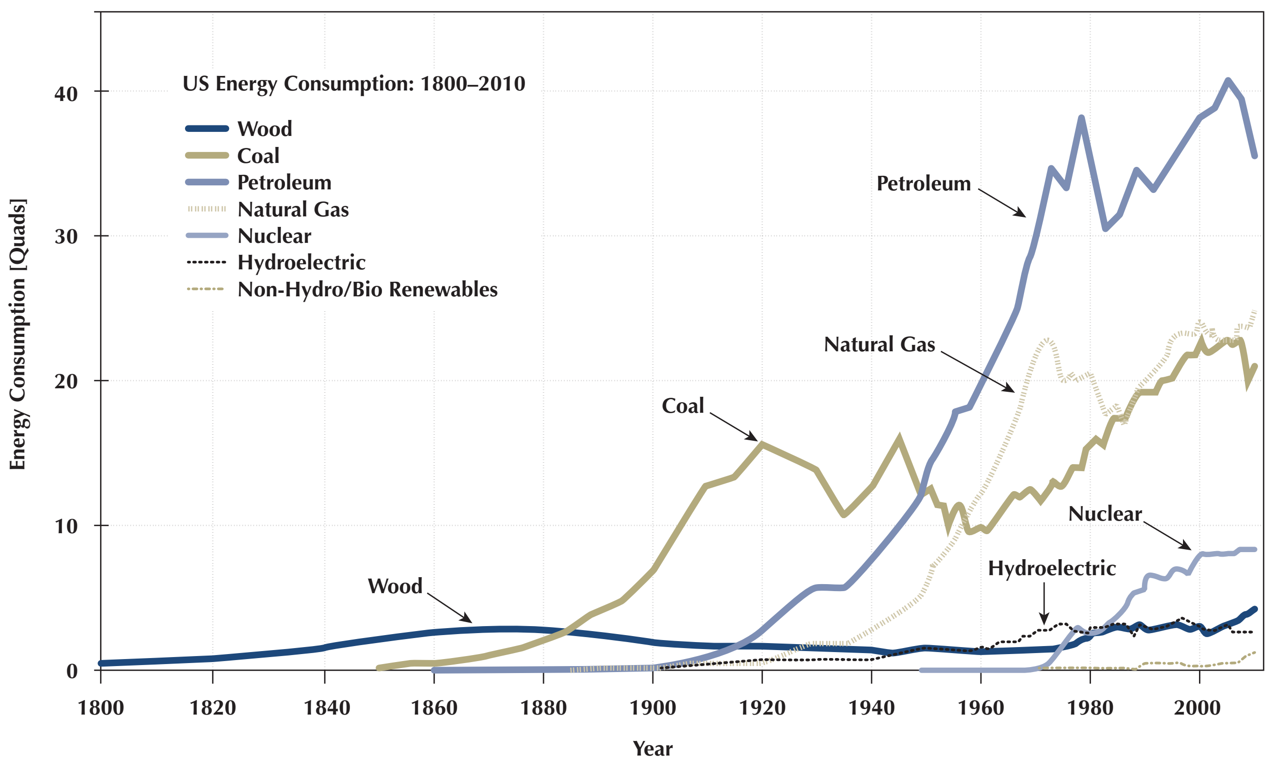
By all accounts, the existing increase in natural gas supply appears very certain, and the large domestic supply is expected to keep natural gas prices relatively low in the near to medium term. Furthermore, the domestic supply already has and is forecasted to deliver substantial benefits to the U.S. economy, providing jobs and increasing the gross domestic product. The primary uncertainties for the natural gas market are how quickly the expanded use will occur and the specific ways in which specific sectors of the economy will be affected. This report delves into the assortment of market, policy, and social responses that can motivate or discourage this transition. It places this energy transition firmly in the context of the closely related climate impacts of different types of energy use, and explores the interplay between economic opportunities and the pressing need to dramatically reduce the economy's emissions of greenhouse gases.

CLIMATE IMPLICATIONS

The expanding use of natural gas is already reducing emissions of carbon dioxide (CO_2), the primary greenhouse gas, at a time in which the U.S. economy is growing. In 2011, total U.S. CO_2 emissions were down by nearly 9 percent from peak levels of 6,020 million metric tons in 2007. This decrease is due to a number of factors, of which the increased use of natural gas in the power sector is prominent. Demand is increasing as new and significantly more efficient natural gas power plants have been recently constructed, existing natural gas power plants are being used more extensively, and fuel-substitution from coal to natural gas is taking place. Compared to coal, natural gas is considered relatively clean because when it is burned in power plants, it releases about half as much CO_2 (and far fewer pollutants) per unit of energy delivered than coal. As the fraction of electric power generated by coal has fallen over the last six years and been replaced mostly by natural gas-fueled generation and renewables, total U.S. CO_2 emissions have decreased.

According to several sources, including the U.S. Energy Information Administration (EIA), additions in electric power capacity over the next 20 years are expected to be predominantly either natural gas-fueled or renewable (discussed further in chapter 4 of

FIGURE 1: Total U.S. Energy Consumption, 1800 to 2010



Source: Energy Information Administration, "Annual Energy Review," Table 1.3. September 2012. Available at: http://www.eia.gov/totalenergy/data/annual/index.cfm#summary

Note: Wood, which was the dominant fuel in the United States for the first half of the 19th century, was surpassed by coal starting in 1885. Coal as the dominant fuel was surpassed by petroleum in 1950. Within one to two decades, natural gas might surpass petroleum as the dominant energy provider.

this report). Therefore, as coal's share of generation continues to diminish, the implications for climate in the near and medium term are reduced CO_2 emissions from the power sector. Further reductions in CO_2 emissions are possible if natural gas replaces coal or petroleum in other economic sectors. In addition, wider use of distributed generation technologies in the manufacturing, commercial, and residential sectors, namely natural gas-fueled combined heat and power (CHP) systems, has great potential to significantly reduce U.S. CO_2 emissions.

In the long term, however, the United States cannot achieve the level of greenhouse gas emissions necessary to avoid the serious impacts of climate change by relying on natural gas alone. Also required is the development of significant quantities of zero-emission sources of energy, which economic modeling shows will require policy intervention. Since many of these energy sources, such as wind and solar, are intermittent and current energy storage technology is in its infancy, natural gas will likely also be needed in the long term as a reliable, dispatchable backup for these renewable sources.

Crucially, natural gas is primarily methane, which is itself a very potent greenhouse gas. Methane is about 21 times more powerful in its heat-trapping ability than CO_2 over a 100-year time scale. With increased use of natural gas, the direct releases of methane into the atmosphere throughout production and distribution have the potential to be a significant climate issue. Regulations have already been promulgated by the Environmental Protection Agency (EPA) that address this key issue. For example, "green completion" rules for production will require all unconventional wells to virtually eliminate venting during the flow-back stage of well completion through flaring or capturing natural gas. Releases need to be carefully managed, and EPA regulation of the natural gas sector will ensure that the climate benefits from transitioning to natural gas are truly maximized.

ABOUT THIS REPORT

To examine the possible ways in which this energy transition might unfold and the potential implications for the climate, the Center for Climate and Energy Solutions and researchers at The University of Texas prepared 9 discussion papers looking at individual economic sectors, natural gas technologies, markets, infrastructure, and environmental considerations. Then, two workshops brought together dozens of respected thought leaders and stakeholders to analyze the potential to leverage natural gas use to reduce greenhouse gas emissions. Stakeholders included representatives of electric and natural gas utilities, vehicle manufacturers, fleet operators, industrial consumers, homebuilders, commercial real estate operators, pipeline companies, independent and integrated natural gas producers, technology providers, financial analysts, public utility and other state regulators, environmental nonprofits, and academic researchers and institutions.

This report is the culmination of these efforts. First, it provides background on natural gas and the events leading to the present supply boom. Next, it lays out the current and projected U.S. natural gas market, including the forecast price effects during the transition. It details the relationship between natural gas and climate change and then explores the opportunities and challenges in the power, buildings, and manufacturing sectors. It looks at technologies for on-site (distributed) electricity generation using natural gas, followed by prospects for increasing natural gas consumption in the transportation sector. Finally, the report examines the state of natural gas infrastructure and the barriers to its needed expansion.

This report offers insight into ways to lower the climate impact of natural gas while increasing its use in the electric power, buildings, manufacturing, and transportation sectors, and looks at infrastructure expansion needs and what future technologies may portend for low-emission natural gas use. This report is the product solely of the Center for Climate and Energy Solutions (C2ES) and may not necessarily represent the views of workshop participants, the C2ES Business Environmental Leadership Council or Strategic Partners, or project sponsors.

BACKGROUND

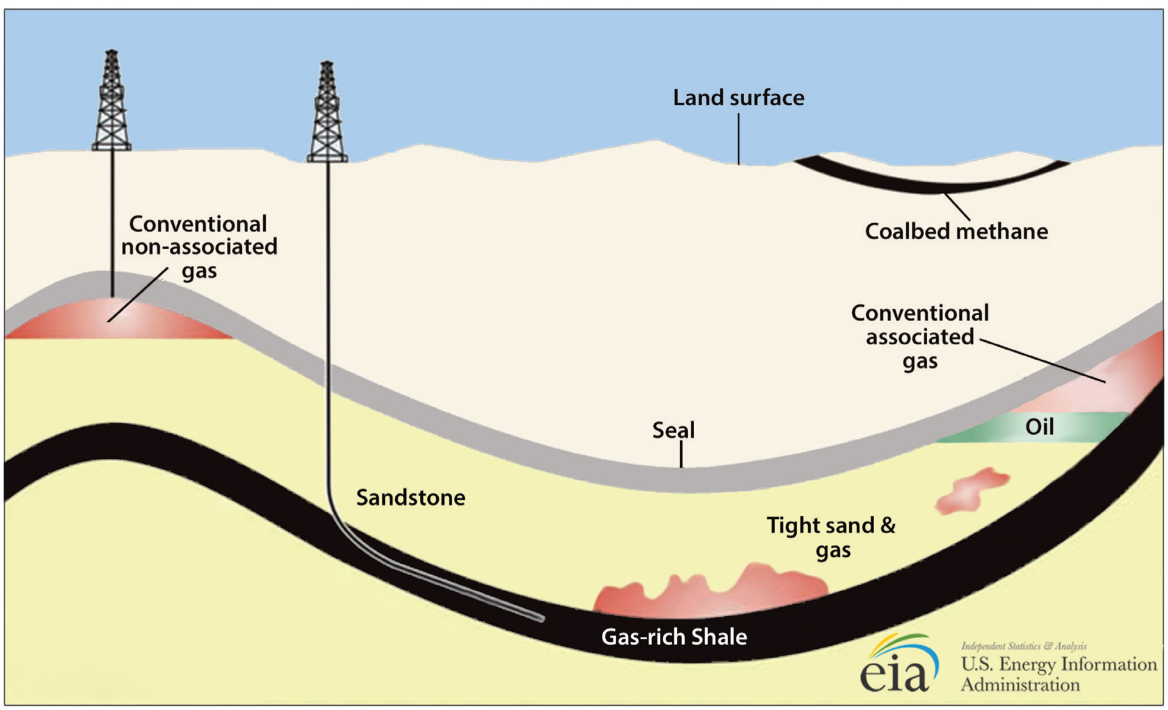
Natural gas is a naturally occurring fossil fuel consisting primarily of methane that is extracted with small amounts of impurities, including CO_2, hazardous air pollutants, and volatile organic compounds. Most natural gas production also contains, to some degree, heavier liquids that can be processed into valuable byproducts, including propane, butane, and pentane.

Natural gas is found in several different types of geologic formations (Figure 2). It can be produced alone from reservoirs in natural rock formations or be associated with the production of other hydrocarbons such as oil. While this "associated" gas is an important source of domestic supply, the majority (89 percent) of U.S. gas is extracted as the primary product, i.e., non-associated.[2]

With relatively recent advances in seismic imaging, horizontal drilling, and hydraulic fracturing, U.S. natural gas is increasingly produced from unconventional sources such as coal beds, tight sandstone, and shale formations, where natural gas resources are not concentrated or are in impermeable rock and require advanced technologies for development and production and typically yield much lower recovery rates than conventional reservoirs.[3] Shale gas extraction, for example, differs significantly from the conventional extraction methods. Wells are drilled vertically and then turned horizontally to run within shale formations. A slurry of sand, water, and chemicals is then injected into the well to increase pressure, break apart the shale to increase permeability, and release the natural gas. This technique is known as hydraulic fracturing or "fracking."

The remarkable speed and scale of shale gas development has led to substantial new supplies of natural gas making their way to market in the United States. The U.S. EIA projects that by 2040 more than half of domestic natural gas production will come from shale gas extraction and that production will increase by 10 trillion cubic feet (Tcf) above 2011 levels (Figure 3). The current increase was largely unforeseen a decade ago. This increase has raised awareness of natural gas as a key component of the domestic energy supply and has dramatically lowered current prices as well as price expectations for the future. In recent years, the abundance of natural gas in the United States has strengthened its competitiveness relative to coal and oil,

FIGURE 2: Geological Formations Bearing Natural Gas



Source: Energy Information Agency, "Schematic Geology of Natural Gas Resources," January 2010. Available at: http://www.eia.gov/oil_gas/natural_gas/special/ngresources/ngresources.html

Notes: Gas-rich shale is the source rock for many natural gas resources, but, until now, has not been a focus for production. Horizontal drilling and hydraulic fracturing have made shale gas an economically viable alternative to conventional gas resources.

Conventional gas accumulations occur when gas migrates from gas rich shale into an overlying sandstone formation, and then becomes trapped by an overlying impermeable formation, called the seal. Associated gas accumulates in conjunction with oil, while non-associated gas does not accumulate with oil.

Tight sand gas accumulations occur in a variety of geologic settings where gas migrates from a source rock into a sandstone formation, but is limited in its ability to migrate upward due to reduced permeability in the sandstone.

Coalbed methane does not migrate from shale, but is generated during the transformation of organic material to coal.

has expanded its use in a variety of contexts, and has raised its potential for reducing greenhouse gas emissions and strengthening U.S. energy security by reducing U.S. reliance on foreign energy supplies.

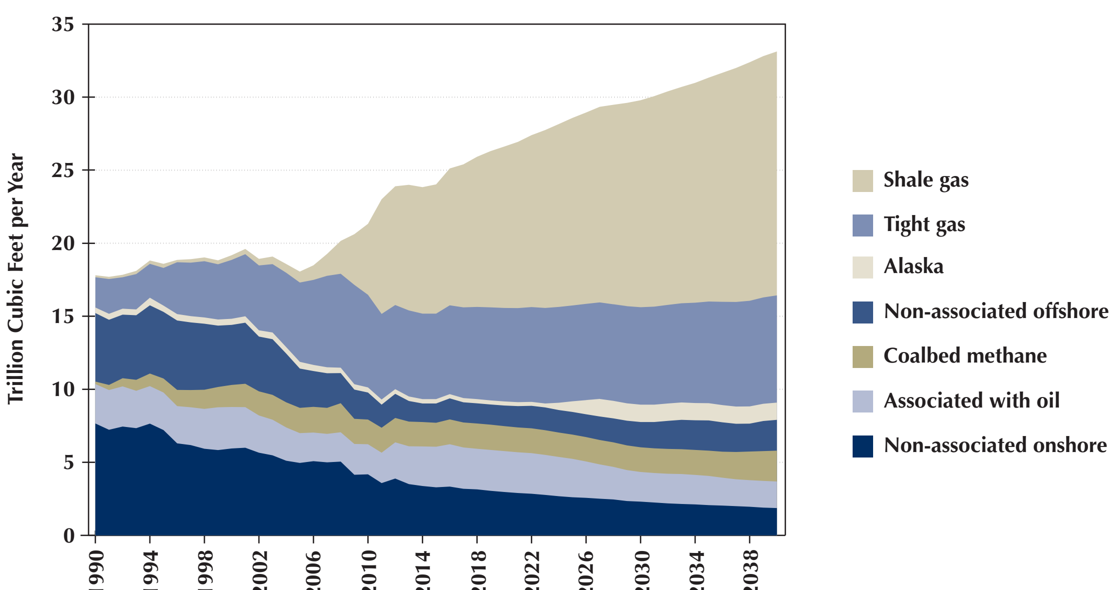
A HISTORY OF VOLATILITY: 1990 TO 2010

U.S. natural gas markets have only been truly open and competitive for about 20 years, when U.S. gas markets were deregulated and price controls were removed in the early 1990s. Before that time, government regulation controlled the price that producers could charge for certain categories of gas placed into the interstate market (the wellhead price) as well as pipeline access to market and in some cases specific uses of natural gas. The results were price signals that periodically resulted in supply shortages and little incentive for increased production. Since deregulation, price fluctuations have been pronounced, ranging from less than $2 to more than $10 per thousand cubic feet (Mcf) (Figure 4). Periods of high market prices have resulted from changes in regulation, weather disruptions, and broader trends in the economy and energy markets—but also from perceptions of abundance or scarcity in the market. A number of supply-side factors also affect prices, including the volume of production added to the market and storage availability to hedge against production disruptions or demand spikes. Looking forward, the average wellhead price is expected to be much less volatile and remain below $5 per Mcf through 2026 and rise to $6.32 per Mcf in 2035, as production gradually shifts to resources that are less productive and more expensive to extract.[4]

SUPPLIES

Since 1999, U.S. proven reserves of natural gas have increased every year, driven mostly by shale gas advancements.[5] In 2003, the National Petroleum Council estimated U.S. recoverable shale gas resources at 35 Tcf.[6] In 2012, the EIA put that estimate closer to 482 Tcf out of an average remaining U.S. resource base of 2,543 Tcf,[7] and in 2011, the Massachusetts Institute of Technology's mean projection estimate of recoverable shale gas resources was 650 Tcf out of a resource base of 2,100 Tcf.[8] By comparison, annual U.S. consumption of natural gas was 24.4 Tcf in 2011.[9] So, these estimates represent nearly 100 years of domestic supply at current levels of consumption.[10]

FIGURE 3: U.S. Dry Natural Gas Production, 1990 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release" December 2012. Available at http://www.eia.gov/forecasts/aeo/er/executive_summary.cfm

Game-Changing Technologies

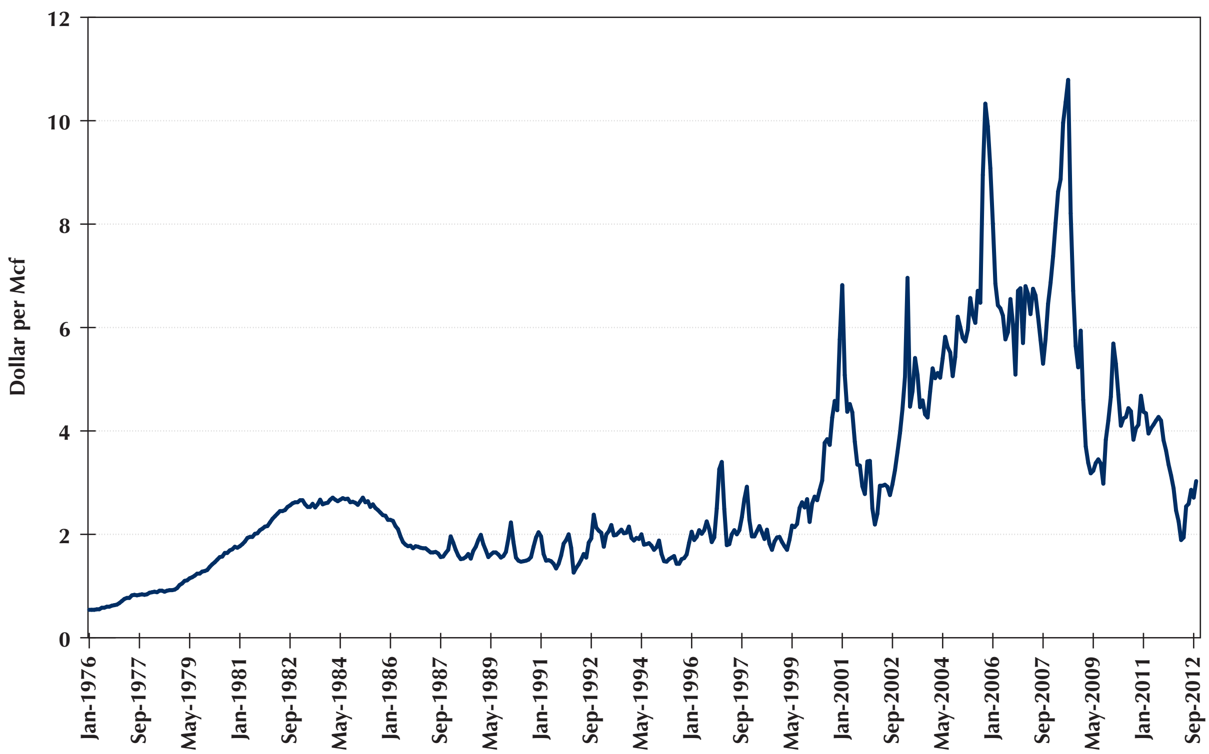
Rising natural gas prices after deregulation offered new economic incentives to develop unconventional gas resources. Advances in the efficiency and cost-effectiveness of horizontal drilling, new mapping tools, and hydraulic fracturing technologies—enabled by investments in research and development from the Department of Energy and its national labs along with private sector innovations—have led to the dramatic increase in U.S. shale gas resources that can be economically recovered.

Even as supply estimates have increased, the cost of producing shale gas has declined as more wells are drilled and new techniques are tried. In one estimate, approximately 400 Tcf of U.S. shale gas can be economically produced at or below $6 per Mcf (in 2007 dollars).[11] Another estimate suggests that nearly 1,500 Tcf can be produced at less than $8 per Mcf, 500 Tcf at less than $8 per Mcf, and 500 Tcf at $4 per Mcf.[12]

The Geography of Shale Gas Production

Shale gas developments are fundamentally altering the profile of U.S. natural gas production (Figure 3). Since 2009, the United States has been the world's leading producer of natural gas, with production growing by more than 7 percent in 2011—the largest year-over-year volumetric increase in the history of U.S. production.[13] The proportion of U.S. production that is shale gas has steadily increased as well. In the decade of 2000 to 2010, U.S. shale gas production increased 14-fold and comprised approximately 34 percent of total U.S. production in 2011.[14] From 2007 to 2008 alone, U.S. shale gas production increased by 71 percent.[15] Shale gas production is expected to continue to grow, estimated to increase almost fourfold between 2009 and 2035, when it is forecast to make up 47 percent of total U.S. production.[16] The geographic distribution of shale gas production is also shifting to new geologic formations with natural gas potential, called "plays," such as the Barnett shale play in Texas and the Marcellus shale play

FIGURE 4: U.S. Natural Gas Monthly Average Wellhead Price History, 1976 to 2012



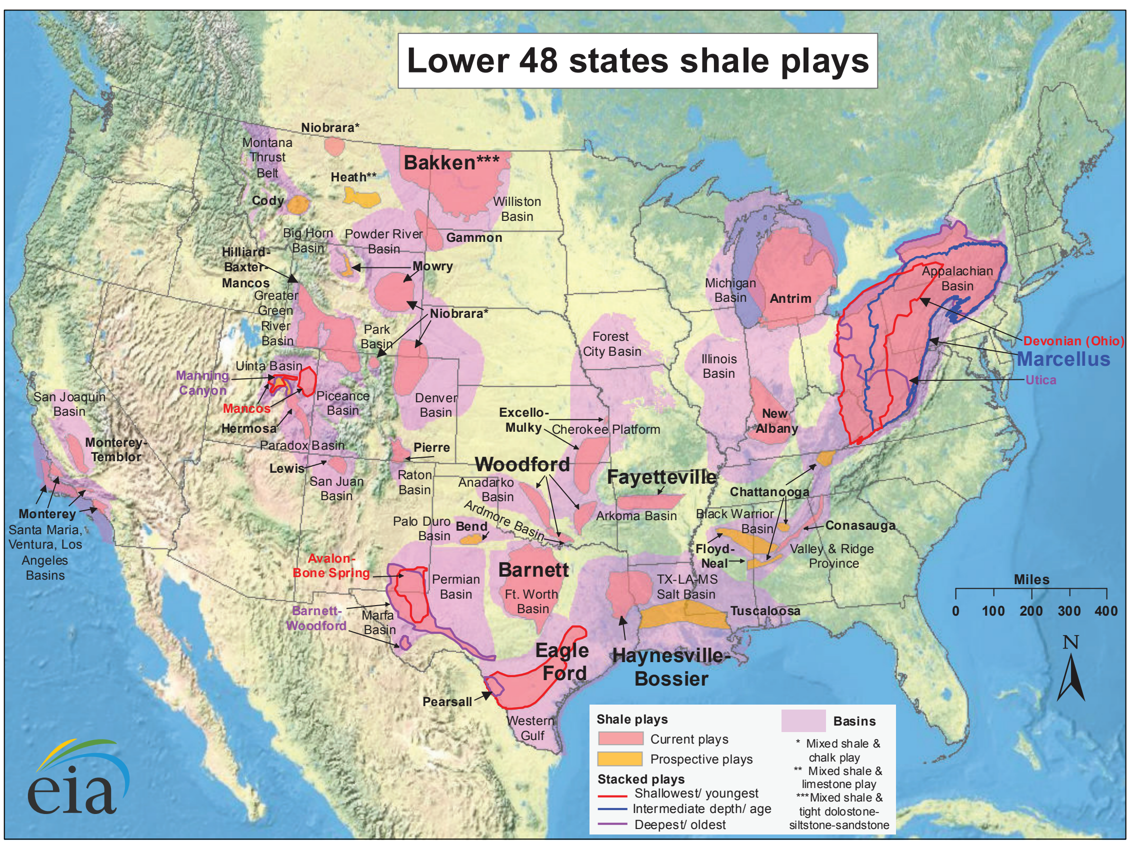
Source: Energy Information Administration, "Natural Gas Prices," 2013. Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm in the Midwest (Figure 5).[17] Natural gas is currently produced in 32 states and in the Gulf of Mexico, with 80.8 percent of U.S. production occurring in Texas, the Gulf of Mexico, Wyoming, Louisiana, Oklahoma, Colorado, and New Mexico in 2010. An increasing percentage of production is coming from states new on the scene, including Pennsylvania and Arkansas. This new geography of production has particularly large impacts for the development of natural gas infrastructure, as examined in chapter 9.

These dramatic increases in production, in combination with a weak economy and the accompanying decrease in demand for energy, are reflected in unexpectedly low and less volatile market prices, prices that encourage energy consumers to look at new uses for the fuel. Yet uncertainties remain that could hinder future development and production. For one thing, very low prices may result in producers temporarily closing down wells, particularly if the associated liquids produced along with the gas are not sufficient to make up for low natural gas prices and make well production economically viable.[18] In the long term, the dynamic nature of natural gas supply and demand will determine the price levels and volatility. Of particular importance is the extent and speed of demand expansion, a topic explored in the following section.

DEMAND

Just as supply has implications for the price path of natural gas, so does the demand. Natural gas is consumed extensively in the United States for a multitude of uses: for space and water heating in residential and commercial buildings, for electricity generation and process heat in the industrial sector, and as industrial feedstock, where natural gas constitutes the base ingredient for such varied products as plastic, fertilizer, antifreeze, and fabrics.[19] In 2012, natural gas use constituted roughly one-quarter of total U.S. primary energy consumption and was consumed in every sector of the

FIGURE 5: Lower 48 Shale Plays

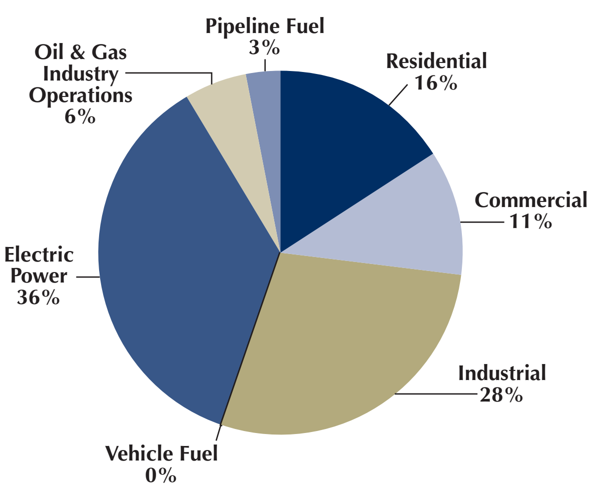


Source: Energy Information Administration, "Lower 48 States Shale Plays," May 2011. Available at: http://www.eia.gov/oil_gas/rpd/shale_gas.pdf

U.S. economy (Figure 6). Total U.S. consumption of natural gas grew from 23.3 Tcf in 2000 to 25.4 in 2012.[20] Within the overall growth, consumption in several sectors held steady, while consumption in the industrial sector declined (due to increased efficiency and the economic slowdown) and consumption in the power sector grew at an annual average rate of 3.5 percent.

In the U.S. power sector in 2010, natural gas fueled 23.9 percent of the total generation. From 2000 to 2010, electricity generation fueled by natural gas grew at a faster rate than total generation (5.1 percent versus 0.8 percent per year) (Figure 7). This growth can be attributed to a number of factors, including low natural gas prices in the early part of the decade that made natural gas much more attractive for power generation. In addition, gas-fired plants are relatively easy to construct, have lower emissions of a variety of regulated pollutants than coal-fired plants, and have lower capital costs and shorter construction times than coal-fired plants. Transportation has remained the smallest sectoral user of natural gas, with natural gas vehicles contributing to a significant percentage of the total fleet only among municipal buses and some other heavy-duty vehicles.

FIGURE 6: U.S. Natural Gas Consumption by Sector, 2012



Source: Energy Information Administration, "Natural Gas Consumption by End Use," 2013. Available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

LARGELY REGIONAL NATURAL GAS MARKETS

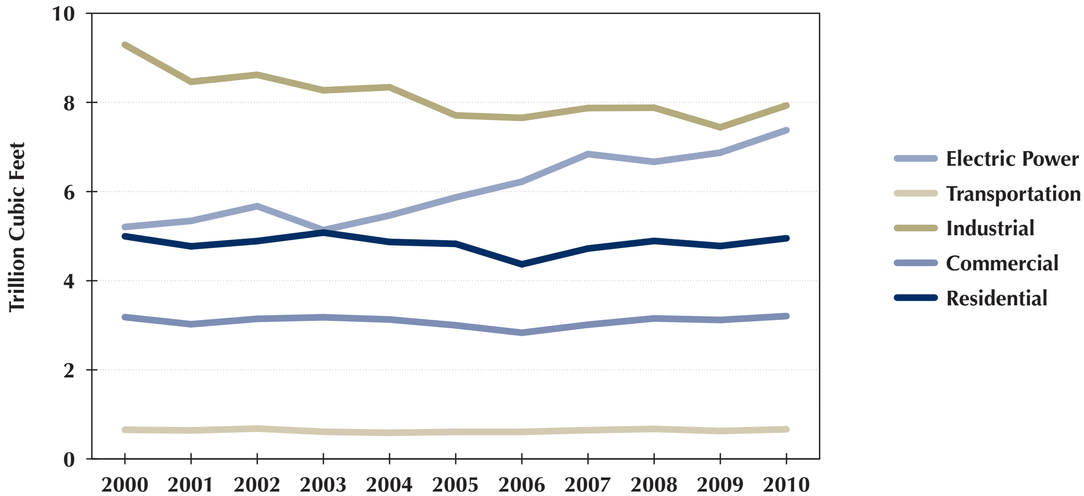
In contrast to oil, which is widely traded across national boundaries and over long distances, natural gas has been primarily a domestic resource. The low density of natural gas makes it difficult to store and to transport by vehicle (unless the gas is compressed or liquefied). (See chapter 8 for an extended discussion of liquefied and compressed natural gas.) Natural gas is therefore transported via pipelines that connect the natural gas wells to end consumers. Trade patterns tend to be more regional (particularly in the United States), and prices tend to be determined within regional markets. On the world stage, resources are concentrated geographically. Seventy percent of the world's gas supply (including unconventional resources) is located in only three regions—Russia, the Middle East (primarily Qatar and Iran), and North America. Within the United States, 10 states or regions account for nearly 90 percent of production: Arkansas, Colorado, Gulf of Mexico, Louisiana, New Mexico, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming. Significant barriers exist to establishing a natural gas market that is truly global. While most natural gas supplies can be developed economically with relatively low prices at the wellhead or the point of export,[21] high transportation costs—either via long-distance pipeline or via tankers for liquefied natural gas (LNG)—have, until recently, constituted solid barriers to establishing a global gas market.

In 2011, net imports of natural gas, delivered via pipeline and LNG import facilities, constituted only 8 percent of total U.S. natural gas consumption (1.9 Tcf), the lowest proportion since 1993.[22] Of this amount, about 90 percent came from Canada.[23] (By contrast, 45 percent of U.S. oil consumption was imported in 2011, of which 29 percent came from Canada.[24]) Net imports of natural gas have decreased by 31 percent since 2007, with U.S. production growing significantly faster than U.S. demand. These trends and greater confidence in U.S. domestic gas supply suggest that prices between crude oil and gas will continue to diverge, establishing a new relationship that may fundamentally change the way energy sources are used in the United States.

THE RISE OF AN INTEGRATED GLOBAL MARKET

Although most of the world's gas supply continues to be transported regionally via pipeline, the global gas trade is accelerating because of the growing use of LNG. Natural gas, once liquefied,[25] can be transported

FIGURE 7: Trends in U.S. Natural Gas Consumption by Sector, 2000 to 2010



Source: Energy Information Administration, "Natural Gas Consumption by End Use," 2013. Available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

by tanker to distant destinations and regasified for use. Between 2005 and 2010, the global market for LNG grew by more than 50 percent,[26] and LNG now accounts for 30.5 percent of global gas trade.[27] From 2009 to 2011 alone, global capacity for gas liquefaction increased by almost 40 percent, with global LNG trade set to rise by 30 percent by 2017.[28]

In the United States, prospects for exports of LNG depend heavily on the cost-competitiveness of U.S. liquefaction projects relative to those at other locations. During 2000 to 2010, new investments were made in the United States in infrastructure for natural gas importation and storage, prompted by lower supply expectations and higher, volatile domestic prices. Since 2000, North America's import capacity for LNG has expanded from approximately 2.3 billion cubic feet (Bcf) per day to 22.7 Bcf per day, around 35 percent of the United States' average daily requirement.[29] However by 2012, U.S. consumption of imported LNG had fallen to less than 0.5 Bcf per day, leaving most of this capacity unused.[30] The ability to make use of and repurpose existing U.S. import infrastructure—pipelines, processing plants, and storage and loading facilities—would help reduce total costs relative to "greenfield," or new, LNG facilities. Given natural gas surpluses in the United States and substantially higher prices in other regional markets, several U.S. companies have applied for export authority and have indicated plans to construct liquefaction facilities.[31]

The EIA projects that the United States will become a net exporter of LNG in 2016, a net pipeline exporter in 2025, and a net exporter of natural gas overall in 2021. This outlook assumes continuing increases in use of LNG internationally, strong domestic natural gas production, and relatively low domestic natural gas prices.[32] In contrast, a study done by the Massachusetts Institute of Technology presents another possible scenario in which a more competitive international gas market could drive the cost of U.S. natural gas in 2020 above that of international markets, which could lead to the United States importing 50 percent of its natural gas by 2050.[33] Yet while increased trade in LNG has started to connect international markets, these markets remain largely distinct with respect to supply, contract structures, market regulation, and prices.

The increase in domestic production (supplies) of natural gas, low prices, and forecasts of continued low prices have not gone unnoticed. The implications for energy consumption are far-reaching and extend across all sectors of the economy. This report examines how each sector may take advantage of this energy transformation and evaluates the greenhouse gas emission implications of each case.

II. PRICE EFFECTS OF THE LOOMING NATURAL GAS TRANSITION

By Michael Webber, The University of Texas at Austin

INTRODUCTION

Given technology developments that have fundamentally altered the profile of U.S. natural gas production and recent low prices that have pushed demand for natural gas in all sectors of the economy, the importance of natural gas relative to other fuels is growing. If recent trends continue, it seems likely that natural gas will overtake petroleum as the most-used primary energy source in the United States. in the next one to two decades.

Such a transition will be enabled (or inhibited) by a mixed set of competing price pressures and a complicated relationship with lower-carbon energy sources that will trigger an array of market and cultural responses. This chapter seeks to layout some of the key underlying trends while also identifying some of these different axes of price tensions (or price dichotomies). These trends and price tensions will impact the future use of natural gas in all of the sectors analyzed later in this report.

NATURAL GAS COULD BECOME DOMINANT IN THE UNITED STATES WITHIN ONE TO TWO DECADES

For a century, oil and natural gas consumption trends have tracked each other quite closely. Figure 1 shows normalized U.S. oil and gas consumption from 1920 to 2010 (consumption in 1960 is set to a value of 1.0). These normalized consumption curves illustrate how closely oil and gas have tracked each other up until 2002, at which time their paths diverged: natural gas consumption declined from 2002 to 2006, while petroleum use grew over that time period. Then, they went the other direction: natural gas consumption grew and oil production dropped. That trend continues today, as natural gas pursues an upward path, whereas petroleum is continuing a downward trend.

The growing consumption of natural gas is driven by a few key factors:

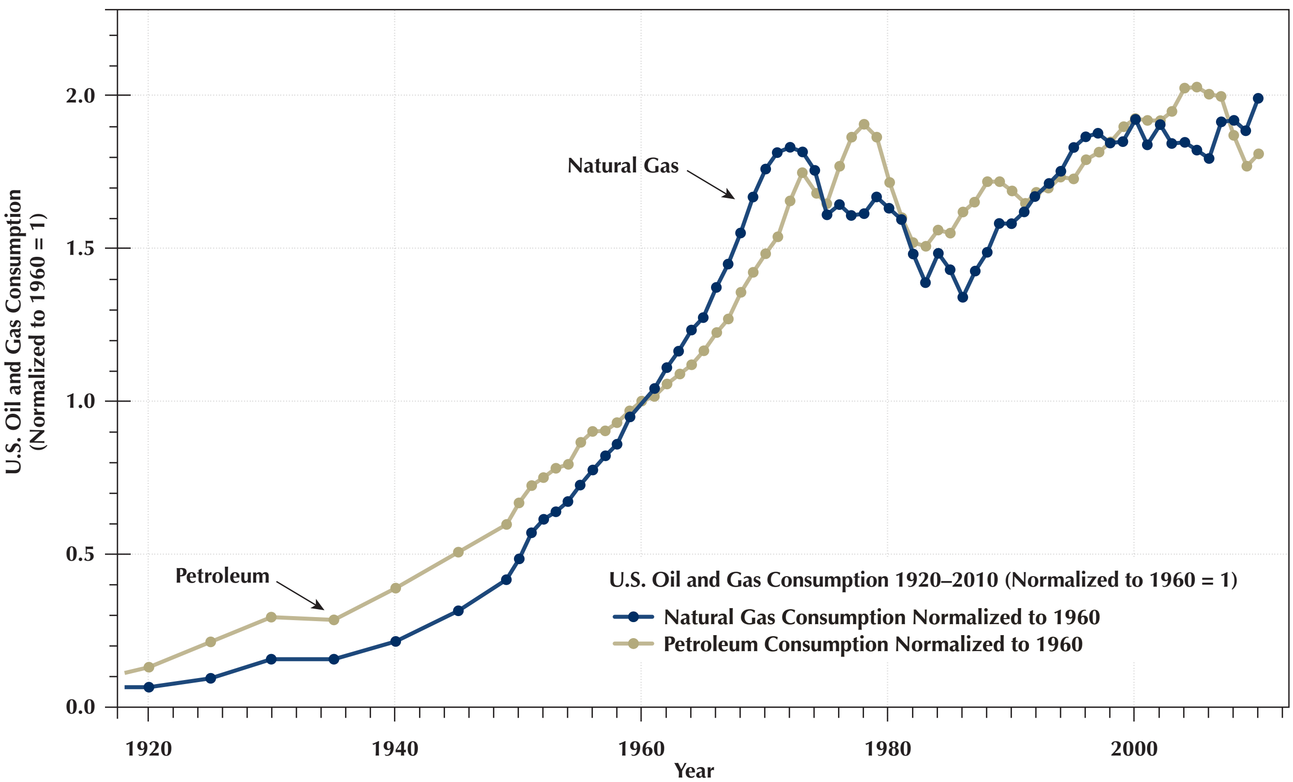
1. It has flexible use across many sectors, including direct use on-site for heating and power; use at power plants; use in industry; and growing use in transportation.
2. It has lower emissions (of pollutants and greenhouse gases) per unit of energy than coal and petroleum
3. It is less water-intensive than coal, petroleum, nuclear, and biofuels
4. Domestic production meets almost all of the annual U.S. consumption

By contrast, the trends for petroleum and coal are moving downwards. Petroleum use is expected to drop as a consequence of price pressures and policy mandates. The price pressures are triggered primarily by the split in energy prices between natural gas and petroleum (discussed in detail below). The mandates include biofuels production targets (which increase the production of an alternative to petroleum) and fuel economy standards (which decrease the demand for liquid transportation fuels). At the same time, coal use is also likely to drop because of projections by the EIA for price doubling over the next 20 years and environmental standards that are expected to tighten the tolerance for emissions of heavy metals, sulfur oxides, nitrogen oxides, particulate matter, and CO_2.

Petroleum use might decline 0.9 percent annually from the biofuels mandates themselves. Taking that value as the baseline, and matching it with an annual growth of 0.9 percent in natural gas consumption (which is a conservative estimation based on trends from the last six years, plus recent projections for increased use of natural gas by the power and industrial sectors), indicates that natural gas will surpass petroleum in 2032, two decades from now, as depicted in Figure 2. A steeper projection of 1.8 percent annual declines in petroleum matched with 1.8 percent annual increase in natural gas consumption sees a faster transition, with natural gas surpassing petroleum in less than a decade.

While such diverging rates might seem aggressive, they are a better approximation of the trends over the

FIGURE 1: **U.S. Oil and Gas Consumption, 1920 to 2010**



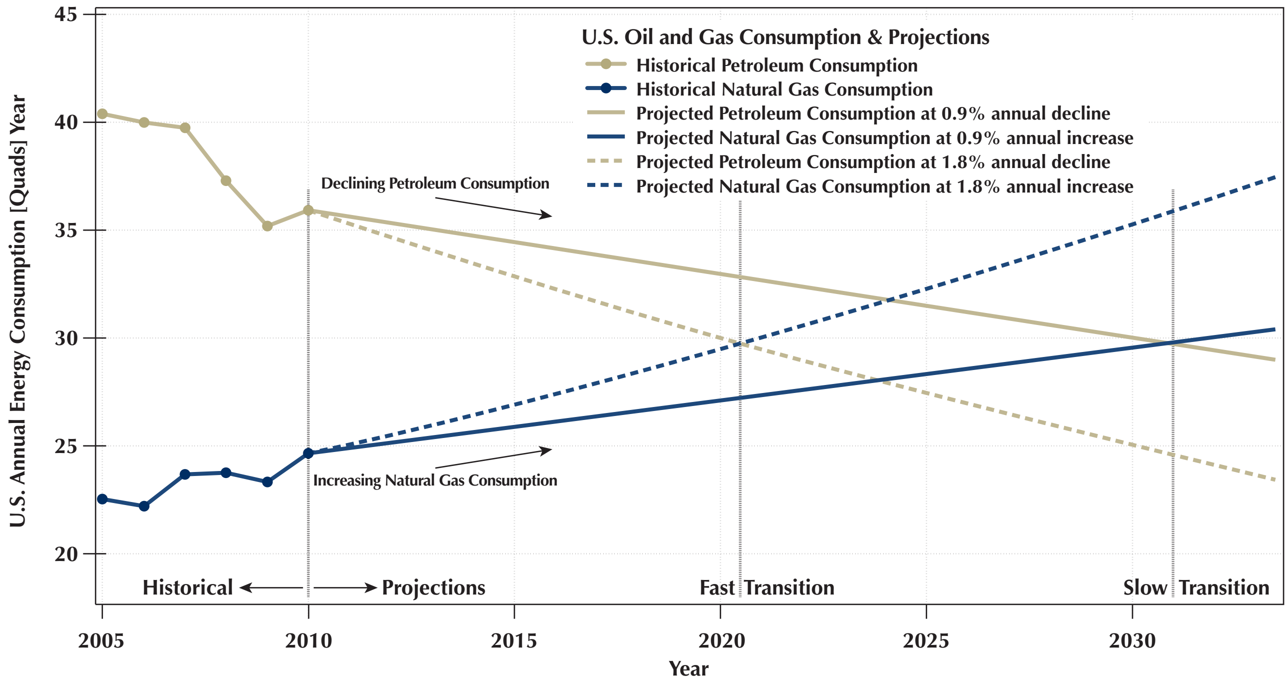
Source: Energy Information Agency, "Annual Energy Review 2010" Technical Report, 2011.

Note: U.S. oil and gas consumption from 1920 to present day (normalized to a value of 1 in 1960) shows how oil and gas have tracked each other relatively closely until 2002, after which their paths diverge. Since 2006, natural gas consumption has increased while petroleum consumption has decreased.

last six years than the respective 0.9 percent values. An annual decline in petroleum of 1.8 percent is plausible through a combination of biofuels mandates (0.9 percent annual decline), higher fuel economy standards (0.15 percent annual decline), and price competition that causes fuel-switching from petroleum to natural gas in the transportation (heavy-duty, primarily) and industrial sectors (0.75 percent annual decline). Natural gas growth rates of 1.8 percent annually can be achieved by natural gas displacing 25 percent of diesel use (for on-site power generation and transportation) and natural gas combined-cycle power plants displacing 25 percent of 1970s and 1980s vintage coal-fired power plants by 2022. While this scenario is bullish for natural gas, it is not implausible, especially for the power sector, whose power plants face retirement and stricter air quality standards. Coupling those projections with reductions in per-capita energy use of 10 percent (less than 1 percent annually) over that same span imply that total energy use would stay the same.

These positive trends for natural gas are not to say it is problem-free. Environmental challenges exist for water, land, and air. Water challenges are related to quality (from risks of contamination) and quantity (from competition with local uses and depletion of reservoirs). Land risks include surface disturbance from production activity and induced seismicity from wastewater reinjection. Air risks are primarily derived from leaks on site, leaks through the distribution system, and flaring at the point of production. Furthermore, while natural gas prices have been relatively affordable and stable in the last few years, natural gas prices have traditionally been very volatile. However, if those economic and environmental risks are managed properly, then these positive trends are entirely possible.

FIGURE 2: U.S. Oil and Gas Consumption and Projections



Source: Energy Information Agency, "Annual Energy Review 2010" Technical Report, 2011.

Note: Natural gas might pass petroleum as the primary fuel source in the United States within one to two decades, depending on the annual rate of decreases in petroleum consumption and increases in natural gas consumption. Historical values plotted are from EIA data.

THERE ARE SIX PRICE DICHOTOMIES WITH NATURAL GAS

In light of the looming transition to natural gas as the dominant fuel in the United States, it is worth contemplating the complicated pricing relationship that natural gas in the United States has with other fuels, market factors, and regions. It turns out that there are several relevant price dichotomies to keep in mind:

1. Natural Gas vs. Petroleum Prices,
2. U.S. vs. Global Prices,
3. Prices for Abundant Supply vs. Prices for Abundant Demand,
4. Low Prices for the Environment vs. High Prices for the Environment,
5. Stable vs. Volatile Prices, and
6. Long-Term vs. Near-Term Prices.

The tensions along these price axes will likely play an important role in driving the future of natural gas in the United States and globally.

DECOUPLING OF NATURAL GAS AND PETROLEUM PRICES

One of the most important recent trends has been the decoupling of natural gas and petroleum prices. Figure 3 shows the U.S. prices for natural gas and petroleum (wellhead and the benchmark West Texas Intermediate (WTI) crude at Cushing, Oklahoma respectively) from 1988 to 2012.[34, 35] While natural gas and petroleum prices have roughly tracked each other in the United States for decades, their trends started to diverge in 2009 as global oil supplies remained tight, yet shale gas production increased. This recent divergence has been particularly stark, as it's driven by the simultaneous downward swing in natural gas prices and upward swing in petroleum prices. For many years, the ratio in prices (per million BTU, or MMBTU) between petroleum and natural gas oscillated nominally in the range of 1–2, averaging 1.6 for 2000–2008. However, after the divergence began in 2009, this spread became much larger, averaging 4.2 for 2011 and, remarkably, achieving ratios greater than 9 spanning much of the first quarter of 2012 (for example, natural gas costs approximately $2/MMBTU today, whereas petroleum costs $18/MMBTU).

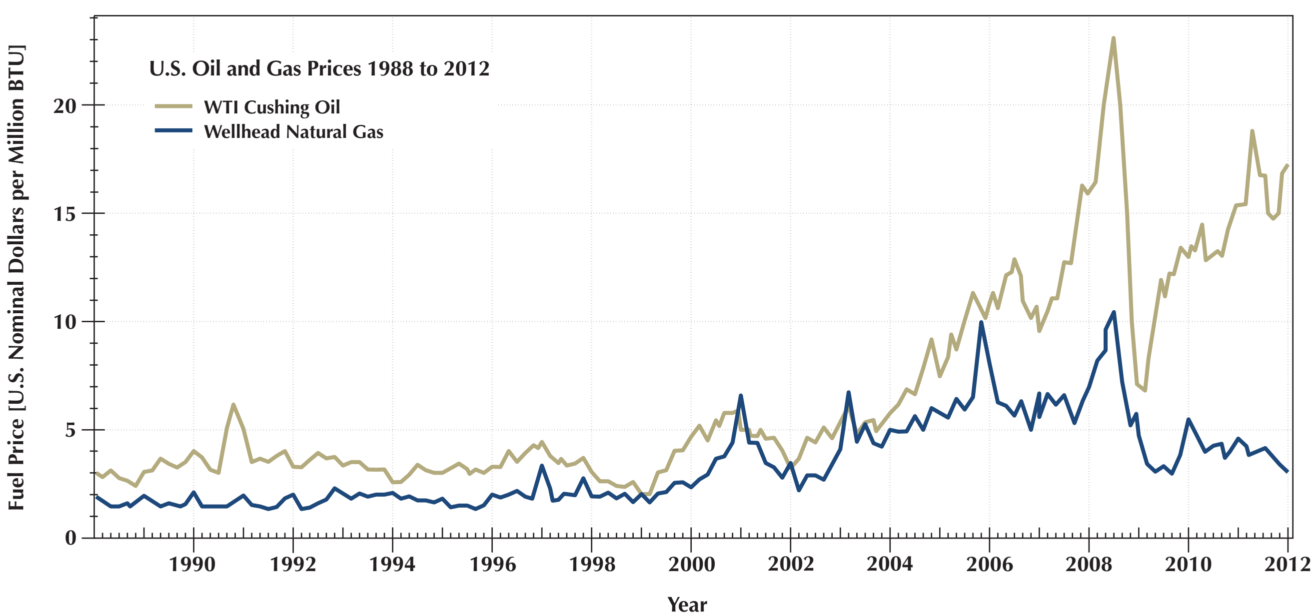
This spread is relatively unprecedented and, if sustained, opens up new market opportunities for gas to compete with oil through fuel-switching by end-users and the construction of large-scale fuel processing facilities. For the former, these price spreads might inspire institutions with large fleets of diesel trucks (such as municipalities, shipping companies, etc.) to consider investing in retrofitting existing trucks or ordering new trucks that operate on natural gas instead of diesel to take advantage of the savings in fuel costs. For the latter, energy companies might consider investing in multi-billion dollar gas-to-liquids (GTL) facilities to convert the relatively inexpensive gas into relatively valuable liquids.

DECOUPLING OF U.S. AND GLOBAL PRICES

Another important trend has been the decoupling of U.S. and global prices for natural gas. Figure 4 shows the U.S. prices for natural gas (at Henry Hub) compared with European Union and Japanese prices from 1992 to 2012.[36, 37, 38, 39] In a similar fashion as discussed below, while natural gas prices in the U.S. and globally (in particular, the European Union and Japan) have tracked each other for decades, their price trends started to diverge in 2009 because of the growth in domestic gas production. In fact, from 2003–2005, U.S. natural gas prices were higher than in the EU and Japan because of declining domestic production and limited capacity for importing liquefied natural gas (LNG). At that time, and for the preceding years, the U.S. prices were tightly coupled to global markets through its LNG imports setting the marginal price of gas.

Consequently, billions of dollars of investments were made to increase LNG import capacity in the United States That new import capacity came online concurrently with higher domestic production, in what can only be described as horribly ironic timing: because domestic production grew so quickly, those new imports were no longer necessary, and much of that importing capacity remains idle today. In fact, once production increased in 2009, the United States was then limited by its capacity to export LNG (which is in contrast to the situation just a few years prior, during which the United States was limited by its capacity to import gas), so gas prices plummeted despite growing global demand. Thus, while the United States was tightly coupled to global gas markets

FIGURE 3: U.S. Oil and Gas Prices, 1988 to 2012



Sources: Energy Information Administration, U.S. Natural Gas Prices, Tech. rep., April 2, 2012. Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm

Energy Information Administration, Cushing, OK WTI Spot Price FOB (Dollars per Barrel), Tech. rep., April 4, 2012. Available at: http://tonto.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M

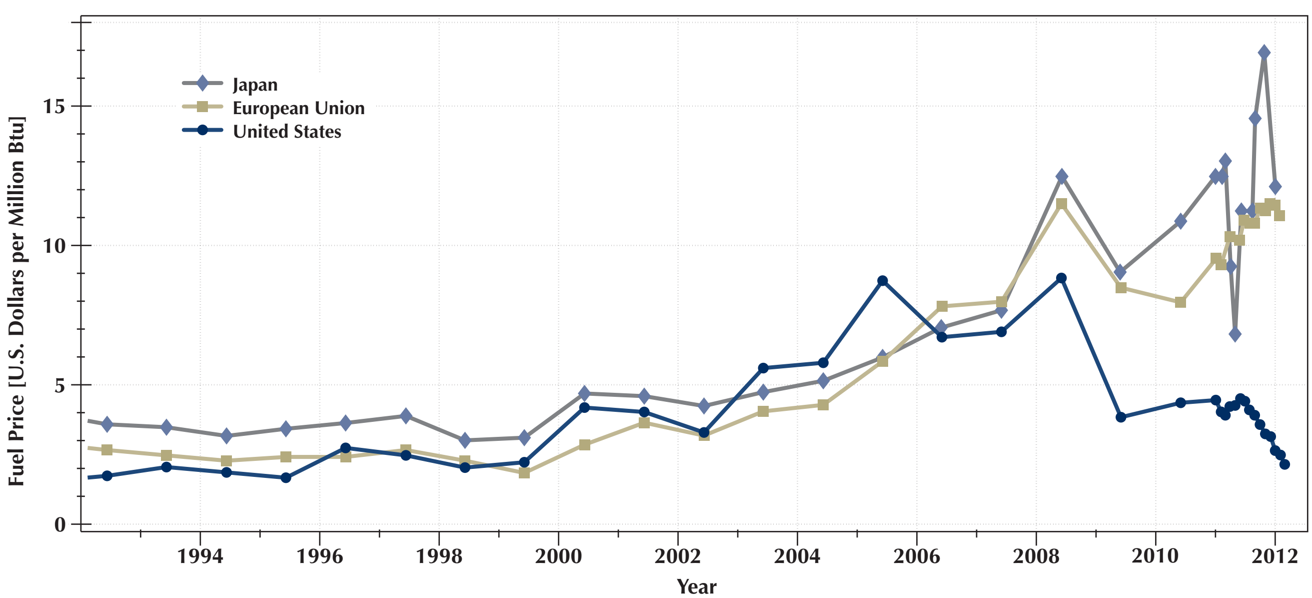
Note: While natural gas and petroleum prices have roughly tracked each other in the U.S. for decades, their price trends started to diverge in 2009.

for well over a decade, it has been decoupled for the last several years. At the same time, the European Union and Japan are tightly coupled to the world gas markets, (with the European Union served by LNG and pipelines from the Former Soviet Union, and Japan served by LNG). How long these prices remain decoupled will depend on U.S. production of natural gas, U.S. demand for natural gas, and the time it takes for these isolated markets to connect again. In fact, LNG terminal operators are now considering the investment of billions of dollars to turn their terminals around so that they can buy cheap natural gas in the U.S. that they can sell at higher prices to the EU and Japan. Once those terminals are turned around, these geographically-divergent market prices could come back into convergence.

PRICES FOR ABUNDANT SUPPLY VS. PRICES FOR ABUNDANT DEMAND

Another axis to consider for natural gas prices is the tension between the price at which we have abundant supply, and the price at which we have abundant demand. These levels have changed over the years as technology improves and the prices of competing fuels have shifted, but it seems clear that there is still a difference between the prices that consumers wish to pay and producers wish to collect. In particular, above a certain price (say, somewhere in the range of $4–8/MMBTU, though there is no single threshold that everyone agrees upon), the United States would be awash in natural gas. Higher prices make it possible to economically produce many marginal plays, yielding dramatic increases in total production. However, at those higher prices, the demand for gas is relatively lower because cheaper alternatives (nominally coal, wind, nuclear and petroleum) might be more attractive options. At the same time, as recent history has demonstrated, below a certain price (say, somewhere in the range of $1–3/MMBTU), there is significant demand for natural gas in the power sector (as an alternative to coal) and the industrial sector (because of revitalized chemical manufacturing, which depends heavily on natural gas as a feedstock). Furthermore, if prices are expected to remain low, then demand for natural gas would increase in the residential and commercial sectors (as an alternative

FIGURE 4: Natural Gas Prices in Japan, the European Union and the United States, 1992 to 2012



Sources: BP, "BP Statistical Review of World Energy," Tech. rep., June 2011, Available at: bp.com/statisticalreview

Energy Information Administration, Henry Hub Gulf Coast Natural Gas Spot Price, Tech. rep., April 6, 2012. Available at: http://tonto.eia.gov/dnav/ng/hist/rngwhhdm.htm

Energy Information Administration, Price of Liquefied U.S. Natural Gas Exports to Japan, Tech. rep., April 6, 2012. Available at: http://www.eia.gov/dnav/ng/hist/n9133ja3m.htm

YCharts, European Natural Gas Import Price, Tech. rep., April 6, 2012. Available at: http://ycharts.com/indicators/europe_natural_gas_price

Note: While natural gas prices in the U.S. and globally (EU and Japan) have tracked each other for decades, their price trends started to diverge in 2009.

to electricity for water heating, for example) and in the transportation sector (to take advantage of price spreads with diesel, as noted above).

The irony here is that it is not clear that the prices at which there will be significant increases in demand will be high enough to justify the higher costs that will be necessary to induce increases in supply, and so there might be a period of choppiness in the market as the prices settle into their equilibrium. Furthermore, as global coal and oil prices increase (because of surging demand from China and other rapidly-growing economies), the thresholds for this equilibrium are likely to change. As oil prices increase, natural gas production will increase at many wells as a byproduct of liquids production, whether the gas was desired or not. Since the liquids are often used to justify the costs of a new well, the marginal cost of the associated gas production can be quite low. Thus, natural gas production might increase even without upward pressure from gas prices, which lowers the price threshold above which there will be abundant supply. At the same time, coal costs are increasing globally, which raises the threshold below which there is abundant demand. Hopefully, these moving thresholds will converge at a stable medium, though it is too early to tell. If the price settles too high, then demand might retract; if it settles too low, the production might shrink, which might trigger an oscillating pattern of price swings.

LOW PRICES FOR THE ENVIRONMENT VS. HIGH PRICES FOR THE ENVIRONMENT

Another axis of price tension for natural gas is whether high prices or low prices are better for achieving environmental goals such as reducing the energy sector's emissions and water use. In many ways, high natural gas prices have significant environmental advantages because they induce conservation and enable market penetration by relatively expensive renewables. In particular, because it is common for natural gas to be the next fuel source dispatched into the power grid in the United States, high natural gas prices trigger high electricity prices. Those higher electricity prices make it easier for renewable energy sources such as wind and solar power to compete in the markets. Thus, high natural gas prices are useful for reducing consumption overall and for spurring growth in novel generation technologies.

However, inexpensive natural gas also has important environmental advantages by displacing coal in the power sector. Notably, by contrast with natural gas prices, which have decreased for several years in a row, prevailing coal prices have increased steadily for over a decade due to higher transportation costs (which are coupled to diesel prices that have increased over that span), depletion of mines, and increased global demand. As coal prices track higher and natural gas prices track lower, natural gas has become a more cost-effective fuel for power generation for many utility companies. Consequently, coal's share of primary energy consumption for electricity generation has dropped from 53 percent in 2003 to less than 46 percent in 2011 (with further drops in the first quarter of 2012), while the share fulfilled by natural gas grew from 14 percent to 20 percent over the same span. At the same time, there was a slight drop in overall electricity generation due to the economic recession, which means the rise of natural gas came at the expense of coal, rather than in addition to coal. Consequently, for those wishing to achieve the environmental goals of dialing back on power generation from coal, low natural gas prices have a powerful effect.

These attractive market opportunities are offset in some respects by the negative environmental impacts that are occurring from production in the Bakken and Eagle Ford shale plays in North Dakota and Texas. At those locations, significant volumes of gases are flared because the gas is too inexpensive to justify rapid construction of the pricey distribution systems that would be necessary to move the fuel to markets.[40, 41] Consequently, for many operators it ends up being cheaper in many cases to flare the gas rather than to harness and distribute it.

And, thus, the full tension between the "environmental price" of gas is laid out: low prices are good because they displace coal, whereas high prices are good because they bring forward conservation and renewable alternatives. This price axis will be important to watch from a policymaker's point of view as time moves forward.

STABLE VS. VOLATILE PRICES

One of the historical criticisms of natural gas has been its relative volatility, especially as compared with coal and nuclear fuels, which are the other major primary energy sources for the power sector. This volatility is a consequence of large seasonal swings in gas consumption (for example, for space and water heating in the winter) along with the association of gas production with oil, which is also volatile. Thus, large magnitude swings in demand and supply can be occurring simultaneously, but in opposing directions. However, two forces are mitigating this volatility. Firstly, because natural gas prices are decoupling from oil prices (as discussed in above), one layer of volatility is reduced. Many gas plays are produced independently of oil production. Consequently, there is a possibility for long-term supply contracts at fixed prices. Secondly, the increased use of natural gas consumption in the power sector, helps to mitigate some of the seasonal swings as the consumption of gas for heating in the winter might be better matched with consumption in the summer for power generation to meeting air conditioning load requirements.

Between more balanced demand throughout the year and long-term pricing, the prospects for better stability look better. At the same time, coal, which has historically enjoyed very stable prices, is starting to see higher volatility because its costs are coupled with the price of diesel for transportation. Thus, ironically, while natural gas is reducing its exposure to oil as a driver for volatility, coal is increasing its exposure.

LONG-TERM VS. NEAR-TERM PRICE

While natural gas is enjoying a period of relatively stable and low prices at the time of this writing, there are several prospects that might put upward pressure on the long-term prices. These key drivers are: 1) increasing demand, and 2) re-coupling with global markets.

As discussed above, there are several key forcing functions for higher demand. Namely, because natural gas is relatively cleaner, less carbon-intensive, and less water-intensive than coal, it might continue its trend of taking away market share from coal in the power sector to meet increasingly stringent environmental standards. While this trend is primarily driven by environmental constraints, its effect will be amplified as long as natural gas prices remain low. While fuel-switching in the power sector will likely have the biggest overall impact on new natural gas demand, the same environmental and economic drivers might also induce fuel-switching in the transportation sector (from diesel to natural gas), and residential and commercial sectors (from fuel oil to natural gas for boilers, and from electric heating to natural gas heating). If cumulative demand increases significantly from these different factors but supply does not grow in a commensurate fashion, then prices will move upwards.

The other factor is the potential for re-coupling U.S. and global gas markets. While they are mostly empty today, many LNG import terminals are seeking to reverse their orientation, with an expectation that they will be ready for export beginning in 2014. Once they are able to export gas to EU and Japanese markets, then domestic gas producers will have additional markets for their product. If those external markets maintain their much higher prevailing prices (similar to what is illustrated in Figure 4), re-coupling will push prices upwards.

Each of these different axes of price tensions reflects a different nuance of the complicated, global natural gas system. In particular, they exemplify the different market, technological and societal forces that will drive—and be driven by—the future of natural gas.

CONCLUSION

Overall, it is clear that natural gas has an important opportunity to take market share from other primary fuels. In particular, it could displace coal in the power sector, petroleum in the transportation sector, and fuel oil in the commercial and residential sectors. With sustained growth in demand for natural gas, coupled with decreases in demand for coal and petroleum because of environmental and security concerns, natural gas could overtake petroleum to be the most widely used fuel in the United States within one to two decades. Along the path towards that transition, natural gas will experience a variety of price tensions that are manifestations of the different market, technological and societal forces that will drive—and be driven by— the future of natural gas. How and whether we sort out these tensions and relationships will affect the fate of natural gas and are worthy of further scrutiny.

III. GREENHOUSE GAS EMISSIONS AND REGULATIONS ASSOCIATED WITH NATURAL GAS PRODUCTION

By Joseph Casola, Daniel Huber, and Michael Tubman, C2ES

INTRODUCTION

Natural gas is a significant source of greenhouse gas emissions in the United States. Approximately 21 percent of total U.S. greenhouse gas emissions in 2011 were attributable to natural gas.[42] When natural gas is combusted for energy, it produces carbon dioxide (CO_2), which accounts for most of greenhouse gas emissions associated with this fuel. Natural gas is composed primarily of methane (CH_4), which has a higher global warming potential than CO_2. During various steps of natural gas extraction, transportation, and processing, methane escapes or is released to the atmosphere. Although this represents a relatively smaller portion of the total greenhouse gas emissions associated with natural gas production and use, vented and leaked or "fugitive" emissions can represent an opportunity to reduce greenhouse gas emissions, maximizing the potential climate benefits of using natural gas.

Total methane emissions from natural gas systems (production, processing, storage, transmission, and distribution) in the United States have improved during the last two decades, declining 13 percent from 1990 to 2011, driven by infrastructure improvements and technology, as well as better practices adopted by industry. This has occurred even as production and consumption of natural gas has grown. Methane emissions per unit of natural gas consumed have dropped 32 percent from 1990 to 2011. Since 2007, methane emissions from all sources have fallen almost 6 percent, driven primarily by reductions of methane emissions from natural gas systems. Nevertheless, given its impact on the climate, emphasis on reducing methane emissions from all sources must remain a high priority. This chapter discusses the differences between methane and CO_2, emission sources, and state and federal regulations affecting methane emissions.

GLOBAL WARMING POTENTIALS OF METHANE AND CO_2

On a per-mass basis, methane is more effective at warming the atmosphere than CO_2. This is represented by methane's global warming potential (GWP), which is a factor that expresses the amount of heat trapped by a pound of a greenhouse gas relative to a pound of CO_2 over a specified period of time. GWP is commonly used to enable direct comparisons between the warming effects of different greenhouse gases. By convention, the GWP of CO_2 is equal to one.

The GWP of a greenhouse gas (other than CO_2) can vary substantially depending on the time period of interest. For example, on a 100-year time frame, the GWP of methane is about 21.[43] But for a 20-year time frame, the GWP of methane is 72.[44] The difference stems from the fact that the lifetime of methane in the atmosphere is relatively short, a little over 10 years, when compared to CO_2, which can persist in the atmosphere for decades to centuries.

Since models that project future climate conditions are often compared for the target year of 2100, it is often convenient to use 100-year GWPs when comparing emissions of different greenhouse gases. However, these comparisons may not accurately reflect the relative reduction in radiative forcing (the extent to which a gas traps heat in the atmosphere) arising from near-term abatement efforts for greenhouse gases with short lifetimes. Whereas near-term reductions in CO_2 emissions provide reductions in radiative forcing benefits spread out over a century, near-term abatement efforts for methane involve a proportionally larger near-term reduction in radiative forcing. In light of potential climate change over the next 50 years, the control of methane has an importance that can be obscured when greenhouse gases are compared using only their 100-year

GWPs. Accordingly, reducing methane emissions from all sources is important to efforts aimed at slowing the rate of climate change.

EMISSIONS FROM NATURAL GAS COMBUSTION

On average, natural gas combustion releases approximately 50 percent less CO_2 than coal and 33 percent less CO_2 than oil (per unit of useful energy) (Figure 1). In addition, the combustion of coal and oil emits other hazardous air pollutants, such as sulfur dioxides and particulate matter. Therefore, the burning of natural gas is considered cleaner and less harmful to public health and the environment than the burning of coal and oil.

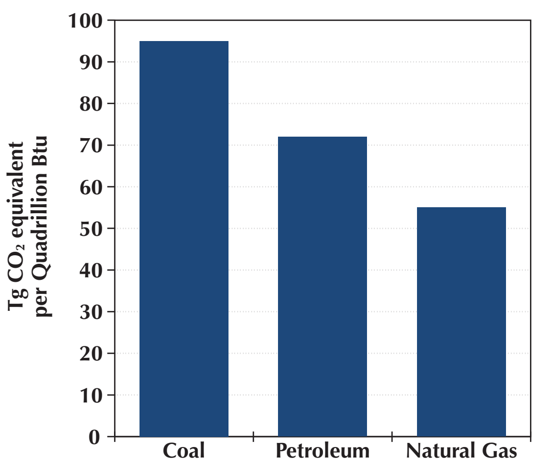
The U.S. Energy Information Administration (EIA) has projected that U.S. energy-related CO_2 emissions will remain more than 5 percent below their 2005 level through 2040, a projection based in large part on the expectation that: 1) natural gas will be steadily substituted for coal in electricity generation as new natural gas power plants are built and coal-fired power plants are converted to natural gas, and 2) state and federal programs that encourage the use of low-carbon technologies will continue.[45] The EIA predicts that natural gas—fired electricity production in the United States will increase from 25 percent in 2010 to 30 percent in 2040, in response to continued low natural gas prices and existing air quality regulations that affect coal-fired power generation.

VENTING AND LEAKED EMISSIONS ASSOCIATED WITH NATURAL GAS PRODUCTION

In 2011, natural gas systems contributed approximately one-quarter of all U.S. methane emissions (Figure 2), of which over 37 percent are associated with production.[46] In the production process, small amounts of methane can leak unintentionally. In addition methane may be intentionally released or vented to the atmosphere for safety reasons at the wellhead or to reduce pressure from equipment or pipelines. Where possible, flares can be installed to combust this methane (often at the wellhead), preventing much of it from entering the atmosphere as methane but releasing CO_2 and other air pollutants instead.

These methane emissions are an important, yet not well understood, component of overall methane emissions. In recent years greenhouse gas measurement and reporting requirements have drawn attention to the need for more accurate data. This uncertainty can be seen in the revisions that have accompanied sector emission

FIGURE 1: CO_2 Emissions from Fossil Fuel Combustion

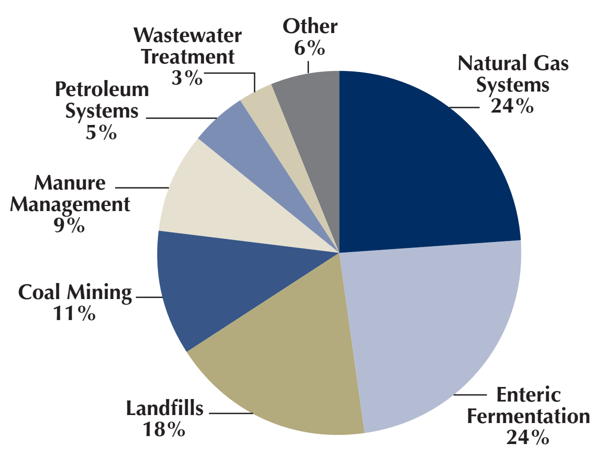


Source: Environmental Protection Agency, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011. 2013. Chapter 3 and Annex 2. Available at: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

Notes: CO_2 content for petroleum has been calculated as an average of representative fuel types (e.g., jet fuel, motor gasoline, distillate fuel) using 2011 data.

This graphic does not account for the relative efficiencies of end-use technologies.

FIGURE 2: Sources of Methane Emissions in the United States, 2011



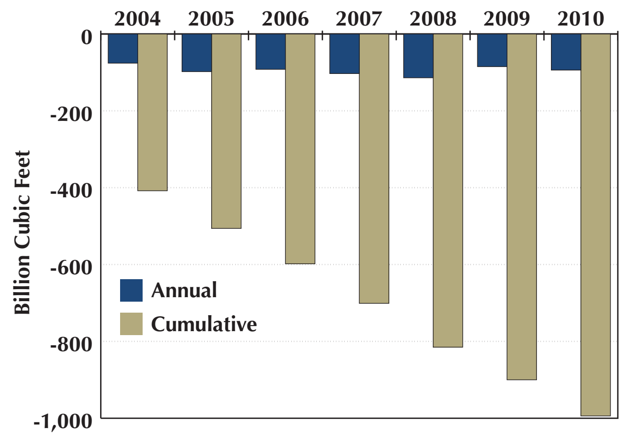
Source: Environmental Protection Agency, Draft U.S. Greenhouse Gas Inventory Report, 2013. Available at: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html estimates. Just recently for example, EPA revised downward the estimated level of methane emissions attributable to production of natural gas. In 2010, it estimated about 58 percent of methane emission in the natural gas system came from production. In 2013, EPA reduced that number to 37 percent. A major reason for this revision was a change in EPA's assumption about emission leakage rates. Based on EPA's GHG inventory data, the assumed leakage rate for the overall natural gas system was revised downward from 2.27 percent in 2012 to 1.54 percent in 2013.[47] Independent studies have estimated leak rates ranging from 0.71 to 7.9 percent.[48, 49, 50] EPA and others are trying to better understand the extent of leakage and where this leakage is occurring.

Given the climate implications of methane, considerable effort is also being focused on reducing leakage and methane emissions overall. According to EPA, methane emissions from U.S. natural gas systems have declined by 10 percent between 1990 and 2011 even with the expansion of natural gas infrastructure.[51] This decline is largely the result of voluntary reductions including greater operational efficiency, better leakage detection, and the use of improved materials and technologies that are less prone to leakage.[52] In particular, the EPA's Natural Gas Star Program has worked with the natural gas industry to identify technical and engineering solutions that minimize emissions from infrastructure, including zero-bleed pneumatic controllers, improved valves, corrosion-resistant coatings, dry-seal compressors, and improved leak-detection and leak-repair strategies. The EPA has tracked methane reductions associated with its Natural Gas STAR program (Figure 3) and estimates that voluntary actions undertaken by the natural gas sector reduced emissions by 94.1 billion cubic feet (Bcf) in 2010. Notably, many of the solutions identified by this voluntary program have payback periods of less than three years (depending on the price of natural gas).[53] The success of the Natural Gas STAR program further highlights the importance of understanding where emission leakage is occurring because without accurate data, it is difficult to prioritize reduction efforts or make the case for technologies and processes like those highlighted by the program.

REGULATION OF LEAKAGE AND VENTING

Regulations applicable to methane leakage and venting from natural gas operations have been implemented at both the federal and state level. Although air pollution

FIGURE 3: Annual and Cumulative Reductions in Methane Emissions Associated with the Environmental Protection Agency's Natural Gas STAR Program, 2004 to 2010



Source: Environmental Protection Agency, "Accomplishments," July 2012. Available at http://www.epa.gov/gasstar/accomplishments/index.html

from natural gas production has been regulated in various forms since 1985 (e.g., toxic substances such as benzene and volatile organic compounds that contribute to smog formation), over the past few years, due to the recent increase in natural gas production and the use of new extraction methods (particularly hydraulic fracturing), natural gas operations have come under renewed scrutiny from policy-makers, non-governmental organizations, and the general public. In response to potential environmental and climate impacts from increased natural gas production including deployment of new technologies, new state and national rules are being developed.

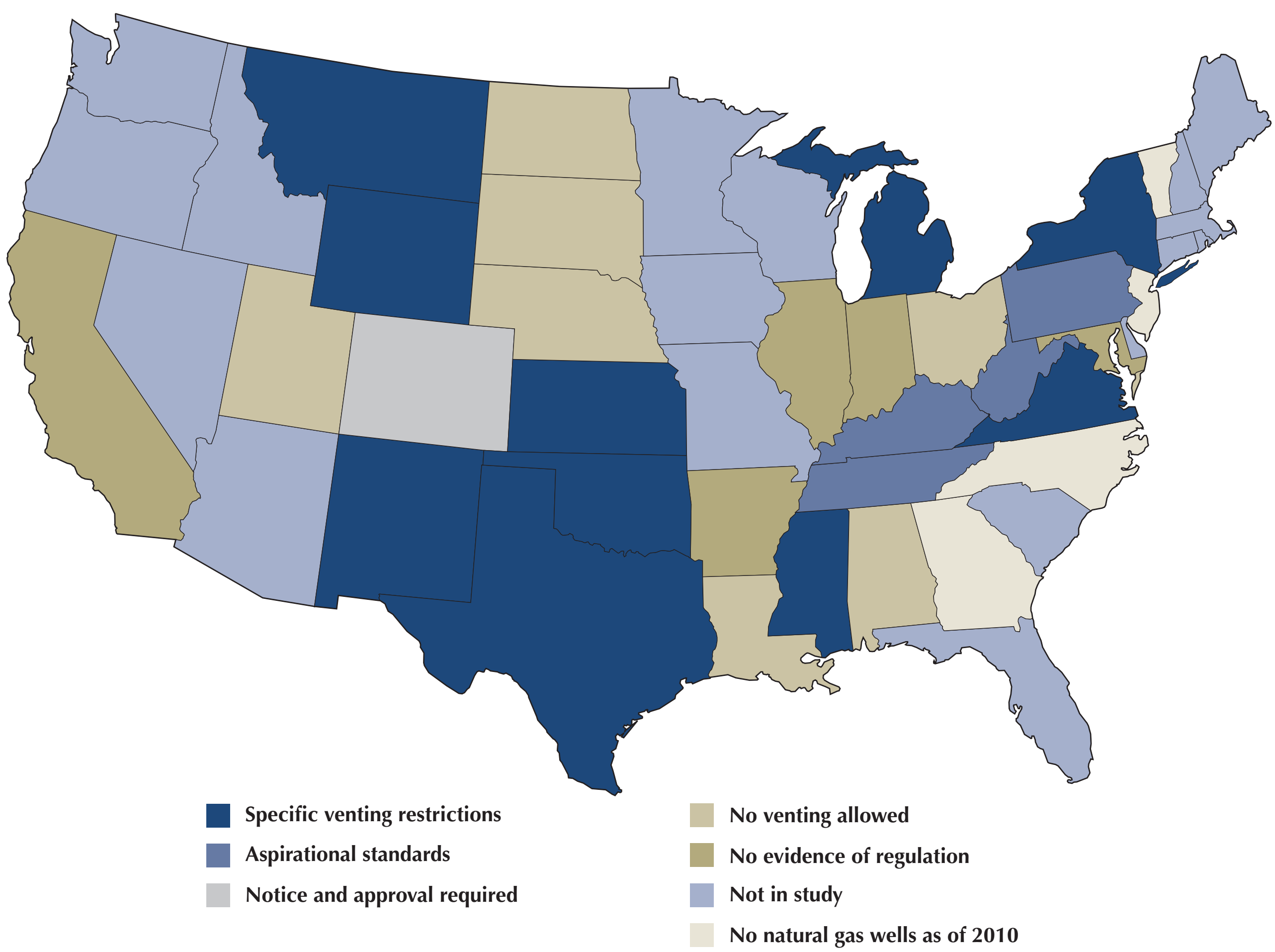
FEDERAL REGULATIONS

EPA released new air pollution standards for natural gas operations on August 16, 2012. The New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants are the first federal regulations to specifically require emission reductions from new or modified hydraulically fractured and refractured natural gas wells. The New Source Performance Standards require facilities to reduce emissions to a certain level that is achievable using the best system of pollution control, taking other factors into consideration, such as cost.[54] Under the National Emissions Standards for Hazardous Air Pollutants program, EPA sets technology-based standards for reducing certain hazardous air pollutant emissions using maximum achievable control technology. The regulations target the emission of volatile organic compounds, sulfur dioxide, and air toxics, but have the co-benefit of reducing emissions of methane by 95 percent from well completions and recompletions.[55]

Among several emission controls, these rules also require the use of "green completions" at natural gas drilling sites, a step already mandated by some jurisdictions and voluntarily undertaken by many companies. In a "green completion," special equipment separates hydrocarbons from the used hydraulic fracturing fluid, or "flowback," that comes back up from the well as it is being prepared for production. This step allows for the collection (and sale or use) of methane that may be mixed with the flowback and would otherwise be released to the atmosphere. The final "green completion" standards apply to hydraulically fractured wells that begin construction, reconstruction, or modification after August 23, 2011, estimated to be 11,000 wells per year. The "green completion" requirement will be phased-in over time, with flaring allowed as an alternative compliance mechanism until January 1, 2015.

While the "green completion" regulations are expected to reduce methane emissions from natural gas wells, concern has been expressed that the regulations do not apply to onshore wells that are not hydraulically

FIGURE 4: Venting Regulations by State

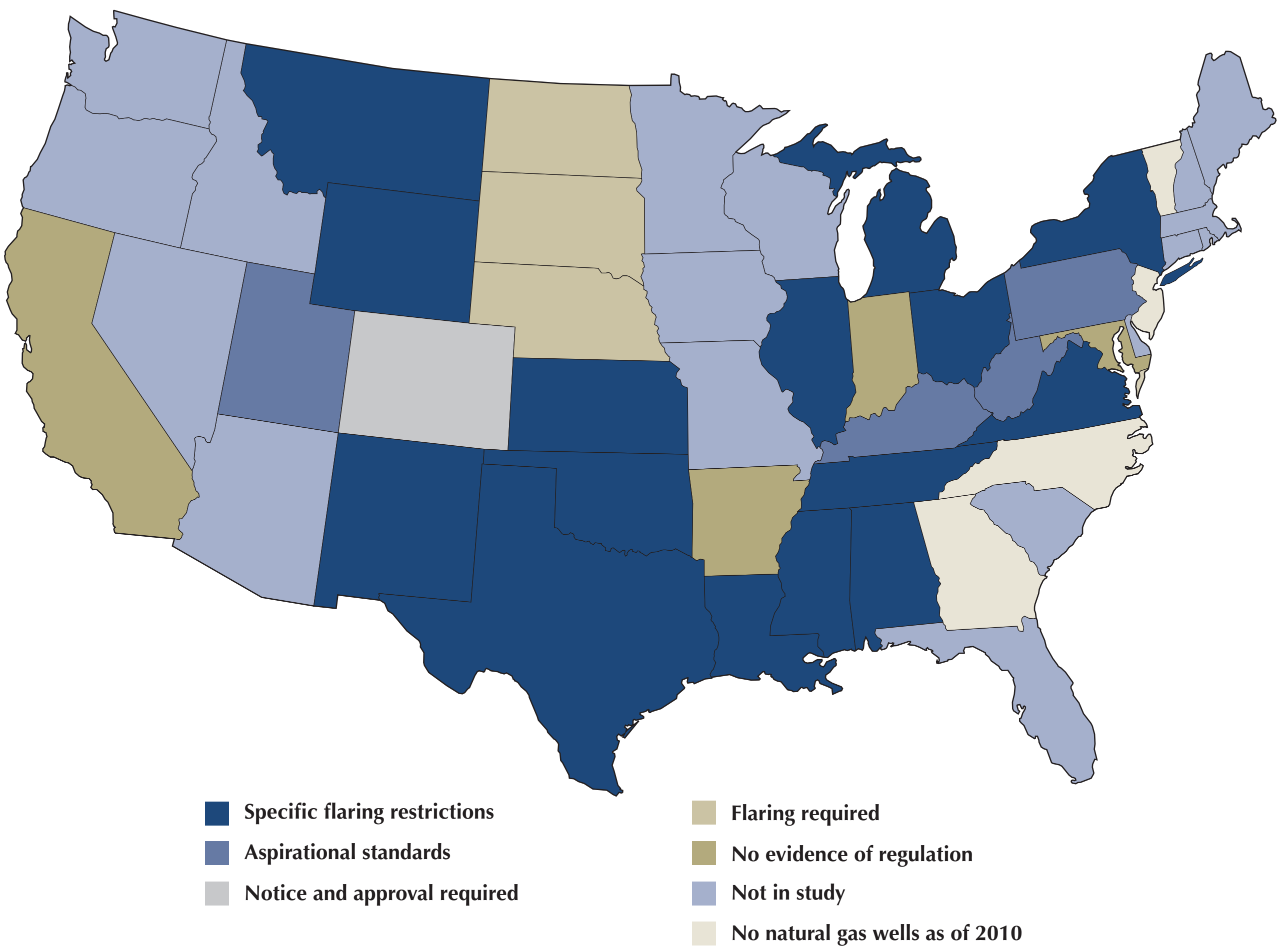


Source: Resources for the Future. "A Review of Shale Gas Regulations by State." July 2012. Available at: http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx fractured, existing hydraulically fractured wells until such time as they are refractured, or oil wells, including those that produce associated natural gas.[56] However, geologic and market barriers may limit the applicability of this type of rule to other sources of natural gas.

STATE REGULATIONS

Numerous states have also implemented regulations that address venting and flaring from natural gas exploration and production. Some states with significant oil and gas development, such as Colorado, North Dakota, Ohio, Pennsylvania, Texas, and Wyoming, already have venting and/or flaring requirements in place. For example, Ohio requires that all methane vented to the atmosphere be flared (with the exception of gas released by a properly functioning relief device and gas released by controlled venting for testing, blowing down, and cleaning out wells). North Dakota allows gas produced with crude oil from an oil well to be flared during a one-year period from the date of first production from the well. After that time period, the well must be capped or connected to a natural gas gathering line.[57] These regulations may be changed or upgraded as the national "green completion" rules come into effect. Maps produced by Resources for the Future, show the diversity of state regulations that apply to venting and flaring in natural gas development in 31 states (Figures 4 and 5).

FIGURE 5: Flaring Regulations by State



Source: Resources for the Future. "A Review of Shale Gas Regulations by State." July 2012. Available at: http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx

CONCLUSION

The climate implications associated with the production and use of natural gas differ from other fossil fuels (coal and oil). Natural gas combustion yields considerably lower emissions of greenhouse gases and other air pollutants; however, when methane is released directly into the atmosphere without being burned—through accidental leakage or intentional venting—it is about 21 times more powerful as a heat trapping greenhouse gas than CO_2 when considered on a 100-year time scale. As a result, considerable effort is underway to accurately measure methane emission and leakage. Policy-makers should continue to engage all stakeholders in a fact-based discussion regarding the quantity and quality of available emissions data and what steps can be taken to improve these data and accurately reflect the carbon footprint of all segments of the natural gas industry. To that end, additional field testing should be performed to gather up-to-date, accurate data on methane emissions. Policy-makers have begun to create regulations that address methane releases, but a better understanding and more accurate measurement of the emissions from natural gas production and use could potentially identify additional cost-effective opportunities for emissions reductions along the entire natural gas value chain.

IV. POWER SECTOR

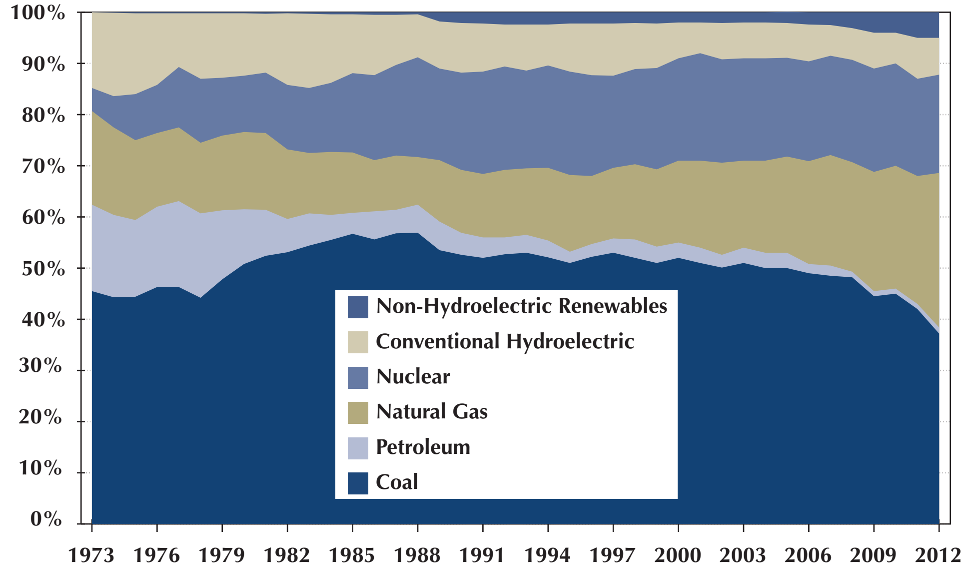
By Doug Vine, C2ES

INTRODUCTION

The U.S. power industry produces electricity from a variety of fuel sources (Figures 1 and 2). In 2012, coal-fueled generation provided a little more than 39 percent of all electricity, down from 50 percent in 2005. Nuclear power provided around 19 percent of net generation. Filling the gap left by the declining use of coal, natural gas now provides nearly 29 percent of all electricity and renewables, including wind and large hydroelectric power, provide about 12 percent. Petroleum-fueled generation is in decline, providing less than 1 percent of electricity in 2012.

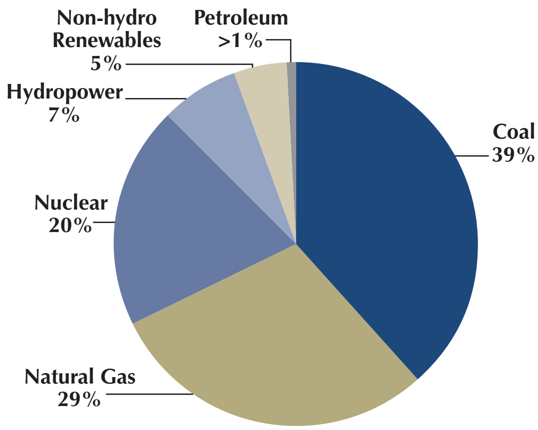
Natural gas use in the power sector during the 1970s and 1980s was fairly consistent and low, contributing a declining share of total electricity generation as coal and nuclear power's share of total electricity significantly increased. In 1978, in response to supply shortages (the result of government price controls), Congress enacted the Power Plant and Industrial Fuel Use Act.[58] The law prohibited the use of oil and natural gas in new industrial boilers and new power plants, with the goal of preserving the (thought to be) scarce supplies for residential customers.[59] As a consequence, the demand for natural gas declined during the 1980s, contributing to an oversupply of gas for much of the decade. The falling natural gas demand and prices spurred the repeal in 1987 of sections of the Fuel Use Act that restricted the use of natural gas by industrial users and electric utilities.[60] (For an overview of key policies impacting natural gas supply, see Appendix A). Continued low natural gas prices in the 1990s stimulated the rapid construction of gas-fired power plants.[61] In the early 2000s, the building boom in natural gas-fired generation was tempered

FIGURE 1: U.S. Electricity Generation by Fuel Type, 1973 to 2012



Source: Energy Information Administration, "Electricity Net Generation: Total (All Sectors). Table 7.2a," March 2013. Available at: http://www.eia.gov/totalenergy/data/monthly/#electricity

FIGURE 2: **U.S. Electricity Generation by Fuel Type, 2012**



Source: Energy Information Administration, "March 2013 Monthly Energy Review. Table 7.2b. Electricity Net Generation: Electric Power Sector," Available at: http://www.eia.gov/totalenergy/data/monthly/#electricity

somewhat by price spikes, although natural gas-fired generating capacity continues to be added more than any other fuel type. Since 1990, electricity generation from natural gas has increased from around 11 percent to 29 percent of the total net generation in 2012 (Figure 1). In 2006, natural gas surpassed nuclear power's share of the total generation mix, and in April 2012, natural gas and coal each contributed a little more than 32 percent of total generation.

This chapter explores the combination of factors driving change in the power sector. It examines the advantages and disadvantages of natural gas use, the competitive nature of alternative energy sources, and the synergy between natural gas and renewable energy generation. Finally, it explores relevant policy options that could lower greenhouse gas emissions in the sector.

ADVANTAGES AND DISADVANTAGES OF NATURAL GAS USE IN THE POWER SECTOR

From the perspective of an electrical system operator, a power plant owner, or an environmental perspective, natural gas-fueled power generation has many advantages. Natural gas can provide baseload, intermediate, and peaking electric power, and can thus meet all types of electrical demand. It is an inexpensive, reliable, dispatchable source of power that is capable of supplying firm backup to intermittent sources such as wind and solar.[62] Natural gas power plants can be constructed relatively quickly, in as little as 20 months.[63] Air emissions are significantly less than those associated with coal generation, and compared to other forms of electric generation, natural gas plants have a small footprint on the landscape. However, even though combustion of natural gas produces lower greenhouse gas emissions than combustion of coal or oil, natural gas does emit a significant amount of carbon dioxide (CO_2), and its direct release into the atmosphere, as discussed in chapter 3, adds quantities of a greenhouse gas many times more potent than CO_2. Finally, natural gas-fired power plants must be sited near existing natural gas pipelines, or else building new infrastructure may significantly increase their cost.

Cost of Building Natural Gas-Fired Power Plants

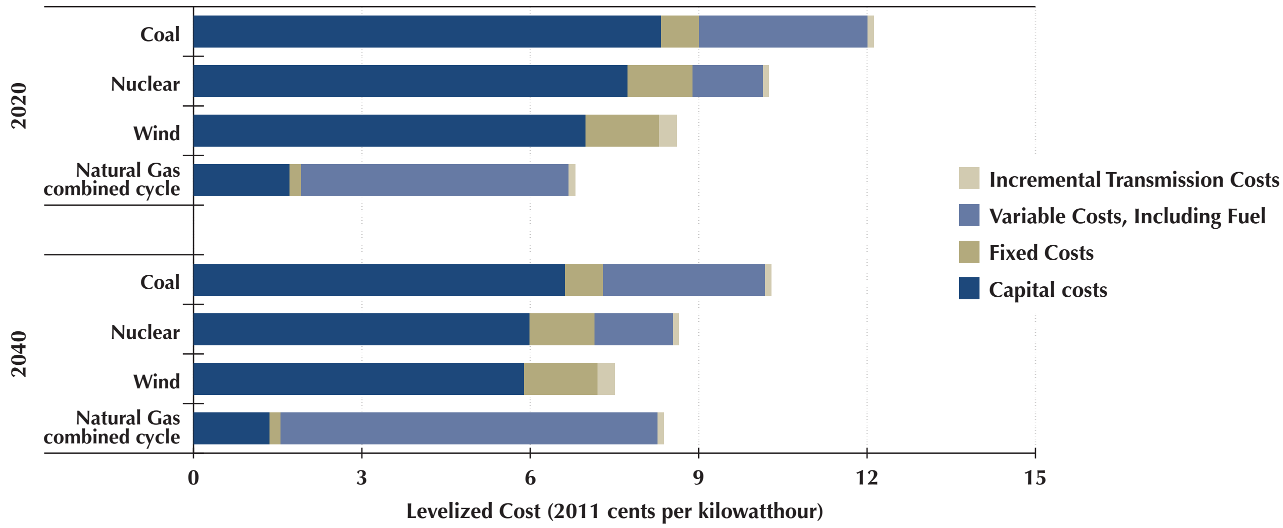
Natural gas-fired combined-cycle electricity generation (see Appendix B for a list of power plant technologies) is projected to be the least expensive generation technology in the near and mid-term, taking into account a range of costs over an assumed time period. These costs include capital costs, fuel costs, fixed and variable operation/maintenance costs, financing costs, and an assumed utilization rate for the type of generation plant (Figure 3). The availability of various incentives including state or federal tax credits can also impact the cost of an electricity generation plant, but the range of values shown in Figure 3 do not incorporate any such incentives. Based purely on these market forces, utilities looking at their bottom lines and public utility commissions looking for low-cost investment decisions will favor the construction of natural gas-fired technologies in the coming years.

Emissions

For each unit of energy produced, a megawatt-hour (MWh) of natural gas-fired generation contributes around half the amount of CO_2 emissions as coal-fired generation and about 68 percent of the amount of CO_2 emissions from oil-fired generation (Table 1).

While combustion of natural gas produces lower greenhouse gas emissions than combustion of coal or oil, natural gas does emit a significant amount of carbon dioxide (CO_2). In 2011, the power sector contributed about 33 percent of all U.S. CO_2 emissions.[64] Since 2005, total greenhouse gas emissions from the electricity sector have decreased, even as net electricity generation has remained steady, a result of natural gas-fired electricity

FIGURE 3: Estimated Levelized Cost of New Generation Resource, 2020 and 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013," April 15, 2013. Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm#cap_addition

Note: Price in 2011 cents per kilowatt-hour.

TABLE 1: Average Fossil Fuel Power Plant Emission Rates (pounds per Megawatt Hour)

GENERATION FUEL TYPE	CO_2 LB/MWH	SULFUR DIOXIDE LB/MWH	NITROGEN OXIDES LB/MWH
Coal	2,249	13	6
Natural Gas	1,135	0.1	1.7
Oil	1,672	12	4

Source: Environmental Protection Agency, "Clean Energy—Air Emissions," 2012. Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

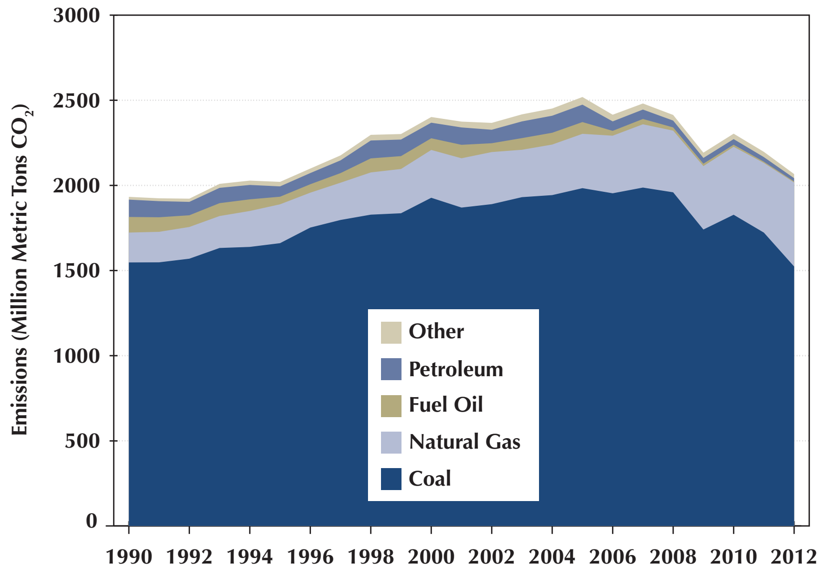
generation displacing petroleum- and coal-fired generation and an increase in the use of renewable generation. In 2012, CO_2 emissions from power generation were at their lowest level since 1993 (Figure 4).

Future Additions to Electricity Generation Capacity

There is strong evidence that the trends toward more natural gas in the power sector will continue in the near and medium term. With natural gas prices expected to stay relatively low and stable and the increasing likelihood of a carbon-constrained future, natural gas has become the fuel of choice for electricity generation by utilities in the United States.[65, 66] In 2012, the electric power industry planned to bring 25.5 gigawatts (GW) of new capacity on line, with 30 percent being natural gas-fired (and the remainder being 56 percent renewable energy and 14 percent coal.[67] Between 2012 and 2040, the U.S. electricity system will need 340 GW of new generating capacity (including combined heat and power additions), given rising demand for electricity and the planned retirement of some existing capacity.[68] Natural gas-fired plants will account for 63 percent of cumulative capacity additions between 2012 and 2040 in the Energy Information Administration (EIA) Annual Energy Outlook 2013 reference case, compared with 31 percent for renewables, 3 percent for coal, and 3 percent for nuclear (Figure 5).

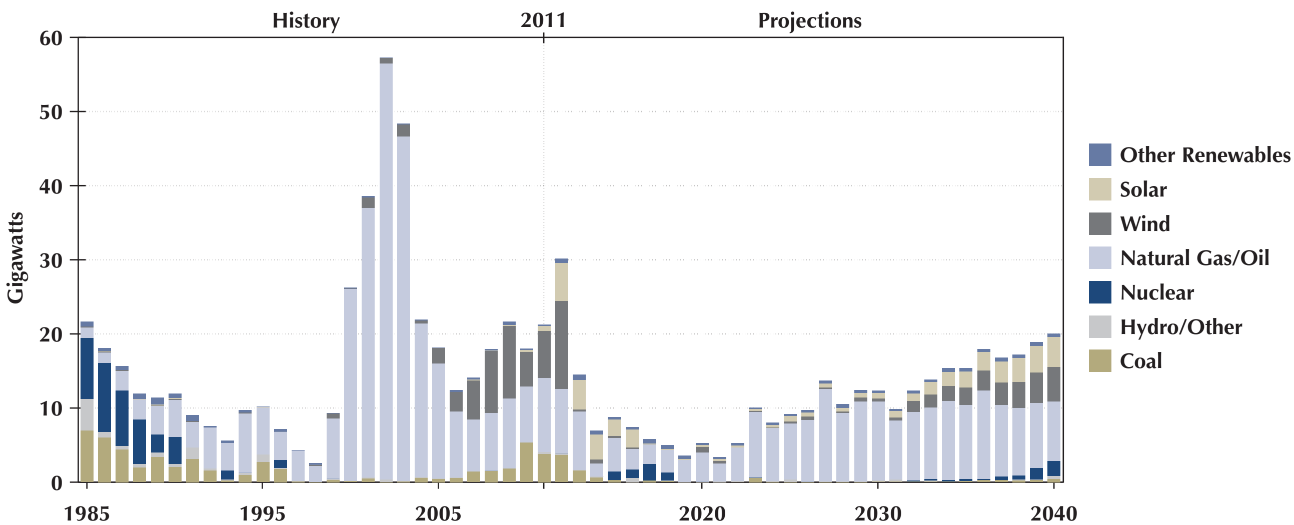
Federal tax incentives and state programs will contribute substantially to renewables' competitiveness in the near term.[69] For example, with the wind production tax credit, wind generation is expected to increase more than 18 GW from 2010 to 2015. Similarly

FIGURE 4: U.S. Emissions in the Power Sector, 1990 to 2012



Source: Energy Information Administration, "Monthly Energy Review," Table 12.6, March 27, 2013. Available at: http://www.eia.gov/forecasts/archive/aeo11/index.cfm

FIGURE 5: Additions to Electricity Generation Capacity, 1985 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013," April 15, 2013. Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm#cap_addition

with the solar investment tax credit, utility and end-use solar capacity additions are forecast to increase by 7.5 GW through 2016.[70] In addition to federal incentives, state energy programs mandate increased renewable energy capacity additions in thirty-eight states. These states have set standards specifying that electric utilities deliver a certain amount of electricity from renewable or alternative energy sources. Increasing the deployment of zero-carbon energy technologies such as renewables, nuclear, and carbon capture and storage needs to be a priority in order for the United States (and the rest of the world) to address climate change.

Fuel Mix Diversity

Since 1990 the share of generation from natural gas has increased from around 11 percent to 29 percent of the total net generation in 2012 (Figure 1), substantially increasing the diversity of the fuel mix. Natural gas-fired generation is expected to constitute just over 27 percent of the total generation mix in 2020, rising to 30 percent in 2035.[71] Fuel diversity is an important consideration for utilities looking to reduce their reliance on any particular energy source, as too much reliance on any one fuel can expose utilities or other power generation owners to the risks associated with price volatility. From a national perspective, fuel diversity is projected by EIA to remain about the same through 2040 with no single fuel being dominant.[72] Two things could change this outlook, however. One is a scaling back or reversal of the state and federal policies supporting zero-carbon generation, such as state renewable portfolio standards and federal tax incentives.[73] The other is a change in the outlook for the U.S. nuclear generation fleet. Competitive pressures from low natural gas prices have already caused one small, older (1974) plant—the 586 MW Kewaunee plant in Wisconsin—to announce its closure (even though its operating license does not expire until 2033).[74] Should more nuclear generation follow suit, these would likely be replaced by natural gas-fired generation. Given that 19 percent of U.S. electricity comes from nuclear power, there is concern that replacing these with natural gas and decreasing the emphasis on renewable energy deployment would push the U.S. power sector into a situation where fuel diversity is significantly reduced.

OPPORTUNITIES FOR FURTHER GREENHOUSE GAS REDUCTIONS

Beyond the increased use of lower-emitting fuels in the traditional, centralized power-generation system, certain fundamental changes in where and how electricity is generated have the potential to dramatically reduce greenhouse emissions from the sector. These opportunities and challenges are detailed below and are crucial if long-term emission reductions are to be made.

Distributed Generation

Generating electricity at or near the site where it is used is known as distributed generation. A common example is solar panels on the rooftops of homes and businesses, but natural gas is also used in conjunction with distributed generation technologies. For example, natural gas combined heat and power (CHP) systems in industrial, commercial, and residential settings are becoming a more commonplace type of distributed generation.

Traditionally, the power sector functions with centrally located power stations generating large quantities of electricity, which is transported to end users via electrical transmission and distribution lines. With distributed generation systems (also referred to as on-site generation or self-generation, and described in more detail in chapter 7), smaller quantities of electricity are generated at or near the location where it will be consumed, obviating the need for long electrical transmission lines. Additionally, natural gas CHP systems (discussed in more detail in chapter 6) are able to use waste heat from electricity production for practical purposes. Switching from a primarily centrally generated power generation system to a more efficient distributed system that captures waste heat avoids electrical transmission losses, requires less electricity to be generated, and uses less fossil fuel in aggregate, and therefore lowers greenhouse gas emissions.

Supply Side Efficiency

For a host of practical and economic reasons, centralized power generation will not be going away in the near or medium term. Basically, there are three categories of natural gas-fueled central power station: steam turbines, combustion turbines, and combined-cycle power plants (Appendix B). Each of these plant types has an average thermal efficiency. Thermal efficiency measures how well a technology converts the fuel energy input (heat) into electrical energy output (power). A higher thermal efficiency, other things being equal, indicates that less fuel is required to generate the same amount of electricity, resulting in fewer emissions. Steam turbines have the lowest efficiency at around 33 to 35 percent. Combustion turbines are around 35 to 40 percent efficient, and combined-cycle plants have thermal efficiencies in the range of 50 to 60 percent.

More efficient designs should be considered as new natural gas-fired capacity is added to the power sector. The Electric Power Research Institute (EPRI) asserts that it is technologically and economically feasible to improve the thermal efficiencies of steam turbine technology by 3 percent, increase combustion turbines to 45 percent efficient, and construct combined-cycle plants with 70 percent efficiency by 2030.[75] Higher thermal efficiencies translate into less fuel required to generate the same amount of electricity. EPRI's 2009 analysis estimates a potential CO_2 emissions reduction in 2030 of 3.7 percent from the power sector as a result of increasing the efficiency of new and existing fossil fuel-fired generation.[76]

Carbon Capture and Storage

In a carbon-constrained future, and with natural gas potentially playing a greater role in the future of the total generation mix natural gas plants with carbon capture and storage capability will need to be deployed to ensure greenhouse gas emissions are reduced over the long term. Carbon capture and storage projects have already been initiated, and several projects are planned in the next several years to demonstrate the feasibility of the technology, such as the Texas Clean Energy Project and the Kemper County integrated-gasification, combined-cycle (IGCC) project.[77] To date, these projects have been undertaken almost exclusively in conjunction with coal-fired power plants or industrial sources.[78] However, one international project in Norway, set to begin in 2012, endeavors to capture CO_2 from a natural gas CHP plant (similar to a combined-cycle plant) and sequester the CO_2 in an underground saline formation.[79]

In addition to sequestering CO_2 in saline formations, CO_2 is currently being injected into oil wells as part of tertiary, or enhanced, oil production (CO_2-EOR).[80] This storage option has the added benefit of providing an economic incentive, that is, compensation from the oil-field operator to the captured-CO_2 provider. In 2011, the National Enhanced Oil Recovery Initiative (NEORI) was formed to help realize CO_2-EOR's full potential as a national energy security, economic, and environmental strategy. In addition, NEORI suggests federal- and state-level action to support CO_2-EOR.[81]

Economics and Fuel Selection

For power plant operators, the economics of switching from coal to natural gas ultimately depend on underlying fuel prices, which in turn depend on individual location, operational and reliability requirements, and environmental regulations. In mid-2011, natural gas prices fell below coal prices on a dollar-per-energy-output basis. As the gap between the two fuels widened, the share of natural gas-fired power generation increased. However, by July 2012, natural gas prices had rebounded above $3.10 per thousand cubic feet, the cost point for coal at the time. Accordingly, coal-fired generation increased relative to natural gas-fired generation.[82] Future fuel substitution will depend on the variable prices of both coal and natural gas.

Competitive electric power markets, in some form, exist in 43 states. In competitive power markets, electricity is bid into the market based on production costs. Typically, fuel cost is the main driver of production cost, but fuel costs can vary depending on a plant's location. Other factors such as plant efficiency will also affect production cost, with newer more efficient plants able to bid into the market at lower prices than older plants. Renewable technologies such as hydro and wind have the lowest production costs (Figure 6), and can be bid into a market at near zero dollars. Next in the merit or price order is nuclear power, followed by lignite, a cheaper, softer coal with a high moisture content. Hard coal plants and natural gas combined-cycle plants are in the middle of the supply curve or bid stack. Finally, natural gas combustion turbine plants and oil and diesel plants are the most expensive plants to run and are basically only used during times of peak demand. Electricity system operators employ a least-cost dispatch methodology. The point at which the quantity of electricity demanded at any point in time crosses the price-ordered supply curve is known as the marginal generator, and this sets the market price. Coal- or natural gas-fired plants are the marginal generator in most competitive power markets. Even though other suppliers such as wind and nuclear have bid into the market at a price lower than the marginal generator, all units receive the marginal or market price for that time period.

Lower natural gas prices and greater quantities of low variable cost renewables are contributing to lower prices in competitive electricity markets. Current and forecast low natural gas prices were cited as one of the reasons behind the recently announced decision to shut down a 556 megawatt (MW) Wisconsin-based nuclear power station.[83] Additionally, there is evidence to suggest that lower natural gas prices suppress the development of renewables.[84] In this situation, government policies are undoubtedly necessary to ensure that zero-carbon generation sources are a growing, rather than declining, share of the U.S. energy mix.

Relationship Between Natural Gas and Renewables

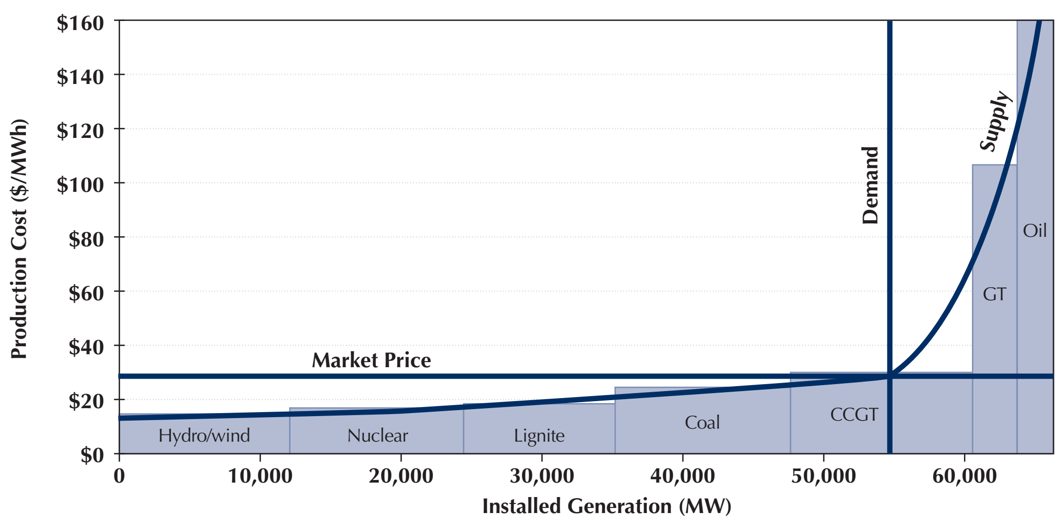
There is a complicated relationship between natural gas and renewables in the power sector, stemming from two aspects: 1) competition in the dispatch order between natural gas and renewables, and 2) the potential to produce renewable forms of natural gas.

For the most part, the relationship between natural gas and renewables is interpreted as competition in the power sector, by which renewables are seen as a threat to natural gas because they push natural gas-fired power plants off the bid stack. This phenomenon occurs because the power markets take bids on marginal costs rather than all-in costs. Because the marginal cost of wind is zero, it bids zero (or negative in some cases, reflecting the effect of production tax credits for wind power). Consequently, it is a price-taker in the markets, and it displaces the highest bidders, which are the price-setters. Historically, those price-setters are natural gas power plants, and so wind power displaces natural gas. Consequently, the relationship between gas and wind is one of rivalry. Natural gas interests audibly complain about this rivalry, with the criticism that policy supports for wind give it an unfair advantage in this competition. Renewable energy supporters counter that natural gas interests are not required to pay for their pollution (which is a form of indirect subsidy) and have enjoyed government largesse in one form or another for many decades.

Despite the perception that wind and natural gas are vicious competitors in a zero-sum game where the success of one must come at the demise of the other, the relationship is actually more nuanced. In fact, wind and gas benefit from each other because they both mitigate each other's worst problems. For wind, intermittency is a problem, and for natural gas, price volatility has been a problem historically. It turns out that the ability for natural gas power plants to serve as rapid response firming power is an effective hedge against wind's intermittency. And, it turns out the fixed fuel price (at zero) of wind farms is an effective hedge against natural price volatility. Thus, they are complementary partners in the power markets.

Almost all natural gas used today comes from geologic reserves formed many millions of years ago. Therefore, many people seeking a long-term sustainable energy option reject natural gas automatically because it is widely considered a fossil fuel that has a finite resource base. It is important to note that there are also renewable forms of natural gas, known as biogas or biomethane. This form of gas is mostly methane (CH_4) with a balance of CO_2, and is created from the anaerobic decomposition of organic matter. While renewable natural gas is a small fraction of the overall gas supply, it is not negligible. For example, landfill gas is already an important contributor to local fuel supplies at the local scale. And, recent studies have noted that the total potential supply available from wastewater treatment plants and anaerobic digestion of livestock waste is over 1 quadrillion British thermal units annually in the United States, which is more than 10 percent of the amount of renewable energy consumed in the United States in 2011.[85, 86, 87]

FIGURE 6: Generalized Representation of a Competitive Power Market



Source: Adapted from Rawls, Patricia, U.S. Department of Energy: National Energy Technology Laboratory, "The PJM Region: A GEMSET Characterization for DOE." December 13, 2002. Available at http://www.netl.doe.gov/energy-analyses/pubs/200220DecPJMregionHandout.pdf

KEY POLICY OPTIONS FOR THE POWER SECTOR

Significant policy decisions affecting the U.S. power sector today include regulations to address the interstate air pollution transport, the National Emissions Standards for Hazardous Air Pollutants, and the proposed New Source Performance Standards issued by the U.S. Environmental Protection Agency (EPA). For electricity generation plants to comply with the Cross State Air Pollution Rule and National Emissions Standards for Hazardous Air Pollutants, they will need to install pollution control technologies, a requirement that will affect coal-fired plants in particular.[88] PJM, the operator of the world's largest wholesale electricity market, located in the eastern United States, predicts that approximately 14 GW of coal-fired generation (out of an installed capacity of 78.6 GW of coal-fired generation) could be retired by 2015, largely due to these rules.[89] Questions have been raised about the implications of these retirements on the electricity system's capacity and ability to meet demand and specifically reserve margins. Reserve margins are the spare capacity that electricity system or market operators are required to maintain above the projected peak loads in order to ensure system reliability. While reserve margins appear sufficient in the short run, new, reliable baseload generation will be required in the next 10 to 20 years to fill the gap.

In late March 2012, EPA proposed CO_2 pollution standards for new electric power plants as part of its New Source Performance Standards program. The proposed standard is 1,000 pounds of CO_2 per megawatt-hour, and under this new standard all new power plants would need to match the CO_2 emissions performance currently achieved by highly efficient natural gas combined-cycle power plants. While new efficient natural gas, nuclear, or renewable energy plants would meet this standard easily, new coal-fired power plants could meet the standard only by capturing and permanently sequestering their greenhouse gas emissions using carbon capture and storage technologies. If adopted, this standard would favor new natural gas-fired generation over coal in the future.[90]

In the past few years, there has also been some interest in a federal-level renewable portfolio standard and, more recently, in a broader federal clean energy standard. Whereas a renewable portfolio standard typically credits only 100 percent-renewable generation such as wind, solar, geothermal, or new hydro power, a clean energy standard would create a mechanism to credit “cleaner” electricity generation as well, that is, generation that emits some CO_2 although less than a reference power plant technology such as a generic coal power plant. Under a clean energy standard proposal, credits would be available to new and incremental (upgrades and improvements to) natural gas-fired generation, natural gas with carbon capture and storage, and other relatively cleaner forms of electricity production.[91] Indiana and West Virginia have alternative energy portfolio standards, similar to a renewable portfolio standard; however, these standards allow natural gas-fueled generation to be a part of their clean energy goals. In this way, some policy-makers have recognized that there are significant emissions benefits to natural gas use.

There is a need, however, to continue moving the power generation sector to even cleaner generation (zero-emission sources), to reduce CO_2 emissions to levels that will stave off the worst effects of climate change.

A price on carbon is a highly effective policy that can provide an incentive for zero-emission sources but it is not the only option. Tax credits for renewable generation, carbon capture and storage, nuclear loan guarantees, and policies that promote energy efficiency are all being used, to some extent, in the United States to acccelerate the deployment of low-carbon energy.

CONCLUSION

Market forces are driving greater use of natural gas in the power sector, and the inherent qualities of natural gas combustion are leading to lower greenhouse gas emissions. Adoption of distributed generation technologies, more efficient technology, and carbon capture and storage with natural gas have the potential to lower greenhouse gas emissions further. Market forces are joined by policy decisions, enacted and pending, that impact coal-fired generation and will further discourage its use. In addition, some states' alternative energy portfolios count natural gas-fueled generation toward their medium-term clean energy goals.

Low natural gas prices are having an impact on the diversity of the fuel mix used in electricity generation. In the near term, the diversity of the fuel mix is increasing as fuel-switching from coal to natural gas proceeds; however, in the long term, a sustained low natural gas price may discourage investment in nuclear generation and renewables. Policy is necessary to ensure that the percentage of zero carbon-emission power generation is growing sufficiently to mitigate the most dangerous effects of climate change.

APPENDIX A: NATURAL GAS POLICY

1938	The Natural Gas Act of 1938 establishes federal authority over interstate pipelines, including the authority to set “just and reasonable” rates. It also establishes a process for companies seeking to build and operate interstate pipelines. Oversight of The Act is given to the Federal Power Commission.
1954–1978	Natural gas price controls eventually lead to scarcity and shortage.
1978	In response to supply shortages, Congress enacts the Power Plant and Industrial Fuel Use Act. The law prohibits the use of natural gas in new industrial boilers and new electric power plants. The goal is to preserve “scarce” supplies for residential customers.
1985	The Federal Power Commission is replaced by the Federal Energy Regulatory Commission, which issues Order 436, intended to provide for open access to interstate pipelines that would offer transportation service for gas owned by others.
1987	President Reagan signs into law the repeal of the remaining Fuel Use Act restrictions and incremental pricing, believing that the country’s natural gas resources should be free from regulatory burdens, which some saw as costly and counterproductive.
1990	On April 3rd, trading on natural gas futures begins at the New York Mercantile Exchange.
2005	The Energy Policy Act 2005 is passed, a bill exempting fluids used in the natural gas extraction process of hydraulic fracturing from protections under the Clean Air Act, Clean Water Act, Safe Drinking Water Act, and Comprehensive Environmental Response, Compensation, and Liability Act. The Act exempts companies drilling for natural gas from any requirement to disclose the chemicals involved in fracking operations, normally required under federal clean water laws. The proposed Fracturing Responsibility and Awareness of Chemicals Act would repeal these exemptions.
2011	Tough pollution limits (Cross State Air Pollution Rule) and limits on mercury, sulfur oxides (SO_x), and nitrogen oxides (NO_x) emissions (National Emissions Standards for Hazardous Air Pollutants) begin to drive older inefficient coal plants out of the market.
2011	A proposed Federal Clean Energy Standard credits natural gas relative to a coal reference power plant.
2012	New Source Performance Standard for CO_2 is proposed by EPA.

APPENDIX B: POWER PLANT TECHNOLOGIES

Steam Turbines

A common method of generating electricity is with steam turbines (Figure B-1). A power plant uses a combustible fuel—coal, oil, natural gas, wood waste—or nuclear fission to heat water in a boiler, which creates steam. The high-temperature, high-pressure steam is piped toward turbine blades, which move and rotate the attached turbine shaft, spinning a generator, where magnets within wire coils produce electricity.[92] Steam units have a relatively low efficiency. Only about 33 to 35 percent of the thermal energy used to generate the steam is converted into electrical energy, and the remaining heat is left to dissipate. Baseload electricity generation commonly relies on large coal- and nuclear-powered steam units on the order of 500 to 1000 MW or greater, as they can supply low-cost electricity nearly continuously.

Combustion Turbine

Combustion turbines are another widespread technology for centralized power generation (Figure B-2). In a combustion turbine, compressed air is ignited by burning fuel (e.g., diesel, natural gas, propane, kerosene, or biogas) in a combustion chamber. The resulting high-temperature, high-velocity gas flow is directed at turbine blades, which spin a turbine driving the air compressor and the electric power generator. Combustion turbine plants are typically operated to meet peak load demand, as they can be switched on relatively quickly. Another advantage is their ability to be a firm backup to intermittent wind and solar power on the grid, if needed. The typical size is 100 to 400 MW, and their thermal efficiency is slightly higher than steam turbines at around 35 to 40 percent.

Combined Cycle

A basic combined-cycle power plant combines a combustion turbine and a steam turbine in one facility (although there are other possible configurations) (Figure B-3). Combined-cycle plants waste considerably less heat than does either turbine alone. As combustion turbines became more advanced in the 1950s, they began to operate at ever-higher temperatures, which created increasing amounts of exhaust heat.[93] In a combined-cycle power plant, this waste heat is captured and used to boil water for a steam turbine generator, thereby creating additional generation capacity from the same amount of fuel. Combined-cycle plants have thermal efficiencies in the range of 50 to 60 percent. Historically,

FIGURE B-1: Steam Turbine

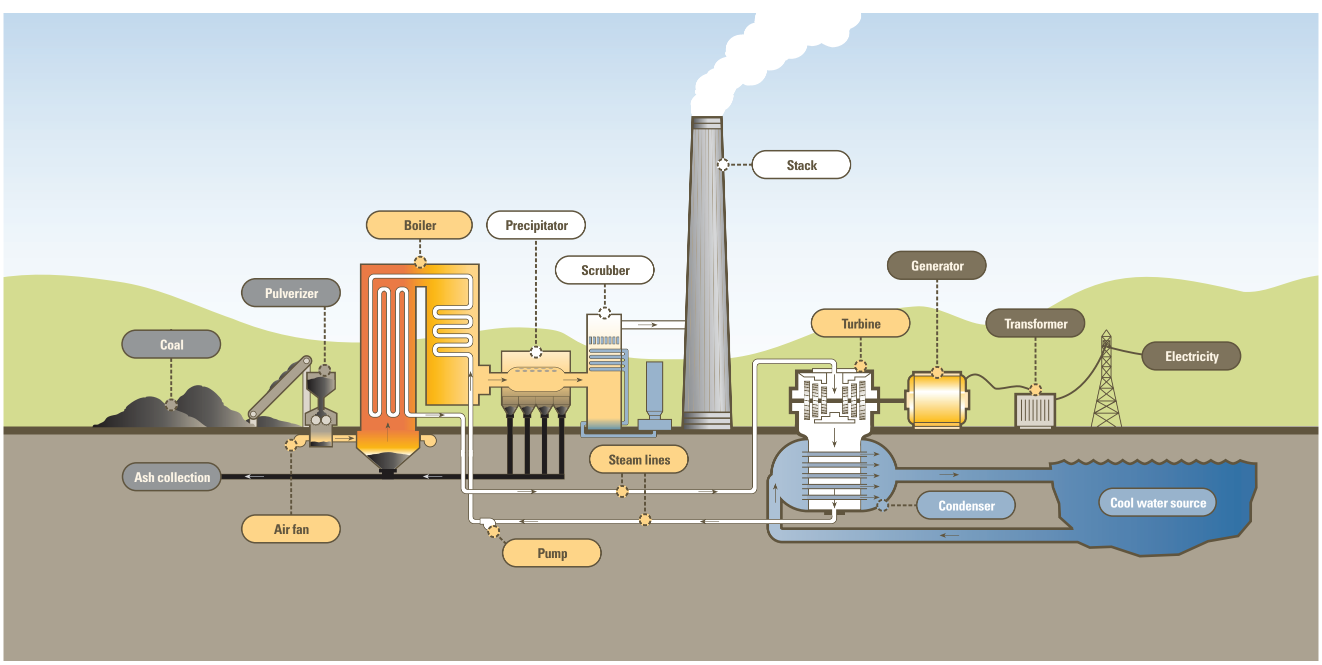


FIGURE B-2: Combustion Turbine

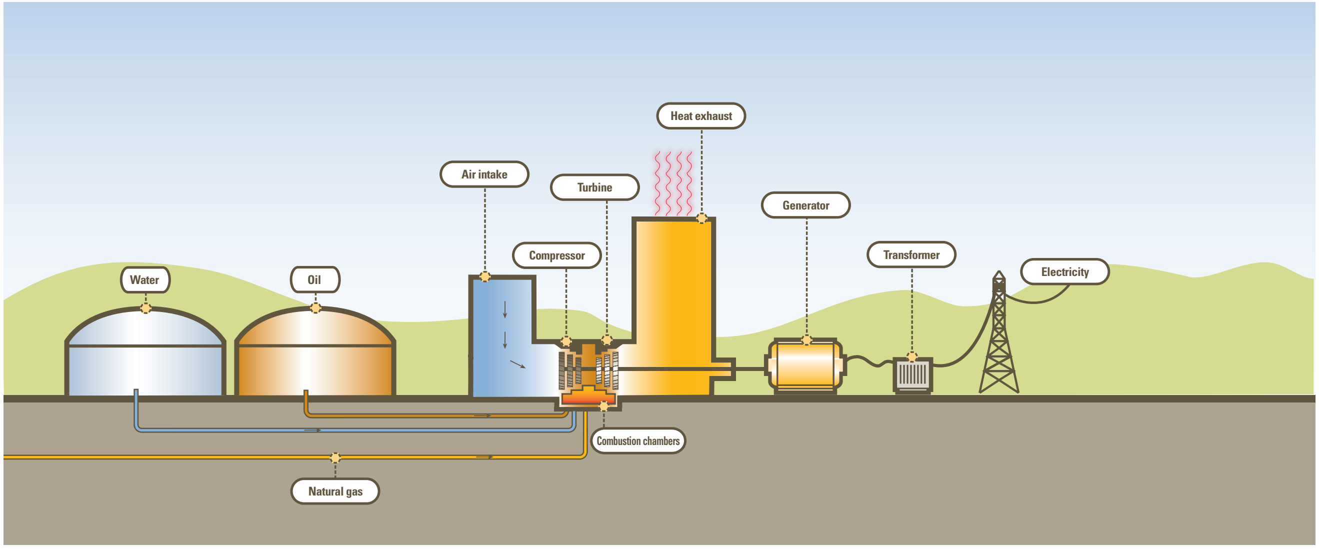
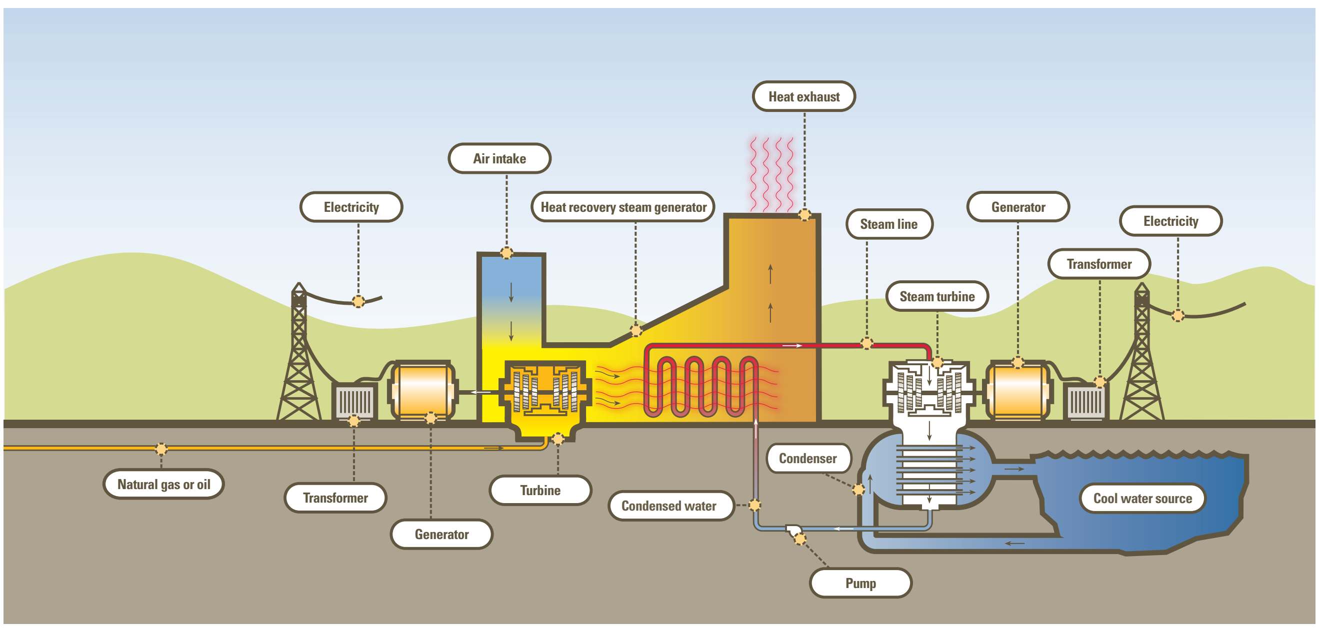


FIGURE B-3: Combined-Cycle Power Plant



they have been used as intermediate power plants, supporting higher daytime loads; however, newer plants are providing baseload support. Cutting edge natural gas combined-cycle power plants are coming online with thermal efficiencies at 61 percent with a correspondingly smaller emission of greenhouse gases; these plants are able to cycle on and off more frequently (than most of the installed power plant fleet) to more efficiently complement intermittent renewable generation.[94]

V. BUILDINGS SECTOR

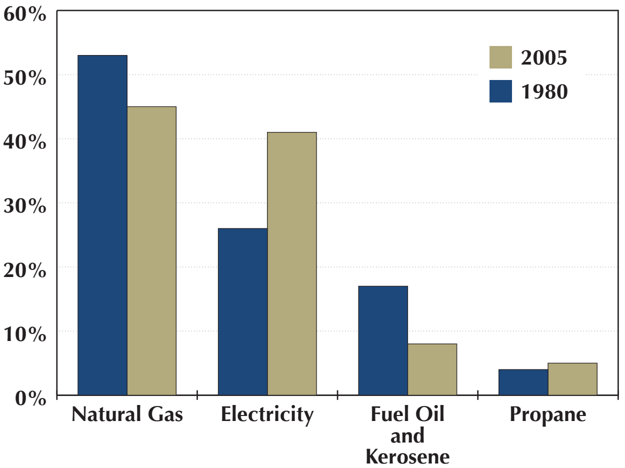
By Fred Beach, The University of Texas at Austin

INTRODUCTION

In 2009, the U.S. buildings sector accounted for about 41 percent of primary energy consumption.[95] Energy was delivered to more than 113 million residences and 4.8 million commercial and institutional buildings by four primary means: electricity, natural gas, district heat, and fuel oil. In both residential and commercial building sectors, natural gas and electricity have been the dominant fuel sources over the last 30 years. In the residential sector the proportion of electricity used has grown rapidly compared to other energy sources, largely driven by the proliferation of home electronics (Figure 1). In 2003 in the commercial sector, electricity and natural gas accounted for 87 percent of all energy used (Figure 2).[96] In 2011, residential and commercial buildings accounted for 34 percent of greenhouse gas emissions in the United States. Among fuels typically used in residential and commercial buildings, electricity usage accounted for 74 percent of carbon dioxide (CO_2) emissions from fossil fuel combustion, which accounts for the majority of greenhouse gas emissions from the buildings sector. Natural gas and other fuel combustion accounted for the remaining 26 percent.[97]

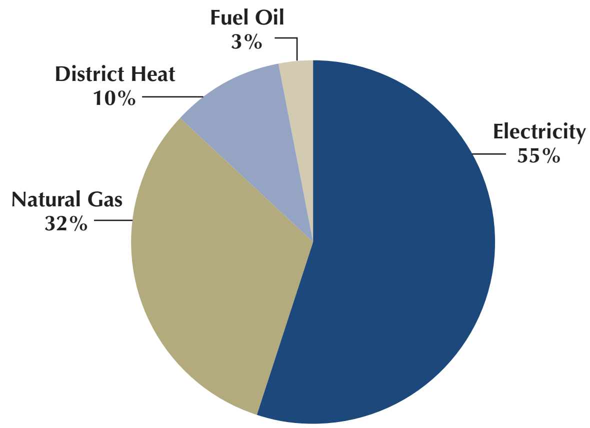
The fuel mix in the buildings sector heavily influences its greenhouse gas emissions. Natural gas consumed on site has relatively low emissions compared with the average emissions associated with liquefied petroleum gas (propane), fuel oil, or electricity. Electricity in particular typically has emissions far above those of natural gas. In 2011, more than 40 percent of U.S. electricity production came from coal-fired power plants, which create more CO_2 per unit of energy delivered than natural gas,

FIGURE 1: U.S. Residential Energy Consumption On-Site During 1980 and 2005, by Source



Source: Energy Information Administration, "Residential Energy Consumption Survey 2005, Table US3," 2005. Available at: http://www.eia.gov/consumption/residential/data/2005/c&e/summary/pdf/tableus3.pdf

FIGURE 2: U.S. Commercial Energy Consumption by Source, 2003



Source: Energy Information Administration, "Overview of Commercial Buildings, 2003," 2003. Available at: http://www.eia.gov/emeu/cbecs/cbecs2003/overview1.html propane, and fuel oil used on site.[98] Coal-fired electricity also produces sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury, which are associated with environmental damage and harmful health effects.

Because of the significant amounts of primary energy and greenhouse gas emissions associated with electricity generation and consumption, and the relatively higher greenhouse gas emissions footprint associated with fuel oil, switching from inefficient electricity or fuel oil to high-efficiency natural gas in buildings can yield significant emission reductions. This chapter provides an overview of energy consumption in residential and commercial buildings, which is driven by climate zone, business needs and activities, building size, and, in large part, consumer behavior. It explains why consideration of primary and "source-to-site" energy, a measure of energy consumption that occurs prior to consumer energy use on site, contributes to a more complete picture of energy consumed and emissions emitted. Accordingly, this chapter makes use of the concept of full-fuel-cycle efficiency, which is the appropriate energy and efficiency metric with which to compare consumer fuel choices and consequences for greenhouse gas emissions. It demonstrates how using natural gas appliances could lead to dramatic reductions in fuel consumption and greenhouse gas emissions. Finally, the chapter looks at how policy support, including efficiency programs, consumer information, and innovative funding models, can help to overcome the barriers to increased natural gas access and utilization in the buildings sector.

ENERGY USE IN RESIDENTIAL AND COMMERCIAL BUILDINGS

There are strong regional variations in the types of energy available to and used in buildings. A significant factor affecting energy use is where a building is located. Homes in colder climates tend to consume more energy, driven by heating (often called thermal) requirements. Nationally, 61 percent of residential energy is used for space heating and water heating (41 percent and 20 percent, respectively), while air conditioning (space cooling) consumes only 8 percent. Overall, thermal uses are dominant in all regions of the country (Figure 3). In the commercial sector as well, the dominant energy uses are thermal loads (space and water heating), followed by lighting (Figure 4).

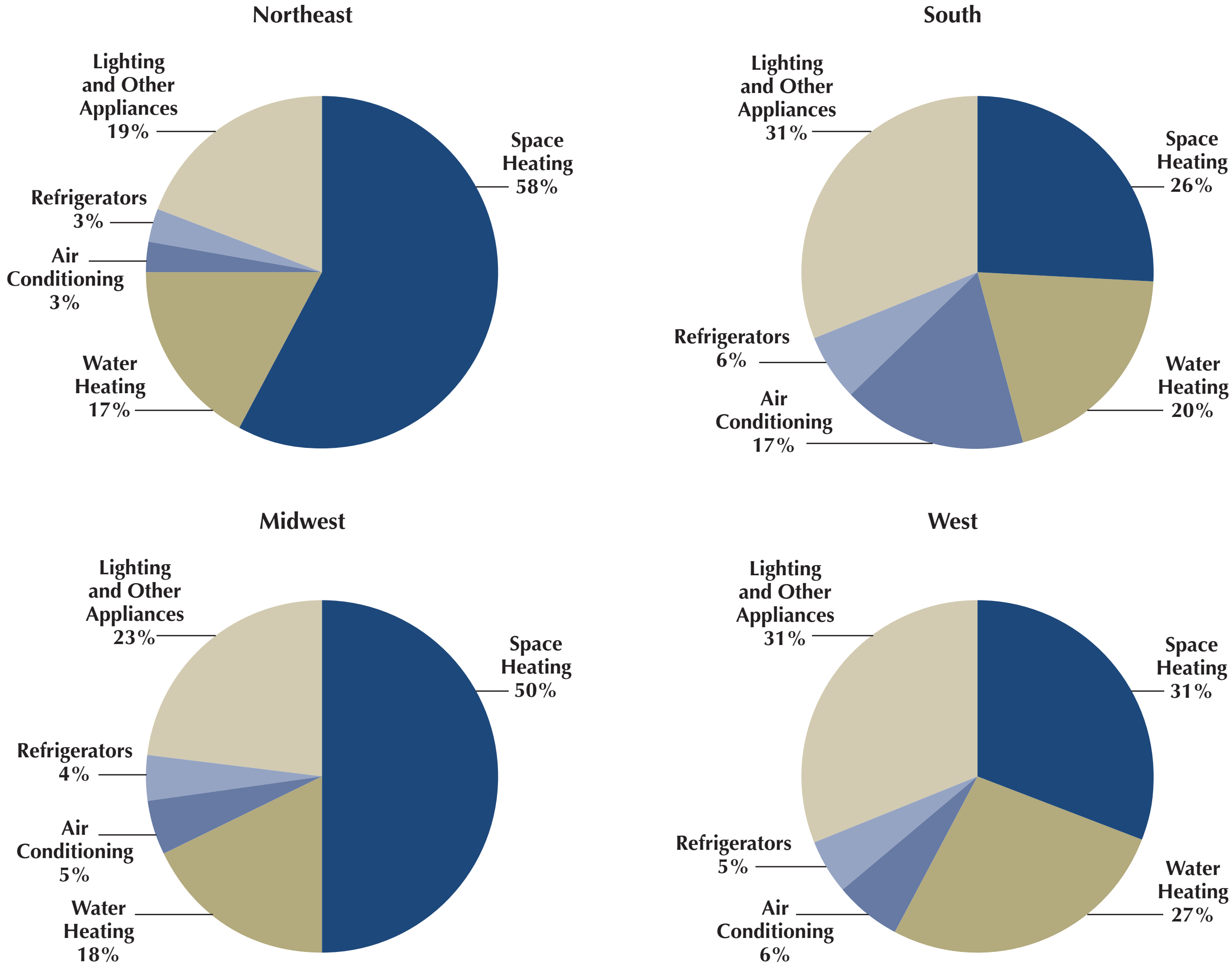
Energy Use in Commercial Buildings

Energy use among U.S. commercial buildings is quite diverse. Among commercial buildings, significant variation exists in the purpose and size of buildings, energy use, and emission profiles. Office space is the largest energy consumer, consuming 719 trillion Btu of electricity on site. Educational facilities are the second largest commercial consumer, using 371 trillion Btu of electricity on site. These two types of commercial buildings account for 36 percent of all the electricity used in buildings. Because they rely on relatively inefficient grid-delivered electricity rather than on-site generation (see below), they also have the highest emissions profiles.[99]

Commercial buildings vary in terms of energy intensity, measured in Btu consumption per square foot. The three most energy-intensive building sectors are food service, food sales, and health care, which use 258, 200 and 188 Btu per square foot per year, respectively.[100] While 84 percent of food service square footage is served by natural gas, only 60 percent of food sales square footage uses this fuel. The food service sector requires a large amount of thermal energy for cooking and cleaning, while energy use for food sales is predominantly for refrigeration. Thermal demands for in-patient healthcare are also heavy, with large amounts of food preparation, water heating, and cleaning. With these demands, 95 percent of building stock used for in-patient health care is served by natural gas, while only 59 percent of outpatient health care facilities use natural gas where are there are lower thermal loads.[101]

Building size also plays an important role in energy consumption and fuel source. Commercial buildings of more than 100,000 square feet account for only 2 percent of the total number of buildings, but they account for more than 34 percent of total floor space and more than 40 percent of total energy use (Figure 5). Clearly, this segment exhibits a higher concentration of high energy consumption, while being less fragmented in ownership than smaller buildings. Among large buildings of over 100,000 square feet, 77 percent use natural gas for space heating.[102, 103] The predominance of natural gas for heating in the largest of buildings, food service, and in-patient hospitals can be directly attributed to the greater overall efficiency and lower cost of natural gas over electricity for thermal applications such as space heating, water heating, and cooking.

FIGURE 3: **U.S. Home Energy Consumption By End Use, 2005**



Source: Energy Information Administration, "Annual Energy Review 2009," Table US12. Available at http://www.eia.gov/consumption/residential/data/2009/#consumption-expenditures

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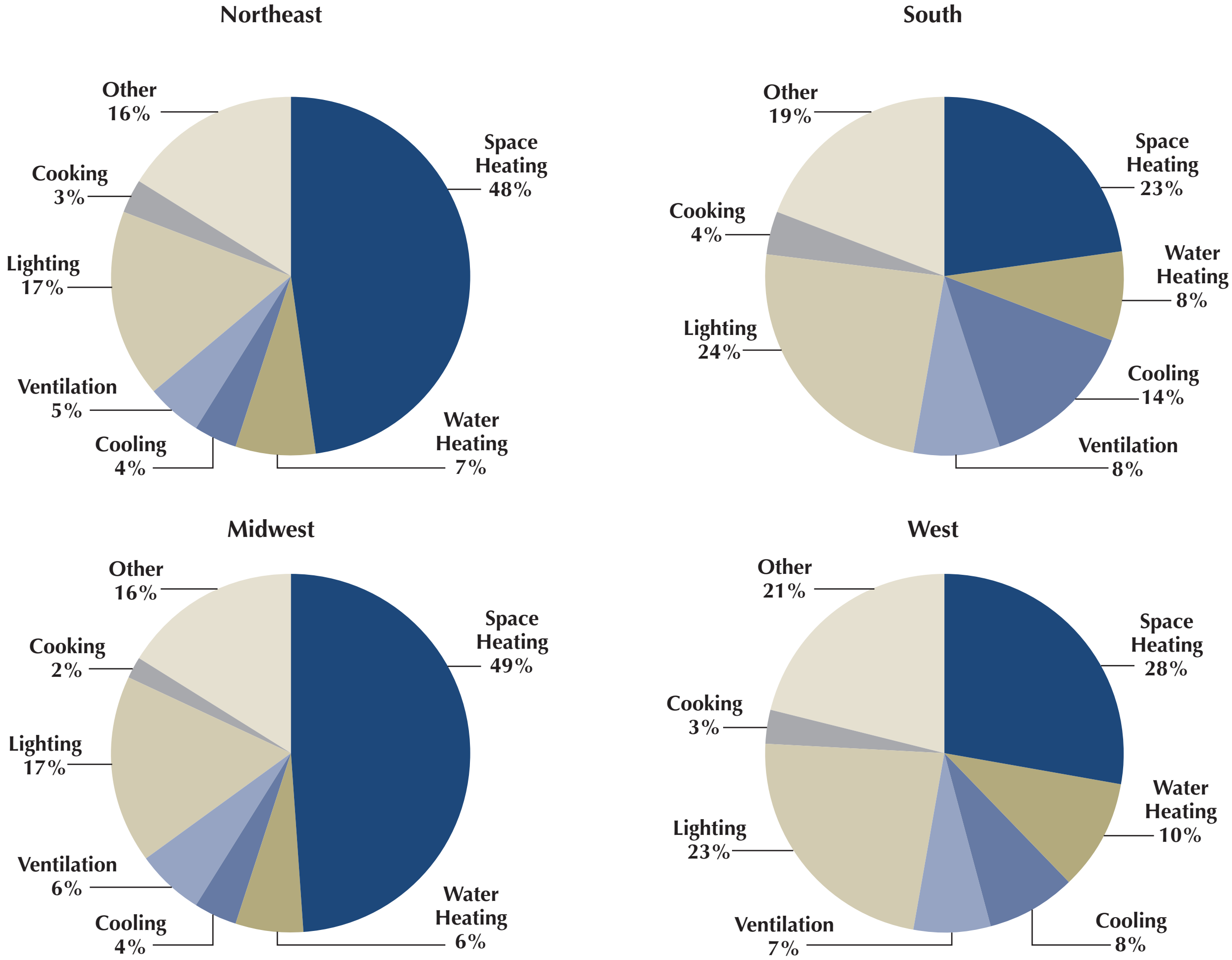
The types of activities carried out in commercial buildings also influence the type of energy used. Office buildings tend to utilize electricity rather than natural gas because many of their primary loads, such as lighting, elevators, personal computers, servers, scanners, and printers, cannot be served by natural gas. Lodging, health care, and food service, in contrast, can more easily use natural gas for cooking, hot water, cleaning, and laundry, and, consequently, they use proportionally more natural gas than office buildings.

Local climate plays a large role in determining what type of energy is used, and how. The majority of commercial (and residential) buildings are located in colder climate zones (zones 1 to 4), which encompass much of the country except for the Deep South and the Southwest. In colder zones, winters are cold enough for frequent, substantial space heating, and the average amount of energy needed to heat a building during the winter, measured in heating degree days, is two to four times the average amount of energy needed to cool a building during the summer (measured in cooling degree days) (Figure 6). Still, space and water heating account for the greatest energy use in buildings regardless of climate zone (Figures 3 and 4).

FIGURE 4: U.S. Commercial Energy Consumption by End Use, 2003



Source: Energy Information Administration, Commercial Buildings Energy Consumption Survey 2009, "Building Characteristics," Table E1a. Available at: http://www.eia.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/detailed_tables_2003.html#consumexpen03

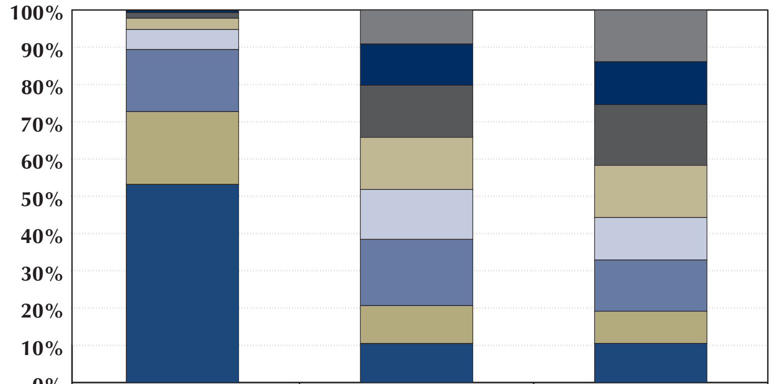
Energy Use in Residential Buildings

The prevalence of natural gas access and use in homes varies across U.S. climate zones, even though natural gas is a more efficient fuel choice for thermal loads. Natural gas appliances tend to be underrepresented in use, even when there is access to the fuel. In the two coldest regions in the country, natural gas is the preferred fuel for heating water in 23.7 million homes, while electricity is used in 10.8 million homes. The numbers suggest that nearly all of the homes using gas for space heating are also using it for water heating.[104] Nationwide, the story is different. Forty percent of households with natural gas access used electric appliances for space heating, water heating, or both in 2009, and that number has increased in recent years, with a four-million-household increase in residences with natural gas access using electric space heating.[105]

In warmer climates, natural gas use is less common than electricity for space heating—12.3 million residences use natural gas compared with 16.5 million using electricity.[106] However, natural gas and electricity are equally popular for water heating with an even split at 16 million homes each.[107] In these areas, more than 3 million homes had access to natural gas (as indicated by water heating usage) but did not use it for space heating.

Appliances, such as clothes dryers, ovens, and cooktops, are available in either electric, natural gas, propane, or fuel oil models, with electric and natural

FIGURE 5: Number of Non-Mall Commercial Buildings, Floor Space and Consumption by Size, 2003



	Total Buildings (thousand)	Total Floorspace (million square feet)	Total Consumption (trillion BTU)
Over 500,000 square feet	8	5,908	906
200,001 to 500,000 square feet	26	7,176	751
100,001 to 200,000 square feet	74	9,064	1,064
50,001 to 100,000 square feet	147	9,057	913
25,001 to 50,000 square feet	261	8,668	742
10,001 to 25,000 square feet	810	11,535	899
5,001 to 10,000 square feet	948	6,585	563
1,001 to 5,000 square feet	2,586	6,789	685

Source: Energy Information Administration, "Natural Gas Consumption and Conditional Energy Intensity by Building Size for All Buildings, 2003" Table C31. Available at: http://www.eia.gov/consumption/commercial/data/archive/cbecs/cbecs2003/detailed_tables_2003/2003set16/2003html/c31a.html

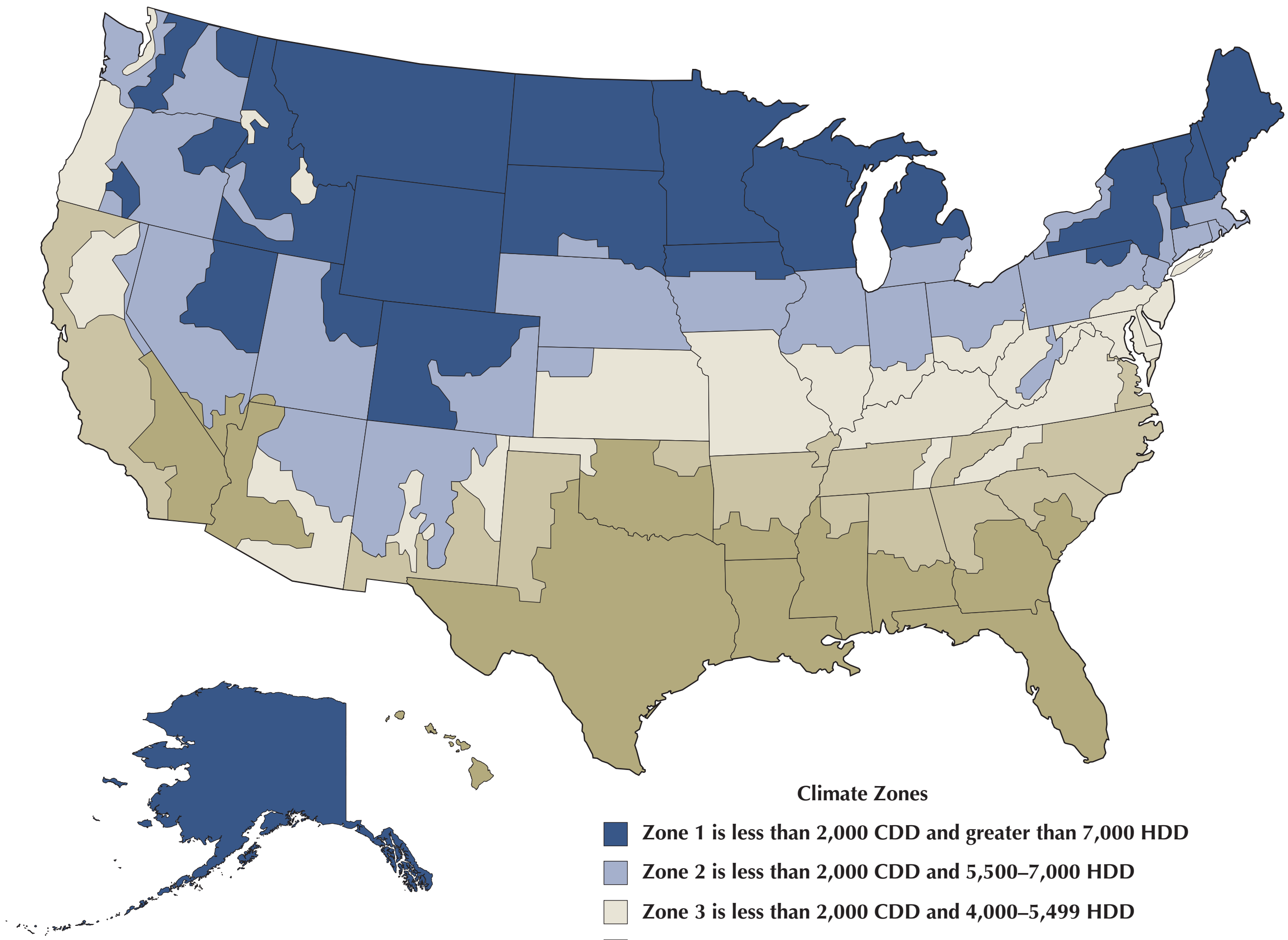
gas models being the most common by far (Figure 7). Nationwide, electric dryers outnumber gas models 4 to 1 (71.8 million compared to 17.5 million). For cooking appliances, whether ovens or cooktops, the ratio is almost 2 to 1 (68.1 million homes use electricity and 38.4 million use natural gas).[108] In theory, the use of these appliances should be independent of climate zone variations since they operate within the heated and cooled space of homes. Yet, natural gas appliances are significantly underrepresented in all climate zones.[109]

In the two coldest regions, zones 1 and 2, natural gas is the dominant space heating fuel, heating 24.8 million homes in 2005. In contrast, only 5.6 million homes used electric space heating in the same year (Figure 4).[110] Nationally, natural gas is also the chief fuel source for heating in commercial buildings. In 2003 in colder climate zones, it provided heat for 69 to 75 percent of all commercial floor space, but only 47 percent in zone 5, the warmest region.[111]

SOURCE-TO-SITE EFFICIENCY, SITE EFFICIENCY, AND FULL-FUEL-CYCLE EFFICIENCY

Building energy consumption can be measured in terms of fuel use on site: kilowatts of electricity, cubic feet of gas, and gallons of propane or fuel oil. This site energy is the total of all energy consumed at a building as measured by the electric and natural gas meters as it enters the building and/or by fuel oil or propane delivery. However, site energy does not tell the full energy story, because energy, whatever the source, must be extracted and delivered to the point of use, incurring losses along the way that are not reflected in the readings on customers' meters or delivery bills. As discussed in chapter 4, fossil fuels, such as coal or natural gas, are most often used to generate electricity. The term "source-to-site" generally refers to the total energy consumed in the course of extracting, processing, and delivering a unit of energy to a building, and in the case of electricity, energy associated with generation, transmission, and distribution. In other

FIGURE 6: **U.S. Climate Zones, Heating Degree Days vs. Cooling Degree Days**



Source: Energy Information Administration, "U.S. Climate Zones," 2004. Available at http://www.eia.gov/emeu/recs/climate_zone.html

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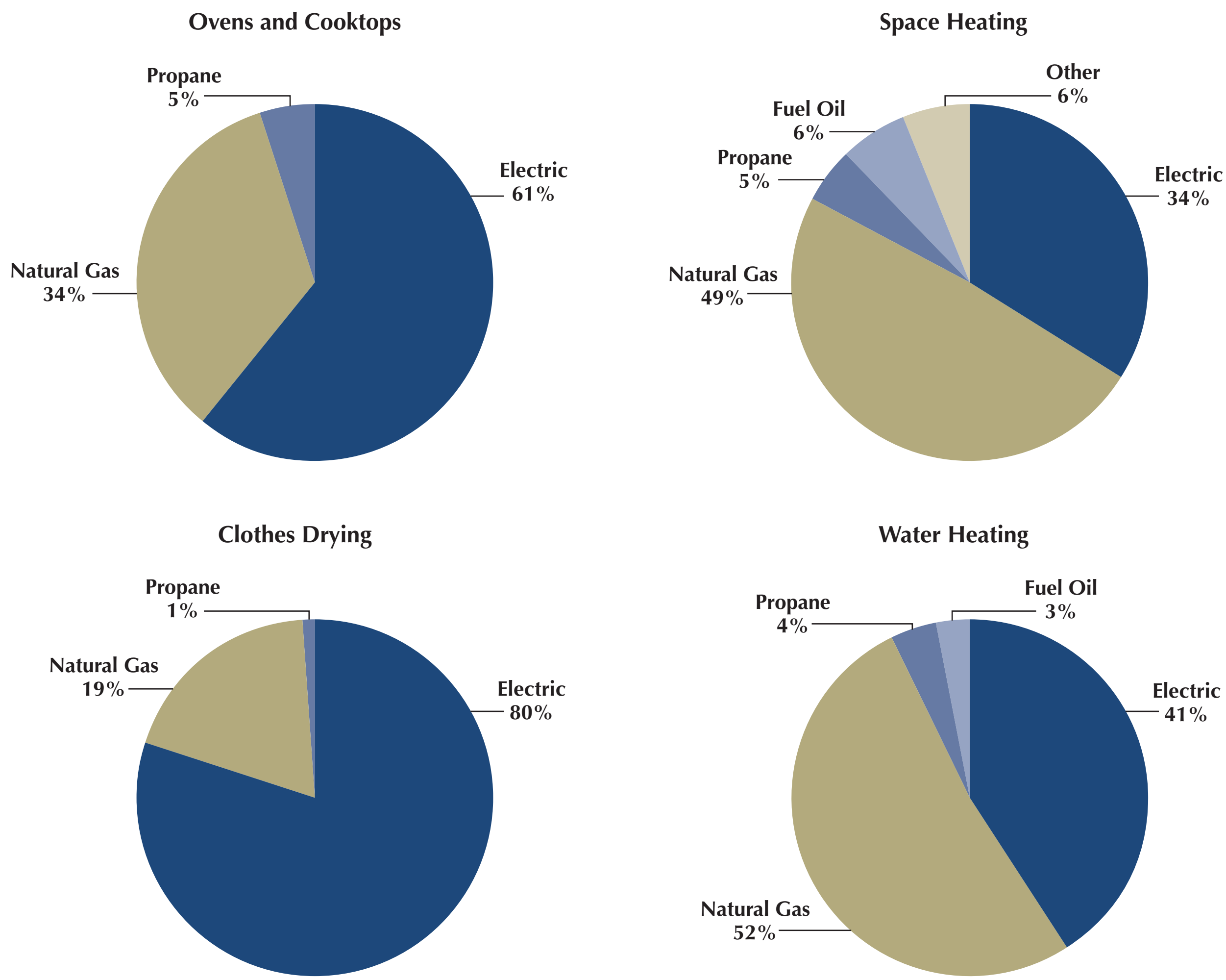
words, source-to-site efficiency is the energy required—accounting for losses—to bring usable energy to the consumer. Source-to-site efficiency varies widely by fuel. Often, direct fuel consumption has much higher source-to-site efficiencies compared with electricity, where energy is lost in the conversion and transmission of primary fuels to electrical energy. To assess the efficiency of total energy use, the source-to-site efficiency must be multiplied by the efficiency of the end-use appliances and equipment—the site efficiency. Combining source-to-site efficiency and site efficiency leads to the third—important and often overlooked—measure of efficiency, full-fuel-cycle efficiency.

Source-to-Site Efficiency

Electricity generation has the lowest source-to-site efficiency of all energy types. Centralized electricity generation and distribution through power lines is on average 32 percent efficient in the United States. The process of generating electricity incurs substantial losses, such that for every unit of electricity registered at a building's meter, three times the amount of primary energy was required to generate and distribute it. The majority of energy losses occur at the power plant, especially at cooling towers that emit waste heat into the atmosphere in the form of steam. The Western Electricity

FIGURE 7: Appliance Fuel Sources by Number of Units in U.S. Homes, 2009



Source: Energy Information Administration, "Residential Energy Consumption Survey 2009," Table HC3.1, Available at: http://www.eia.gov/consumption/residential/data/2009/

Coordinating Council, which covers the western United States, has the highest efficiency, at 38 percent, primarily due to its high percentage of hydropower, which has a higher conversion efficiency than coal- or natural gas-fired generation. The Midwest Reliability Council region in the Upper Midwest has the lowest efficiency, at 28 percent, due to a large percentage of coal plants using older, less efficient technology.[112] Transmission and distribution over power lines results in additional losses and reduces the source-to-site efficiency even further, by roughly an additional 7 percent, with longer lines experiencing greater losses. In total, up to two-thirds of the fuel that is burned for electricity production is wasted. In addition to providing no useful work in the economy, it releases significant greenhouse gas emissions in the process.

The production and distribution of natural gas, fuel oil, and propane also have inefficiencies. These fuels must be extracted from the ground, processed or refined to remove impurities and other liquids and gases, and finally transported to the building. During each of these steps, energy is used and a small amount of energy is lost but, in total, these losses are considerably less than the losses associated with electricity production and distribution. The source-to-site efficiency of natural gas is approximately 92 percent, around three times higher than the source-to-site efficiency of centrally generated electricity.[113] Other fuels commonly consumed onsite in residential buildings, fuel oil and propane, are also much more efficient than electricity. The average source-to-site efficiency of fuel oil is about 88 percent, and of propane, about 89 percent.[114]

Considering the source-to-site efficiency of different fuels offers a more accurate comparison of the fuel used in buildings. For example, in 2008, the total site consumption by residential and commercial buildings was 9.37 quadrillion Btu for electricity and 8.28 quadrillion Btu for natural gas. However, the amounts of primary energy consumed differed dramatically between electricity and natural gas, because of their different source-to-site efficiencies (compare Figures 8 and 9). About three times as much primary energy is used to generate and transmit electricity than is ultimately consumed onsite in buildings.

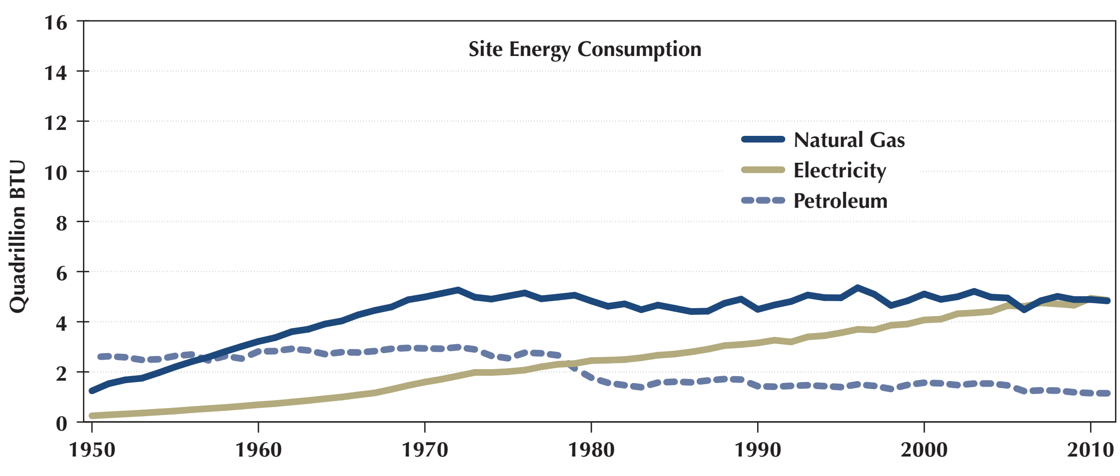
The relative efficiencies of on-site fuel use and grid-supplied electricity have major consequences for the greenhouse gas emissions associated with the U.S. building stock. Only accounting for site energy consumption misses energy losses and resulting greenhouse gas emissions associated with energy production and delivery. These losses account for a significant portion of total greenhouse gas emissions from the residential and commercial sector and should be accounted for when comparing fuel options. The use of grid-supplied electricity is growing, while direct natural gas consumption by residential and commercial buildings remains relatively flat. Increasing the amount of natural gas instead of electricity used in buildings would require fewer resources to provide the same amount of on-site energy and would lower the greenhouse gas emissions per unit of useful energy consumed.

Site Efficiency and Full-Fuel-Cycle Efficiency

Once energy is delivered to a building, it is used in an appliance or piece of equipment that has its own distinct efficiency level. Taken together, the source-to-site efficiency of the fuel delivered and the site efficiency of its use give a more complete picture of the total efficiency of consumer fuel and appliance choice and the resulting emissions. Source-to-site efficiency considered along with site efficiency yields an appliance's full-fuel-cycle efficiency.

To find the full-fuel-cycle efficiency of an appliance or piece of equipment, the efficiency of the source-to-site energy is multiplied by the efficiency of the appliance and associated equipment. For example, energy efficiency standards established in 2012 by the Department of Energy (DOE) for water heaters with storage tanks are 93 percent for electric-resistance units and 62 percent for natural gas models.[115] However, when these models' respective source-to-site efficiency is factored in, their full-fuel-cycle efficiencies are 30 percent for the electric model and 75 percent for the natural gas model. Therefore, despite the higher site efficiency rating of the electric-resistance water heater, it requires the use of significantly more primary energy

FIGURE 8: Residential Site Energy Consumption, 1950 to 2010



Source: Energy Information Administration, "Today in Energy," March 6, 2013. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=10251 and leads to the emission of more greenhouse gases than does the natural gas appliance for the same level of output in the building. Consequently, electric-resistance water heaters consume roughly twice the primary energy of the natural gas models.

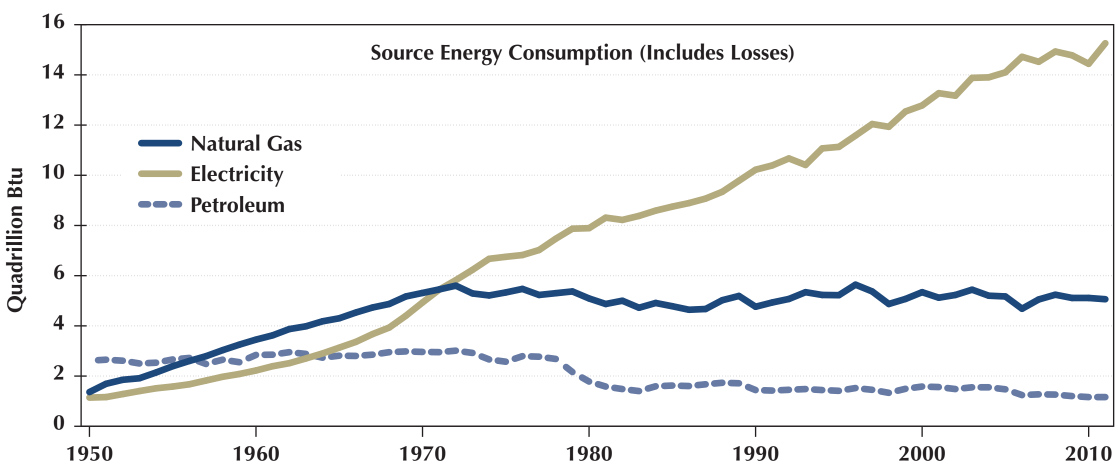
Source efficiencies and site efficiencies can vary even further. Minimum efficiency standards for appliances promulgated by DOE are continuing to push the site efficiency ratings of new appliances higher. While this discussion compares widely used electric and natural gas water heaters, newer technologies such as electric heat-pump water heaters are also available that are two to three times more efficient than the conventional electric-resistance models analyzed here,[116] and solar water heating technologies offer high full-fuel-cycle efficiencies and can be a cost-effective option.[117] Furthermore, the source efficiencies and associated greenhouse gas emissions vary, because of the regional differences in source efficiency of power generation. It is clear that, despite geographic variation, a natural gas water heater yields significant energy savings compared with an electric-resistance water heater in every North American Electric Reliability Corporation Region in the country (Figure 10).[118]

EMISSIONS COMPARISON: NATURAL GAS VERSUS OTHER DIRECT FUELS

In addition to the energy savings delivered by the higher full-fuel-cycle efficiency of appliances using natural gas, there is also a large difference in greenhouse gas emissions. Residential energy use has been a growing contributor to CO_2 emissions for the last two decades, and the trend is expected to continue (Figure 11).[119] The negative consequences in terms of emissions of this upward trend in electricity use are exacerbated by the low average efficiency of grid electricity and the high average carbon fuel intensity of the U.S. electricity generation portfolio. Furthermore, given the high level of coal use in U.S. electricity production, increased electricity use leads to significant increases in sulfur dioxide, nitrogen oxides, and mercury emissions, where pollution controls are not in place.

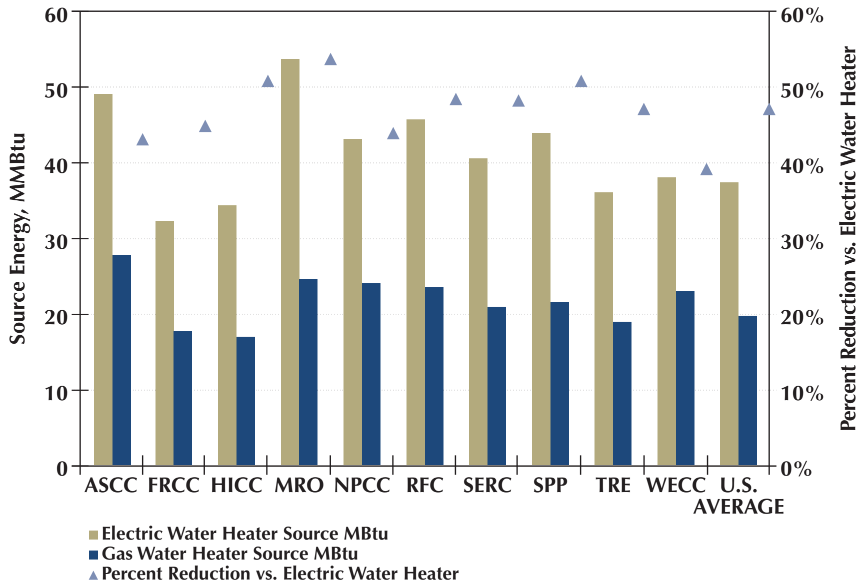
Greenhouse gas emissions can be reduced by switching from lower-efficiency fuels and appliances such as an electric-resistance water heater to higher efficiency fuels and appliances such as a natural gas water heater. However, the reductions will vary by region. The relative percentage reductions of greenhouse gas emissions by switching appliances or fuels is a combination of the full-fuel-cycle efficiency of the appliances and the CO_2-emission intensity of the electricity generation portfolio in a given region. The varied carbon intensities of electric generation in each North American Reliability Council (NERC) region offer different relative benefits from switching an electric-resistance water heater to a natural gas model (Figure 12). The relative benefits are most clearly demonstrated in the following examples. In the NERC region overseen by the Northeast Power Coordinating Council in the northeast United States and Eastern Canada, where a large percentage of the electricity comes from

FIGURE 9: Residential Primary Energy Consumption, 1950 to 2010



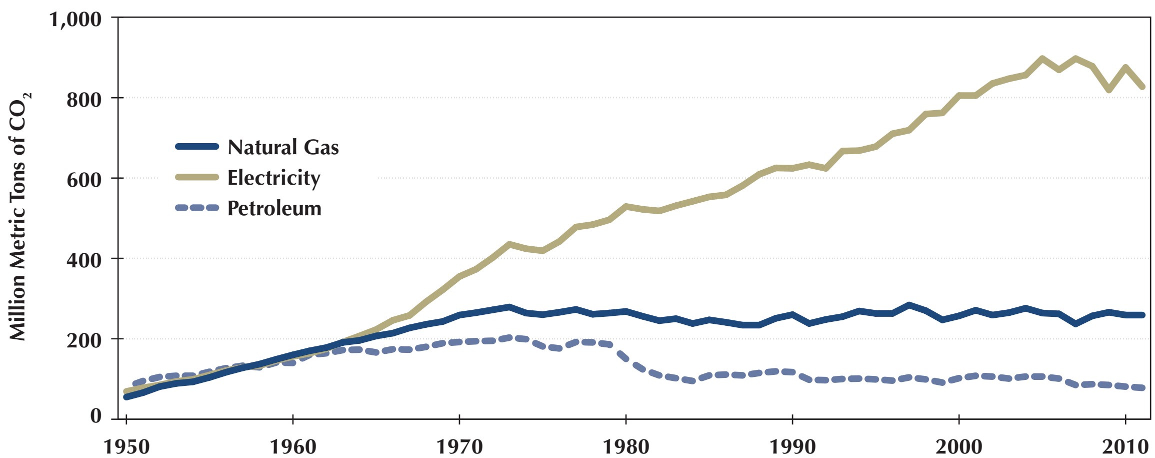
Source: Energy Information Administration, "Today in Energy," March 6, 2013. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=10251

FIGURE 10: **Consumption of Source Energy by Water Heaters by North American Electric Reliability Corporation Region, 2005**



Source: Gas Technology Institute, "Source Energy and Emission Factors for Building Energy Consumption" 2009, Tech. rep., Natural Gas Codes and Standards Research Consortium, American Gas Foundation. Available at: http://www.aga.org/SiteCollectionDocuments/KnowledgeCenter/OpsEng/CodesStandards/0008ENERGYEMISSIONFACTORSRESCONSUMPTION.pdf

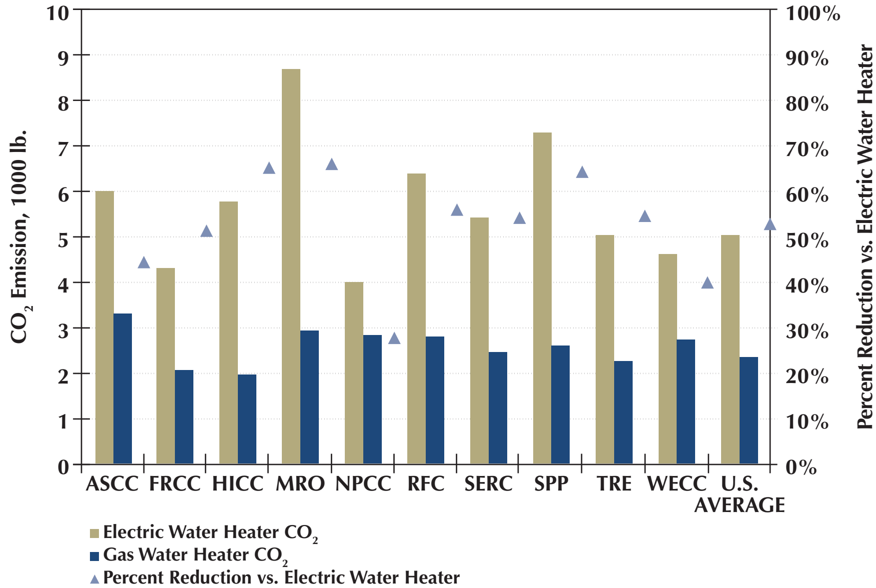
FIGURE 11: **Residential CO_2 Emissions from Energy Consumption, 1950 to 2010**



Source: Energy Information Administration, "Today in Energy," March 6, 2013. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=10251

less carbon-intensive hydroelectric and nuclear power, switching from an electric to natural gas water heater results in CO_2 reductions of 30 percent. By contrast, the same switch results in emissions reductions of 70 percent in the Midwest Reliability Organization region in the Midwest where substantial amounts of older coal-fired power generation contributes to a significantly more carbon-intensive electric generation mix.

FIGURE 12: CO_2 Emissions from Water Heaters by North American Electric Reliability Corporation Region, 2005

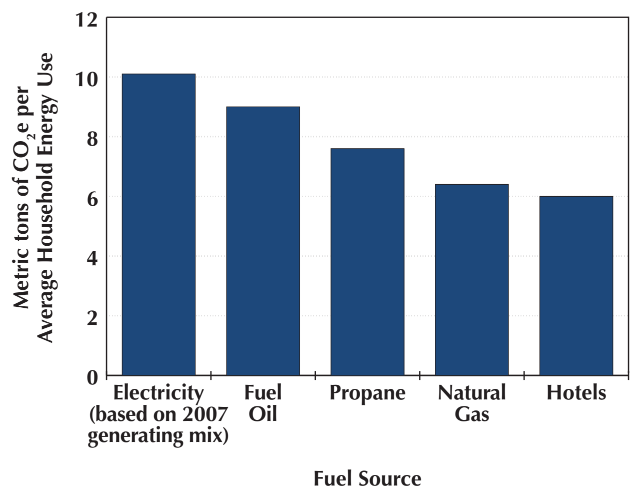


Source: Gas Technology Institute, "Source Energy and Emission Factors for Building Energy Consumption" 2009, Tech. rep., Natural Gas Codes and Standards Research Consortium, American Gas Foundation. Available at: http://www.aga.org/SiteCollectionDocuments/KnowledgeCenter/OpsEng/CodesStandards/0008ENERGYEMISSIONFACTORSRESCONSUMPTION.pdf

An average U.S. home using natural gas for space heating, water heating, cooking, and clothes drying is responsible for substantially fewer greenhouse gas emissions than homes using other fuel sources (Figure 13). In this example, natural gas use produces an average of 44 percent fewer emissions than electricity use.[120] Such a difference in energy use and CO_2 emissions is true for all energy uses in buildings where natural gas is an alternative to grid electricity as well as the direct use of propane and fuel oil. The two main factors determining the efficiency and emissions benefits from appliance to appliance are the full-fuel-cycle efficiency of the appliance and the emission-intensity of the primary fuel.

Emissions associated with natural gas use compared with electricity are lower for CO_2 and some pollutants. Considering the lower emissions of natural gas and its higher full-fuel-cycle efficiency, residential natural gas use results in 40 to 65 percent lower emissions of CO_2, 90 to 98 percent lower emissions of SO_2, and 50 to 88 percent lower emissions of NO_X. Residential natural gas use is free of any mercury emissions.[121]

FIGURE 13: Full-Fuel-Cycle Greenhouse Gas Emissions for Average New Homes



Source: Source: American Gas Association, "A Comparison of Energy Use, Operating Costs, and CO_2 Emissions of Home Appliances," October 20, 2009. Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/demand/Pages/Comparison-Energy-Use-Operating-Costs-Carbon-Dioxide-Emissions-Home-Appliances.aspx

Note: Assumes fuel used for space heating, water heating, cooking, and clothes drying. All appliances are assumed to meet federal minimum efficiency standards. The fuel oil home assumes electricity is used for cooking and clothes drying. The new home assumes a one-story single-family detached home with 2,072 square feet of conditioned space and 4,811 heating degree days.

Reducing Emissions Through Fuel Substitution and On-Site Energy Production

Natural gas can provide a means to increase a building's total full-fuel-cycle efficiency and decrease its emissions profile in many cases. This improvement is most readily achieved in thermal applications, such as natural gas space heating and water heating. While buildings with older natural gas- or oil-fired boilers and furnaces can improve their efficiency and lower their emissions by upgrading to newer models, greater emission reductions may be achieved by removing electric appliances and replacing them with models using natural gas. While natural gas appliances have a comparable or slightly lower site efficiency than electric-resistance appliances, natural gas is often, on a full-fuel-cycle basis, two to three times more efficient than electricity.[122]

Significantly greater benefits can be realized when grid power is replaced by power produced on site. Combined heat and power (CHP) systems provide a means for buildings with high electrical demand to increase their efficiency and reduce emissions. A CHP system uses a fuel such as natural gas to generate electricity on site, capturing waste heat to meet on-site thermal loads (Table 1). (For a more extensive treatment of CHP see chapter 6.) Fuel cells and micro-turbine technologies provide another means for buildings to generate their own electrical power on site using natural gas. The waste heat generated by these devices can then be used for space heating, water heating, and other thermal loads to raise the overall full-fuel-cycle efficiency of these devices to greater than 80 percent.[123] (These technologies and others are explained in chapter 7.)

The potential for CHP in commercial settings may be quite large, with office buildings/retail, education buildings, and hospitals having the greatest potential (Figure 14). However, practical limits on thermal load matching and the utilization of waste heat may affect the potential of different building types. Hospitals are an ideal application, but hotels and other commercial buildings may be more difficult—though not impossible. The use of CHP microturbines has gained acceptance primarily in in-patient hospitals, hotels, and resorts. These facilities have large electrical loads and nearly as high thermal loads, for space heating, water heating, cooking, and laundry. These large and year-round thermal loads (in the case of all but space heating) provide a ready use for the waste thermal energy provided by the microturbine, allowing them to operate at near peak efficiency not only around the clock but 365 days per year. Nevertheless, there are many challenges to commercial CHP operations. To expand commercial CHP potential, policy is needed to support advanced technologies and innovative business models in this arena.

TABLE 1: Technology Comparisons

CATEGORY	10 MW NATURAL GAS CHP	10 MW PHOTOVOLTAIC ARRAY	10 MW WIND FARM	CENTRALIZED NATURAL GAS COMBINED CYCLE POWER PLANT (10 MW PORTION)
Annual Capacity Factor	85%	25%	34%	67%
Annual Electricity	74,446 MWh	21,900 MWh	29,784 MWh	58,692 MWh
Annual Useful Heat	103,417 MWht	0	0	0
Capital Cost	$24 million	$60.5 million	$24.4 million	$10 million
Annual Energy Savings	343,747 MMBtu	225,640 MMBtu	306,871 MMBtu	156,708 MMBtu
Annual CO_2 Savings	44,114 Tons	20,254 Tons	27,546 Tons	27,023 Tons

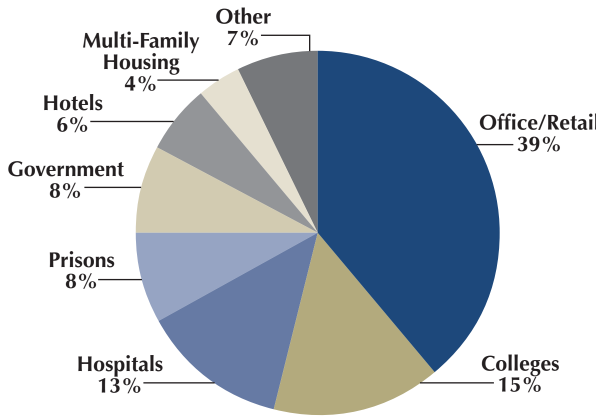
Source: ICF International 2012

Notes: A 10 MW Gas Turbine CHP –is assumed to have 30 percent electric efficiency and 70 percent total efficiency.

Electricity generation onsite is assumed to displace grid-supplied electricity generation of 9,720 Btu/kWh, with emissions of 1,745 lbs. CO_2/MWh; includes assumed 6 percent transmission and distribution losses.

Thermal generation on-site is assumed to displace an 80 percent efficient onsite natural gas boiler.

FIGURE 14: CHP Potential for Systems Greater than 1 MW to 33 GW, Percent of Potential Capacity



Source: ICF International 2012

Technological advances in gas-fired equipment are also needed. More affordable tank-less water heaters and combination space and water heating appliances can help reduce the market barriers to natural gas. Demonstration and deployment of such technologies can help natural gas utilities design the next generation of gas efficiency programs, provide whole-building solutions, and make natural gas service more attractive to customers and builders.

THE ROLE OF EFFICIENCY PROGRAMS AND STANDARDS

Current efficiency programs and federal efficiency codes and standards reduce greenhouse gas emissions from buildings in two important ways: by reducing the overall amount of energy used in buildings and by improving the baseline efficiency of specific appliances, equipment, and building stock. A third strategy could be to encourage the use of certain fuels, taking into account the total energy consumption of an appliance, the fuel used (full-fuel-cycle efficiency), and the associated greenhouse gas emissions. Historically, efficiency programs and standards have not considered full-fuel-cycle efficiency or the emissions reductions that could be achieved comparing across fuel types, although this is beginning to change, as in the case of appliance labeling described later in this chapter.

Conservation

At the broadest level, increasing the overall efficiency of new and existing buildings reduces the amount of fuel used of any type and is therefore beneficial. Energy efficiency minimizes energy use, and thus lowers greenhouse gas emissions. The United States has made remarkable progress in this regard. Energy use in buildings between 1972 and 2005 increased at less than half the rate of growth of gross domestic product, despite the growth in home size and the increased demand for energy from air conditioning and electronic equipment. But although great strides have been made, numerous untapped opportunities exist for further reductions in energy use and greenhouse gas emissions. Many of these require only modest levels of investment. Advances such as energy-efficient building designs and appliances provide quick payback to consumers through reduced energy bills. For example, new wall designs can minimize heat loss in buildings by as much as 50 percent by reducing the amount of framing used and by optimizing the use of insulated materials. The result is a diminished need for space heating—the largest energy use in a home.[124]

State and Local Building Codes

Building codes for new construction can improve the efficiency of buildings by ensuring that new technologies and methods are used that will reduce a building's energy use. Although new buildings constitute only 2 to 3 percent of the existing building stock in any given year, new construction practices have a compounding impact over time.[125] New construction can more easily incorporate novel energy efficiency technologies and is therefore often a harbinger of future trends. New building technologies are often introduced in the new construction market and then spill over into the arena of retrofits and renovation. Building codes can even affect a building's fuel options, for example, by encouraging or discouraging natural gas access by facilitating or slowing the approval of new, easier-to-install and less expensive indoor natural gas piping materials.[126.]

Low adoption rates for building codes are a barrier to the development of higher efficiency and lower emissions buildings. For example, in 1992 the commercial building code requirements of the Federal Energy Policy Act, which were based on 1989 industry standards, were met by only five states. By 2008, 40 states had statewide commercial building codes that met or exceeded the 1989 federal standards, but only 27 met the higher standards issued by DOE in 2004. This lead/lag effect in the setting and meeting of standards is indicative of a non-owner-operated building market that still places operating costs at a lower priority than construction costs. However, federal requirements are not the only drivers. California, for example, has set standards higher than those of the federal government, and some utilities, such as Austin Energy in central Texas, have worked with city governments to push standards and building codes beyond the industry norm.

Traditionally, building codes have been designed to look at the overall on-site energy usage of buildings. Accordingly, they are typically fuel-neutral, favoring neither natural gas nor electric appliances. As a result, building codes do little to take into consideration the full-fuel-cycle climate impacts of electricity versus natural gas and other fuels. Likewise, Leadership in Energy and Environmental Design (LEED) standards fail to take into account the relative full-fuel-cycle efficiencies of electricity, natural gas, and other fuels. LEED standards, developed by the U.S. Green Building Council, have been adopted by many municipalities, school districts, counties, and states for their new buildings, leading to an exponential growth in the number of LEED-certified buildings.[127] However, the U.S. Green Building Council is investigating ways to take these benefits into account, with particular focus on performance standards and nationwide applicability.

Appliance Standards

DOE is required by law to set minimum efficiency standards for appliances, and currently has standards that cover appliances and equipment responsible for 82 percent of home energy use and 67 percent of commercial energy use.[128] Appliance standards, first instituted in the 1980s and repeatedly strengthened since then, have greatly contributed to reducing appliance energy use and associated greenhouse gas emissions. However, appliance standards are based on the site efficiency of the appliance and do not consider the efficiency of the fuel. While this works well to encourage improved efficiency for each type of appliance, it does have implications for efficiency labeling programs and the ability of consumers to compare the true environmental performance of appliances using differing energy sources.

Appliance Labeling

Labeling programs such as ENERGY STAR strive to inform consumers about the energy consumption and energy cost implications associated with use of each appliance. ENERGY STAR uses a market-based approach having four parts: 1) using the ENERGY STAR label to clearly identify which products, practices, new homes, and buildings are the most energy efficient; 2) empowering decision-makers by making them aware of the benefits of products, homes, and buildings that qualify for ENERGY STAR, and by providing tools to assess energy performance and guidelines for efficiency improvements; 3) helping retail and service companies to easily offer energy-efficient products and services; and 4) partnering with other energy efficiency programs to leverage national resources and maximize impacts. The Environmental Protection Agency (EPA) estimates that in 2012 the ENERGY STAR program helped avoid more than 150 million tons of greenhouse gas emissions through encouraging the purchase of efficient products, with the amount of avoided greenhouse gas emissions increasing annually.[129]

While appliance labeling efforts like ENERGY STAR have educated consumers about the annual operating costs and site efficiency of appliances, current labels do not accurately or sufficiently connect consumers' economic interests with the environmental impacts of appliance use. Specifically, current labels do not inform consumers of the full-fuel-cycle efficiency of appliance models because the efficiency calculations are based on the appliance standards program, which again is based on site efficiency. As a result, consumers cannot compare the true quantity of energy required by each appliances or the true climate implications associated with using that appliance.

In 2009, the National Research Council released a report that recommended the gradual conversion of current labeling efforts to ones that would take full-fuel-cycle efficiencies into consideration. Full-fuel-cycle labeling will certainly be more challenging because it will require more data and analysis from appliance manufacturers, and the efficiency of an appliance will vary by geographical location because of different regional climates and power generation fuel mixes. However, as discussed earlier in this chapter, such information is essential to understanding the total amount of energy required to operate an appliance and the associated greenhouse gas emissions and will better equip consumers to make more informed choices when evaluating their appliance options.[130] In June 2011, DOE took the first steps toward a more regionalized labeling program with standards for furnaces and central air conditioning units that had a variable regional component.[131] In addition, in August 2012, DOE issued a policy amendment stating that it would begin consideration of full-fuel-cycle efficiency in setting future appliance standards and would work with the Federal Trade Commission to educate consumers about the full fuel cycle.[132]

While no appliance standards based on the full fuel cycle have yet been issued, if the success of current appliance standards and related labeling are any indication, moving to standards and labels based on full-fuel-cycle efficiency could move consumers to purchase appliances that use significantly less energy and provide a significant benefit to the climate.

ENERGY STAR for Buildings

In addition to having labels for appliances, EPA's ENERGY STAR program also assesses the efficiency of buildings and provides labels that allow comparison of energy usage across buildings. To be an ENERGY STAR-certified building, a variety of energy performance standards must be met and these differ by facility type. EPA provides tools to assess energy systems and management, building design, and a host of energy-related benchmarks to help building owners, architects, and even prospective tenants assess and make public the energy and cost implications of a building. In contrast to the appliance program, the ENERGY STAR program for commercial buildings does use primary or full-fuel-cycle efficiency to compare energy usage across building types.

Utility-Based Incentive Programs

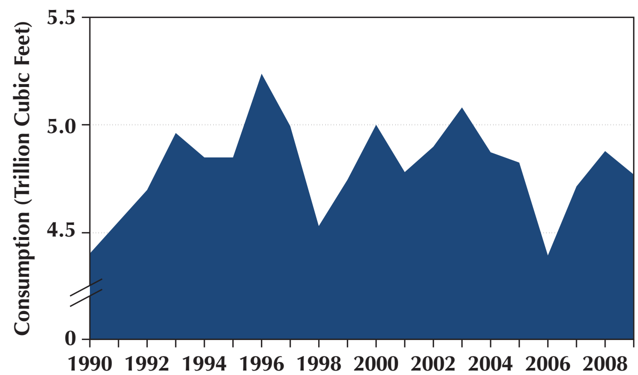
Utility-based financial incentive programs have been used since the early 1980s, when it became clear that information and education alone produced only limited energy and demand savings. Utilities have offered rebates, low-interest loans, and direct installation programs, and these have led to the accelerated market penetration of many energy-efficient building products such as attic insulation and high-efficiency appliances. However, these programs represent only a partial solution because not all states or all utilities offer such programs. More importantly, these incentives are based on site efficiency and are fuel-specific—since buildings are often served by separate electric and natural gas utilities, meaning that while incentive programs can encourage the efficient site use of a fuel, they do not allow consumers to compare fuel options based full-fuel-cycle efficiency. Thus, most utility-based incentive programs miss an opportunity to help consumers further reduce emissions.

BARRIERS TO INCREASED NATURAL GAS ACCESS AND UTILIZATION

The emissions benefits of natural gas use in homes and businesses will require greater access to the fuel for and within buildings. In 2005, 71 percent of U.S. homes had access to natural gas, and yet only 61 percent of U.S. homes made use of natural gas in an appliance. In addition, only 54 percent of new homes constructed in 2010 had natural gas service installed, and this access was primarily for heating and not necessarily for other natural gas appliances.[133] Similarly, in commercial buildings approximately half had natural gas access in 2003 (49 percent) and, as with homes, the use was primarily for heating.[134]

Annual consumption of natural gas in the residential sector has been declining since 1996 in spite of a growing residential customer base (Figure 15). Analysis by the Energy Information Administration suggests that the cause of this decrease is a combination of historically high natural gas prices from 2000 to 2009, which

FIGURE 15: Residential Natural Gas Consumption, 1990 to 2009



Source: Energy Information Administration, "Trends in U.S. Residential Natural Gas Consumption," 2010. Available at: http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf discouraged consumers from buying natural gas model appliances, a general migration of Americans to warmer climate zones with lower thermal loads, and an increase in home construction standards and appliance efficiency that reduced the amount of fuel consumed for the same purposes.[135]

Barriers to the Use of Natural Gas in Homes

The United States has, as a policy, pursued universal residential access to electricity for decades. Through taxpayer-funded rural electrification programs and customer-funded electric utility grid extension programs, the United States has achieved greater than 99.5 percent residential access to public or private electricity.[136] The same policy has not been implemented for natural gas.

When municipalities approve planning and development for new buildings, electric utility access is almost universally required through developer or utility funding, or a combination of the two. In contrast, running natural gas lines in new developments is often viewed as merely an option, and, as such, only 54 percent of new homes have natural gas access. In many cases, the decision is determined by financial analysis conducted by a local gas distribution company, or the combination local electric and gas utility, based on narrow first-cost criteria with little concern for the occupants' energy efficiency, operating cost, or greenhouse gas emissions. Prospective building owners often have little participation in this decision process. If the decision is made not to supply natural gas, retrofitted access to and within the building is significantly more expensive.

Even when natural gas infrastructure has been included in a new residential development, a homeowner may still be unable to choose how natural gas will be used in her home. Often, during architectural design and construction, the builder decides which appliances will have natural gas lines run to them, thereby "locking in" the decision and limiting consumer choice. In cases where the homeowner enters the process prior to construction, he may be offered a choice of appliance fuel options, but choosing natural gas may come at a cost premium for both the appliance and the cost of running the gas lines. In this choice, one between higher up-front costs of purchasing a home with gas appliances, on the one hand, and a lower long-term cost of operation (subject to gas prices), on the other, the immediacy of a slightly lower purchase price for electric appliances may prevail, even as low natural gas prices may lead to consumer savings in just a few years when compared to electric models.

Natural gas access, regulation, and price play important roles in residential fuel choice. The trend over the last decade, toward a lower percentage of new homes using natural gas, will have a long-term effect. Even though the trend was likely influenced by temporarily high gas prices, it effectively locks out the option for these "all electric" homeowners to benefit economically from what may be several decades of low natural gas prices as well as to benefit environmentally by lowering greenhouse gas emissions.

Moving beyond infrastructure constraints, an essential component shaping residential fuel choice is public education. For nearly a century, industry and government have portrayed electricity as a clean and efficient fuel, and it is—on site at the point of use.[137] Perceptions of natural gas are similarly affected by public opinion and government policy that focus on the point of use, which has not received the promotional policy that electricity has. This point-of-use perception is reinforced by the way in which most people interact with electricity and natural gas in their everyday lives: flipping a switch, turning on a burner, and paying a monthly bill. They rarely see or understand the generation side of electricity, the power plant, or the extraction and transportation of natural gas. Generally, the public has little basis for comparisons among fuels on issues of health, the environment, and the economy. Moreover, culture and family history can be important drivers of consumer choice, as individuals may be most comfortable with appliance types that they grew up with. Public education is critical for helping consumers understand the issues of efficiency and emissions and how they relate to common life choices, and to know what questions to ask when purchasing an appliance, renting an apartment, or buying a home.

Use of Natural Gas in Commercial Buildings

A significant barrier to the increased use of natural gas is the high percentage of non-owner-occupied commercial buildings, particularly office and warehouse floor space. On a floor-space basis, 49 percent of private commercial buildings are owner-occupied and 51 percent are non-owner-occupied.[138] Non-owner-occupied buildings are designed and built by real-estate developers who then rent or lease the space to tenants. The "for lease" building sector is extremely competitive, and rental cost per square footage is a key metric in attracting renters. In addition to paying rent, tenants may also pay utility or maintenance costs that may increase each year because of rising operating expenditures. Energy costs are a meaningful portion of these operating expenditures, but for billing purposes they are often combined with other costs, such as labor, water, and snow removal. Therefore, it can be difficult for tenants to discern specific financial benefits of energy efficiency upgrades, leaving building owners without a financial incentive to make such upgrades. This situation prevents lower operating costs from being reflected in market rental prices, since only exceptionally sophisticated tenants consider long-term gains from efficiency in rental decisions. In new buildings, owners' focus on achieving low rental costs can drive builders to prioritize construction cost over operating costs. This approach can preclude the installation of high-efficiency and lower-emission systems, including those that use natural gas on site for both electricity generation and heating applications.[139]

When energy efficiency upgrades are proposed for existing, occupied buildings, building owners may have the opportunity to recover capital outlays according to the terms of the leases. Most leases allow the installation of energy savings equipment or systems with cost recovery through amortization of the improvement over the life of the equipment installed. However, if a tenant does not renew her lease, a newly signed tenant cannot be charged the amortization; therefore, a portion of the cost of the project cannot be recovered. Since rents are based largely on market conditions and not by the operating costs incurred by the building owner, before owners undertake an energy efficiency project, they must evaluate what portion of the tenant base might leave before the project costs are recovered and what enduring benefits might accrue to the owner.[140]

Some low-cost energy efficiency upgrades can be treated as repair costs and added to the operating expenses within an existing lease. These stand-alone efficiency projects are very often subsidized with incentives from utilities. Projects of this nature usually have relatively short payback periods. The tenants see the benefit of the improvements very quickly, and the owner can justify the expense to the tenant regardless of whether the lease is renewed.[141]

In 2003, 46 percent of commercial buildings were owner-occupied, meaning they are designed and constructed for the owner's own use.[142] Compared to owners of leased buildings, owner-operators are more inclined to factor in the operating costs of their buildings because they have a long-term interest in the building and are concerned less with competitive rental markets. Therefore, they tend to install more energy-efficient systems and subsystem components as long as these have a payback period of 10 years or less. The government owners of 635,000 public buildings in the United States in 2003 share this focus on long-term operational costs and the advantage of higher efficiency systems; they may also have legal mandates or executive orders to reduce energy use and/or greenhouse gas emissions.[143] Owners constructing new buildings or performing retrofits, when faced with longer-term decisions about energy use and costs, will see expanded natural gas use as an attractive option, and large numbers of owner-occupied and government buildings using natural gas instead of electricity could yield significant emission reductions.

CONCLUSION

This chapter identified the full-fuel-cycle efficiency benefits and lower greenhouse gas emissions of the direct use of natural gas when compared to electricity, particularly for thermal loads. There is significant potential for increased direct use of natural gas in homes and businesses both in terms of increased access to new buildings and additional applications within buildings that already have access. In order for this potential to be fully realized, building standards, appliance standards, and appliance labels must take full-fuel-cycle energy use and associated emissions into account, and greater attention must be given to consumer education, regulatory changes, and increased access.

VI. MANUFACTURING SECTOR

By Michael Tubman, C2ES

INTRODUCTION

With prospects for cheap, abundant natural gas in the near and medium term virtually certain, demand for natural gas from manufacturing industries is expected to grow. In 2010, natural gas supplied 30 percent of the U.S. manufacturing sector's direct energy use, for combustion as well as non-combustion uses.[144] The U.S. Energy Information Administration forecasts that natural gas use in the industrial sector will increase by 16 percent between 2011 and 2025, from 6.8 to 7.8 trillion cubic feet.[145] Recent estimates indicate that $45 billion in new investment has recently occurred in chemical manufacturing alone. Lower natural gas prices are likely to provide a real economic advantage to U.S. manufacturing in the near and medium term.

The entire industrial sector (manufacturing and non-manufacturing industries combined) consumed 32 percent of all natural gas in the United States in 2011. This energy use emitted 401 million metric tons of carbon dioxide (CO_2).[146] This chapter examines the role of natural gas in the manufacturing sector today as well as its likely expansion, given forecasts of low and stable prices. With a resurgent and changing manufacturing sector comes the opportunity to reduce these emissions. This chapter also looks at promising strategies for reducing emissions include replacing older, less efficient industrial boilers and expanding the use of combined heat and power (CHP) systems.

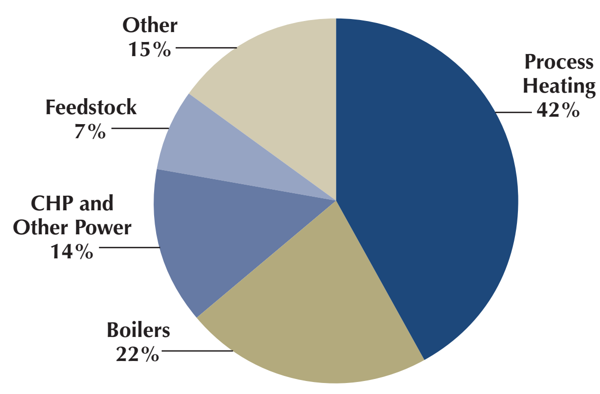
NATURAL GAS USE IN MANUFACTURING

The manufacturing sector includes diverse industries such as bulk chemicals, oil refining, and the production of steel, aluminum, cement, glass, paper, and food. It does not include the industrial activities of mining, construction, and oil and gas extraction. Natural gas usage within these industries varies significantly. It is used for heating and cooling; for process heat to melt glass, process food, preheat metals, and dry various products; and for on-site electricity generation (fueling boilers and turbines). Natural gas is also used as a feedstock (a material input) to make chemical products, fertilizers, plastics, and other materials.[147]

Overall, the largest direct use of energy by the manufacturing sector is for process heating, the production of heat directly from fuel sources, electricity, or steam that is used to heat raw material inputs during manufacturing. Natural gas is the dominant fuel used to generate heat, and process heating accounts for 42 percent of the natural gas use in the industrial sector overall (Figure 1). In 2010, process heating using all fuel sources produced 315.4 million metric tons of CO_2, which represents 40 percent of the CO_2 emissions for the entire manufacturing sector.[148]

Industrial boilers generating heat and steam are another large consumer of natural gas. Eighty-three percent of boilers run on natural gas, and they consume 22 percent of this fuel used in manufacturing.[149] While some are fueled by coal or other fuel, the dominant fuel

FIGURE 1: Natural Gas Use in Manufacturing, 2009

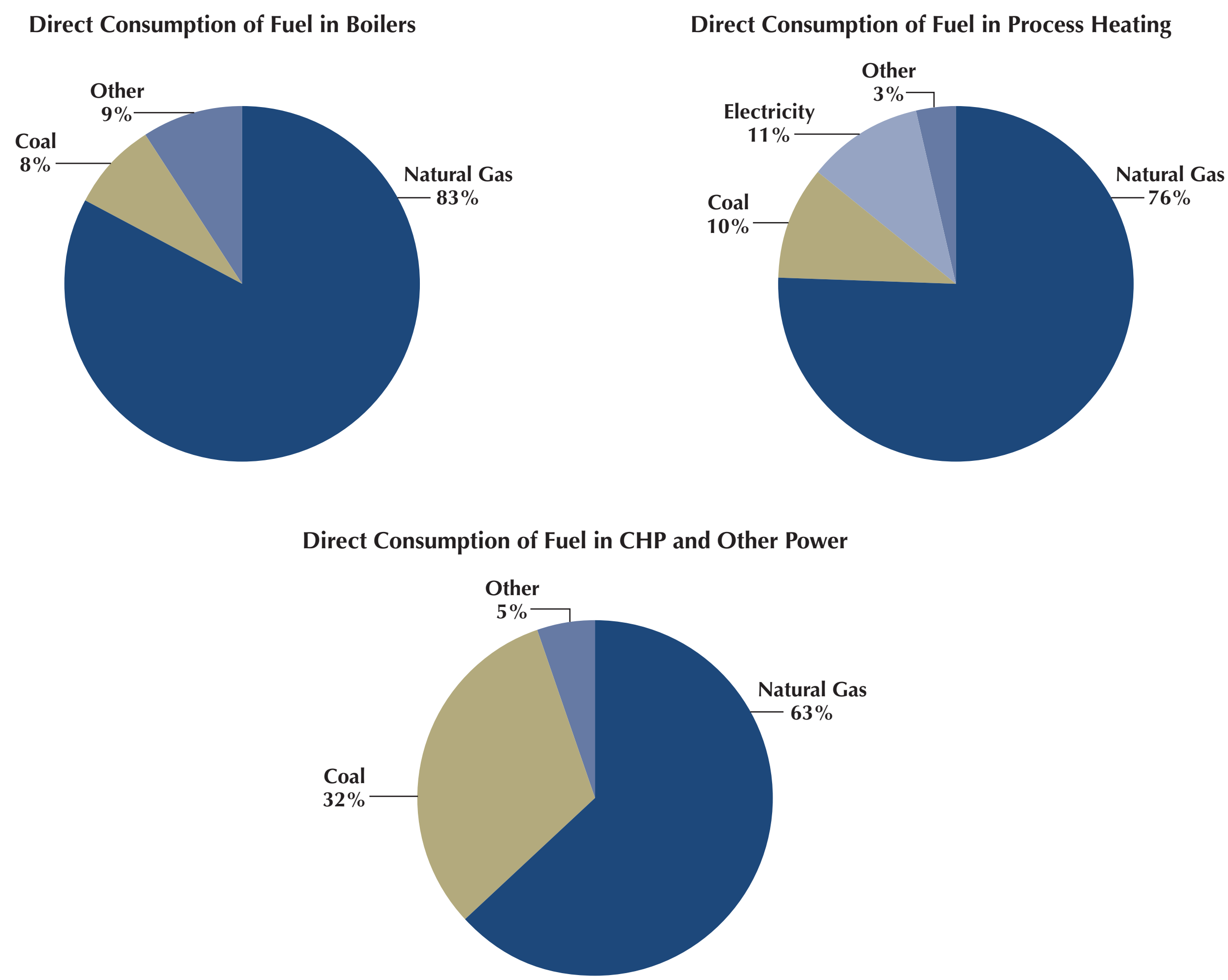


Source: Energy Information Administration, "Manufacturing Energy Consumption Survey," June 2009, Tables 2.2 and 5.2. Available at http://www.eia.gov/emeu/mecs/mecs2006/2006tables.html source is natural gas. Boilers are commonly used for a variety of purposes by chemical manufacturers, food processors, pulp and paper manufacturers, and the petroleum- and coal-derivatives industries (including chemicals, coke, and coal tar) (Figure 2).[150]

CHP—also known as cogeneration—is a third major use of natural gas in the manufacturing sector.[151] Natural gas is used to generate electricity on site, with the waste heat being captured and used for a variety of industrial purposes, greatly increasing the efficiency of the system overall. Additional efficiencies and emission reductions are also achieved through avoided transmission losses.[152] In 2010, 14 percent of natural gas used in manufacturing was consumed by CHP and other power systems. Natural gas is the most common fuel used for CHP systems. Nationwide, the added efficiencies of these systems avoid the emission of 35 million metric tons of CO_2 equivalent annually.[153]

Feedstock is raw material used as an input in manufacturing for creating value-added products. Natural gas production and its byproducts provide feedstock for the bulk chemicals industry, constituting a non-combustion use of natural gas. Methane—pure natural gas—is the source for hydrogen used in industrial processes, in fuel cells, and in the production of ammonia. Liquids extracted in association with natural gas, including ethane, propane, and butane, are processed and transformed to become other intermediate and final products including adhesives, insulation, paint, plastics, and vinyl.[154]

FIGURE 2: Direct Consumption of Fuels in the Manufacturing Sector, 2009



Source: Energy Information Administration, "Manufacturing Energy Consumption Survey," June 2009, Tables 2.2 and 5.2. Available at http://www.eia.gov/emeu/mecs/mecs2006/2006tables.html

Chemical companies are the largest consumers of natural gas-associated liquids, and they commonly use up to two-thirds of their delivered natural gas as feedstock.[155]

The emissions implications of using natural gas as a feedstock are very different from its other uses because feedstock use transforms hydrocarbon molecules into other products, rather than burning them. When natural gas is used as a feedstock, therefore, very low greenhouse gases emissions are produced. These low-emitting uses are enhancing U.S. competitiveness in the manufacturing sector. Whereas U.S. companies are reliant on low-cost natural gas liquids as a feedstock, European competitors use more expensive, oil-based naphtha.[156] In 2010, for example, domestic ethane sold at half the price of imported naphtha in Europe, and, consequently, U.S. chemical manufacturers have reaped a competitive advantage in international markets for intermediate and final goods.[157]

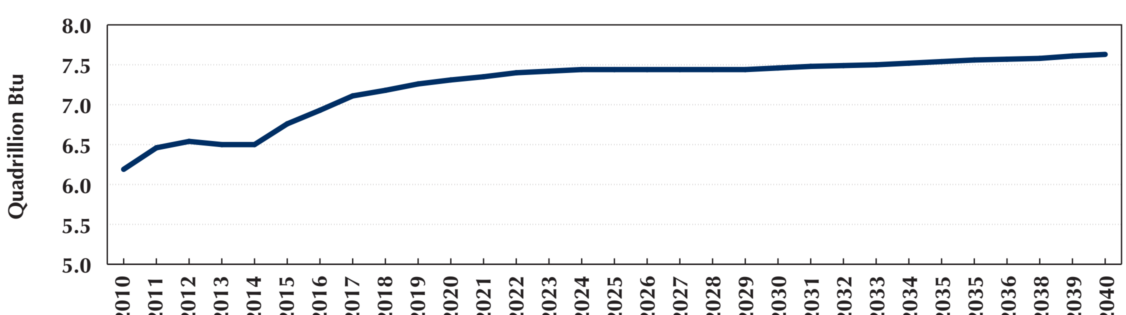
POTENTIAL FOR EXPANDED USE

Increased availability and low prices of natural gas have significant implications for domestic manufacturing. Large manufacturers dependent on natural gas for production are vulnerable to resource availability and price volatility. Accordingly, they have historically been concerned about policies or technologies that may impact these factors. Recently, abundant supply and low prices have led to greater confidence and an increase in domestic manufacturing, creating new jobs and economic value.[158] Numerous companies have cited natural gas supply and price in announcing plans to open new facilities in the chemicals, plastics, steel, and other industries in the United States,[159] including $41.6 billion worth of industrial investments that are planned between 2012 and 2018. One analysis has noted that the number of firms disclosing the positive impact of new gas resources for facility power generation and feedstock use increased substantially just between 2008 and 2011.[160] In 2010, exports of basic chemicals and plastics increased 28 percent from the previous year, yielding a trade surplus of $16.4 billion.[161] Continued low natural gas prices could have significant long-term economic benefits. A study by the American Chemistry Council estimates that a 25 percent increase in ethane supplies, for example, could yield a $32.8 billion increase in U.S. chemical production.[162]

EIA's Annual Energy Outlook 2013 Early Release of projections to 2040 reflects the expected increase in industrial natural gas demand. Total industrial consumption of natural gas for heat and power is projected to rise by 19 percent between 2010 and 2021 before increasing at a slower rate through 2040 (Figure 3). Efficiency measures are forecasted keep the amount of natural gas used per dollar of output declining over the same period (Figure 4).

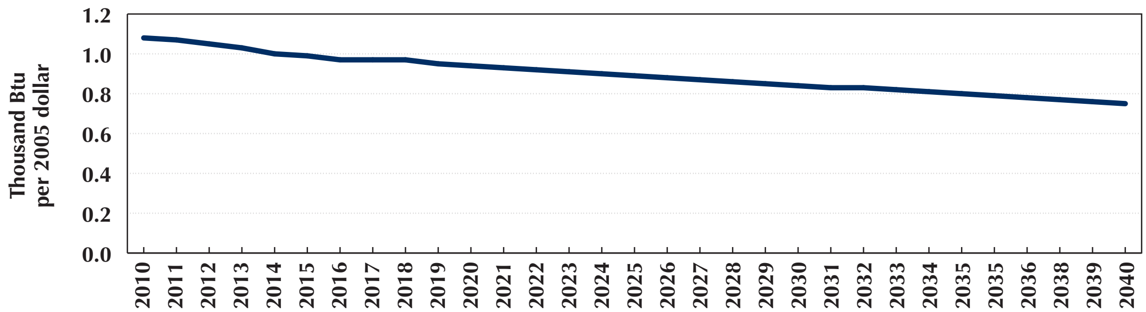
Total industrial consumption of feedstock (natural gas liquids) is projected to rise by 23 percent between 2010 and 2023 before declining from peak levels (Figure 5). Feedstock growth will be tempered by long-term changes in the natural gas market, including higher prices and international competition in chemicals manufacturing and future energy efficiency improvements expected to offset increased demand for feedstock while maintaining output levels (Figure 6). The use of CHP is projected to increase by 113 percent over the same period (Figure 7). Increases in the use of on-site electricity generation through CHP systems would partially reduce facilities'

FIGURE 3: Projected Total Industrial Consumption of Natural Gas for Heat and Power, 2010 to 2040



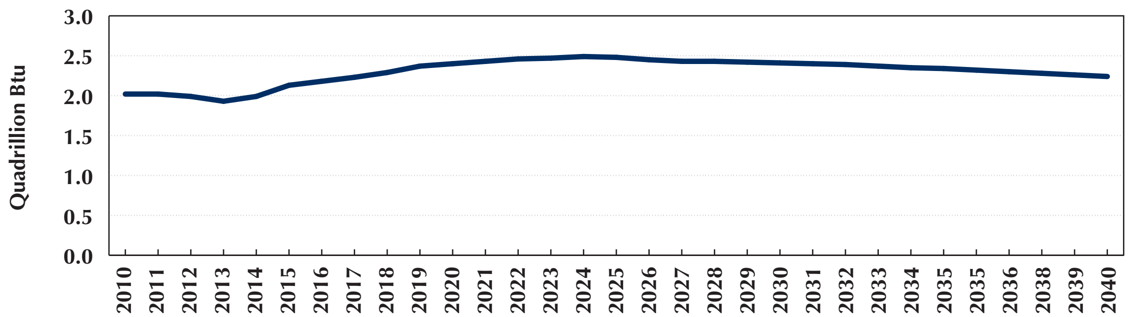
Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

FIGURE 4: Projected Energy Consumption of Natural Gas for Heat and Power per Dollar of Shipments, 2010 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

FIGURE 5: Projected Total Industrial Consumption of Natural Gas Liquids Feedstock, 2010 to 2040



Sources: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

reliance on grid-supplied electricity while providing heat for industrial uses. CHP systems are designed to balance heat production with electric power needs within a facility; electricity can be bought from the grid if needed, or sold to the grid if there is excess on-site production.[163]

These changes in the manufacturing sector will have mixed impacts on greenhouse gas emissions. Absolute increases in natural gas used for heat and power operations are likely to increase total emissions coming from the sector. However, improvements in energy efficiency and especially the substantial deployment of CHP operations will allow the manufacturing sector to increase output with relatively smaller increases in the amount of natural gas input.

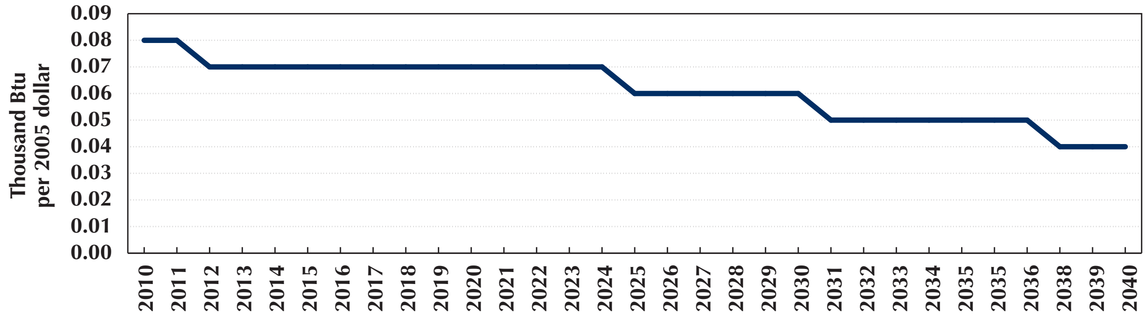
POTENTIAL FOR EMISSION REDUCTIONS

Even as the manufacturing sector expands, opportunities exist to reduce its emission intensity—the amount of CO_2 emitted per unit of output. Replacement of lower-efficiency boilers and greater deployment of CHP systems are ways to reduce emission intensity while using more natural gas.

Replacement of Lower-Efficiency Boilers

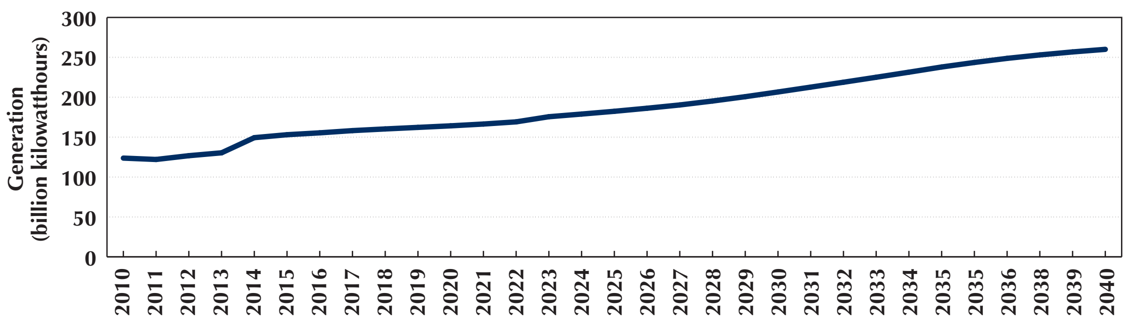
Improving the efficiency of industrial boilers is one such opportunity to reduce emission intensity. Boilers tend to have a low turnover rate, and older units are typically less efficient than newer ones. The pre-1985 fleet of boilers has an average efficiency of 65 to 70 percent, while new boilers have efficiency rates of 77 to 82 percent, and new, super-high-efficiency units can reach efficiencies of up to 95 percent.[164]

FIGURE 6: Projected Energy Consumption Natural Gas Liquids Feedstock per Dollar of Shipments, 2010 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

FIGURE 7: Projected Total Industrial CHP Generation for All Fuels, 2010 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

Analysis performed by the Massachusetts Institute of Technology found that replacing older natural gas boilers with high-efficiency or super-high-efficiency units would decrease CO_2 emissions by 4,500 to 9,000 tons or more per year per boiler. The analysis also found a strong economic incentive to make these replacements, highlighting annualized monetary savings of 20 percent (given certain assumptions, including 2010 natural gas prices) with a payback period for the new equipment of 1.8 to 3.6 years.[165]

While natural gas is the most commonly used fuel source for industrial boilers, 17 percent of boilers use coal or other fuels (Figure 2). Because of the air pollutants released from coal-fired boilers, these boilers are now subject to the U.S. Environmental Protection Agency (EPA) 2012 Maximum Achievable Control Technology standard (also known as the Boiler MACT). This standard requires the largest and highest-emitting boilers at industrial facilities, typically coal-fired boilers, to meet numeric pollution limits for the emission of air toxics, although it does not specifically require reductions in greenhouse gas emissions.[166] An analysis was performed to determine the results of replacing the Boiler MACT-affected coal boilers with efficient or super-high-efficiency natural gas boilers (natural gas boilers are not regulated under the new rule because of their already low emissions of the specified air toxics). This analysis found that replacement of coal boilers with natural gas boilers would reduce annual CO_2 emissions by 56 to 59 percent, or about 52,000 to 57,000 tons per year per boiler.[167]

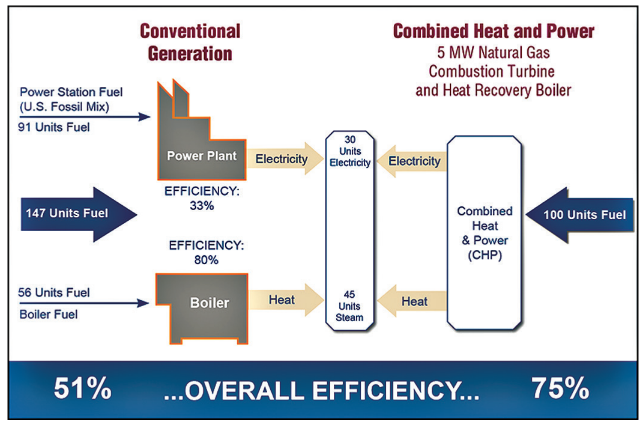
Expanded Use of Onsite CHP

Increasing the use of CHP also has the potential to reduce emissions produced in the manufacturing sector. An Oak Ridge National Laboratory study in 2008 calculated that increasing CHP's share of total U.S. electricity generation capacity from 9 percent in 2008 to 20 percent by 2030 would lower U.S. CO_2 emissions by 600 million metric tons compared with business as usual.[168] A study by McKinsey & Company in 2009 estimated that the potential exists for an additional 50.4 gigawatts of CHP capacity by 2020, which would avoid an estimated 100 million metric tons of CO_2 emissions per year compared with business as usual. Additionally, this study found that 70 percent of the potential cost-effective CHP capacity was through large-scale industrial cogeneration systems greater than 50 megawatts (MW).[169]

CHP units at industrial facilities have the added benefit of bolstering system reliability during a period of transition in the electric sector. Recent years have seen a wave of announced coal plant retirements, and power generation from natural gas-fueled CHP units could make up for some of this lost generation—with lower emissions than centralized coal power plants. A study from the American Council for an Energy-Efficient Economy found that natural gas-fueled CHP at industrial facilities could quickly and cost-effectively replace some of the electric power from retiring coal plants. In South Carolina and Kansas, it could replace all of the expected lost capacity, while in industrial, coal-dependent states such as Ohio and North Carolina, it could replace 16 and 56 percent of lost capacity, respectively.[170]

Figure 8 compares conventional, centralized power generation augmented with a boiler (left side) with a CHP system (right side). Each system is required to provide 30 units of electricity and 45 units of usable heat. However, the power station and boiler together require 154 units of fuel, and the CHP system requires only 100 units of fuel. Therefore, the power station is 49 percent efficient and the CHP unit is 75 percent efficient. At least 7 percent of the electricity delivered from the conventional power station to the industrial facility is lost during transmission. Although most of the losses occur as primary fuel-to-electricity conversion heat losses at the power plant, this heat is unable to be captured for useful purposes. Consequently, a boiler is required on the industrial site to create the necessary heat, which consumes additional fuel. In contrast, the CHP system is able to generate the electricity and heat together with far fewer losses. Since less fuel is required, overall emissions are lower. Some operations also use waste heat in an absorptive chiller to provide cooling services as well. Such operations are referred to as trigeneration or combined cooling, heating, and power. These operations offer even greater efficiencies and opportunities for emissions reductions.

FIGURE 8: CHP versus Conventional Generation



On the right, 100 units of fuel are converted into 30 units of electricity and 45 units of useful heat by a single CHP unit; 75/100 = 75 percent efficiency. On the left, 91 units of fuel are converted into 30 units of electricity by a large power plant and 56 units of fuel are converted into 45 units of useful heat by a separate boiler; 75/(91 + 56) = 51 percent efficient.

Source: Environmental Protection Agency, "Efficiency Benefits," 2012. Available at: http://www.epa.gov/chp/basic/efficiency.html.

BARRIERS TO DEPLOYMENT OF CHP SYSTEMS

Although CHP systems have dramatically higher efficiencies than grid power combined with simple natural gas combustion, and they result in much lower greenhouse gas emissions, barriers currently limit their application. Electric utilities often cite safety concerns as a barrier to deployment, specifically, perceived risks related to electricity being added to the grid outside of the central power plant. For example, some utilities cite the concern that miscommunication could occur between CHP operators and the utilities in the event of an emergency such as a storm causing downed power lines, which utilities say could lead to dangerous situations in which their line workers are not certain whether lines are energized or not. In addition, utilities may be concerned about risk and liability involved as their employees could be affected by safety and technical decisions of CHP operators, decisions they are concerned could be made independently of utilities.[171] Other concerns have to do with CHP systems' potential need for backup power. Many utilities are concerned about the need to provide backup power to industrial facilities if CHP systems are taken offline or are otherwise unavailable. For utilities, the ability to provide backup power requires capacity; to pay for investments in new or maintenance of existing capacity, utilities often charge CHP operators higher rates than other customers and additional interconnection fees to compensate for these necessary investments.

From the standpoint of industry, technical and economic considerations also may need to be taken into account when considering the installation of a CHP system. Some facilities may face shortages of trained CHP installers and operators. Another challenge is that CHP retrofits can be costly. Installation is easier during new construction or a major redesign of a facility. Lastly, some industrial users may face difficulties finding buyers for excess heat or power not needed for their own use. However, if buyers are found, the project may be not only environmentally sound, but economically viable as well.

Current regulatory and electric utility policies have inhibited the growth of CHP capacity, with its attendant climate benefits, because they prevent the alignment of financial interests between electricity producers and energy consumers. Power sector regulation in many states leads utilities to view CHP as unprofitable.[172] This negative view of CHP is often reflected in regulations established by public utility commissions that do not encourage new CHP deployment. However, innovative policy approaches can overcome this conflict between competing goals among utilities and CHP operators. One approach is decoupling, removing or modifying the link between a utility's volume of sales and its profits. Decoupling makes it profitable for utilities to encourage CHP systems.[173] Another potential policy solution is a lost-revenue adjustment policy, which compensates utilities through a charge on customer bills for revenues lost because efficiency measures were effective.[174, 175] State incentives can also encourage the use of CHP. State-level policies include standardizing grid-interconnection guidelines, offering tax incentives, and including CHP as a compliance mechanism for the state's clean-energy standards.[176] Some states have enacted these policies, and, as with many state-led policies, there is a diversity of approaches to (and success with) their implementation.[177]

An example of a state working to overcome barriers to CHP deployment is Ohio. The U.S. Department of Energy (DOE) estimates Ohio has a potential CHP capacity of up to 8,000 MW if CHP systems are installed and limited from selling power into the broader power market, and up to 11,000 MW if sales into the market are allowed. However, despite this vast potential, by 2011 only 766 MW of CHP was installed in the state.[178] Many of the boilers in Ohio will be affected by the new EPA 2012 Boiler MACT rule, making them candidates for upgrades or complete conversions to CHP systems. At the same time, new CHP facilities have the potential to address state regulators' concerns about several announced coal plant retirements affecting system reliability. In response to the benefits of CHP systems in Ohio at this time and to this technology's current underutilization, the Public Utilities Commission of Ohio launched a pilot project with DOE to encourage installation of CHP systems. This project identifies candidate systems and assists in the dialogue between potential CHP operators, utilities, and the electric market operator to facilitate installations while working to overcome regulatory and other barriers.[179] In 2012, the state legislature also added CHP systems as a qualifying resource in the state's clean-energy standard.[180]

CONCLUSION

The increased availability of low-priced natural gas has had positive economic impact on U.S. manufacturing and sector expansion is expected to continue. Given that natural gas is a feedstock and a fuel source for this industry, the efficient use of natural gas needs to be continually encouraged. Options to increase efficiency include the replacement of older boilers with more efficient ones and the expansion of CHP. CHP systems are highly efficient, as they use heat energy otherwise wasted. Policy is needed to overcome barriers to expanded deployment. States are in an excellent position to take an active role in promoting CHP when required industrial boiler upgrades and new standards for cleaner electricity generation are implemented.

VII. DISTRIBUTED GENERATION IN COMMERCIAL AND RESIDENTIAL BUILDINGS AND THE ROLE OF NATURAL GAS

By Doug Vine, C2ES

INTRODUCTION

Distributed generation is the production of electricity from smaller sources at or near the location where the energy will be consumed. Slightly more than 6.5 percent of electricity in the United States is generated at distributed locations outside of central generation plants.[181] Distributed generation using natural gas has a number of potential benefits, including the potential to capture heat associated with electricity generation that can be put to use on site. When waste heat is captured and used and/or highly efficient generation technologies are used, distributed generation decreases the total demand for primary fuels, thereby decreasing greenhouse gas emissions.

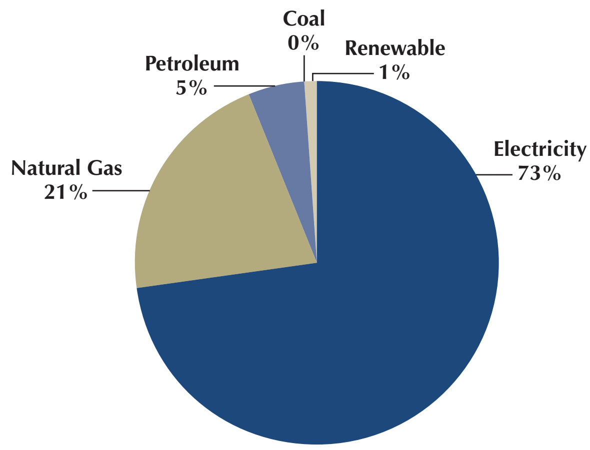
This chapter explores the potential climate-related benefits of distributed generation technologies as they apply to the residential and commercial sectors. (For a discussion of combined heat and power (CHP) systems in the manufacturing sector, see chapter 6.) The chapter discusses three major technologies for distributed generation: microgrids, fuel cells, and microturbines. Next, it explores policies that encourage the deployment of these technologies, and, lastly, it discusses barriers to deployment.

Electricity is the most widely used form of energy by residential and commercial buildings on a primary-energy basis (Figure 1). Since the majority of electricity generation emits greenhouse gases, it makes sense to consider technologies with lower emissions. Several promising technologies make use of natural gas as the primary fuel, and many of these technologies could significantly reduce greenhouse gas emissions from electricity use in the residential and commercial sectors. Distributed generation technologies either can be placed on site at a home or business or can be located a short distance away, serving several buildings together. While the majority of existing natural gas-fueled distributed generation technologies are not as efficient as central generation, the ones discussed in this chapter are highly efficient, can be used in highly-efficient configurations with CHP, and/or facilitate the deployment of renewable energy sources. Distributed generation technologies that supply power to multiple locations include microgrids. On-site or end-use technologies include natural gas-fueled electricity (and heating) devices such as fuel cells and microturbines, which can also be used as small CHP systems.

THE ADVANTAGES OF DISTRIBUTED GENERATION

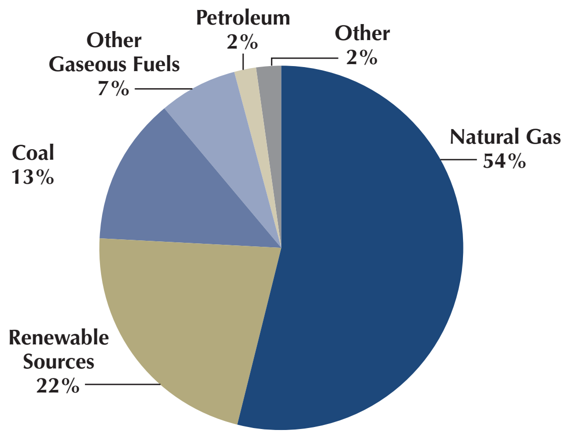
In 2010, natural gas-fueled electricity comprised approximately 54 percent of the total net U.S. distributed generation (Figure 2). These figures are for industrial and commercial sector distributed generation only and represent approximately 3.5 percent of the total electricity generated in that year.

FIGURE 1: Projected U.S. Residential and Commercial Buildings Primary Energy Consumption, 2010



Source: Energy Information Administration, Residential Energy Consumption Survey, 2009. Available at http://www.eia.gov/consumption/residential/data/2009/

FIGURE 2: Distributed Generation by Fuel Source, 2009



Source: Source: Energy Information Administration, Residential Energy Consumption Survey, 2009. Available at http://www.eia.gov/consumption/residential/data/2009/

Distributed generation has many advantages over centralized electricity generation, including end-users' access to waste heat, easier integration of renewable energy, heightened reliability of the electricity system, reduced peaking power requirements, lower greenhouse gas emissions, and less vulnerability to terrorism due to more geographically dispersed, smaller power plants.[182] In addition, producing electricity closer to where it is used reduces the amount of electricity lost as it is delivered over long distances from power stations to end users. Annual electricity transmission and distribution losses in the United States average about 7 percent of the electricity transmitted.[183] Lowering transmission (or line) losses means less electricity generation (less fuel and fewer emissions) is required to serve the same electrical demand.

Generally, natural gas-fueled distributed generation technologies are not as efficient in producing electricity as natural gas-fired generation from the grid. In general, distributed generation only improves efficiency and reduces greenhouse gas emissions when it includes CHP. By definition, distributed generation is physically located close to loads, so use of heat is often an option. However, CHP requires tight matching, in space and especially in time, between power generation and thermal loads. This matching can make CHP technologies difficult to effectively install. Nevertheless, where possible, this technology is significantly more efficient and should be deployed.

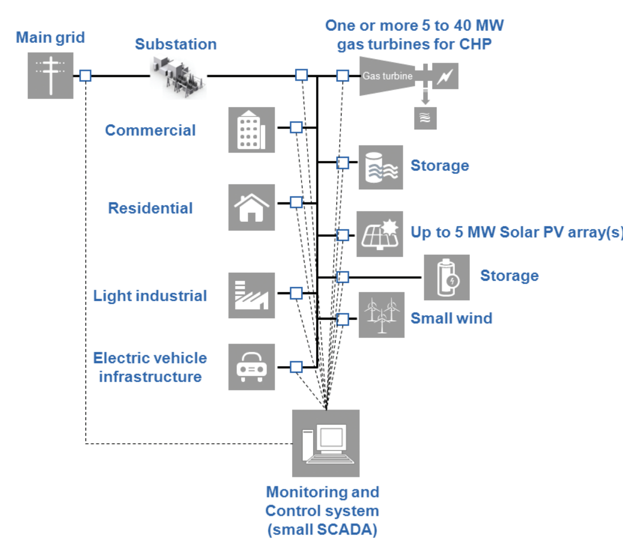
MICROGRIDS

One increasingly employed distributed generation technology is the microgrid. A microgrid is a small power system composed of one or more electrical generation units that can be operated either in conjunction with or independently from the central power system (Figure 3).[184] Microgrids can serve a small grouping of buildings. Additionally, microgrids offer the potential to integrate renewable sources of electricity with fossil fuel-based backup power; they are able to integrate distributed, dispatchable natural gas-fueled electricity (or CHP systems) with local renewable power and energy storage. Furthermore, since the electricity is generated close to where it will be used, it becomes feasible to use the waste heat in a productive manner, such as for heating water or space in nearby homes and businesses. Microgrids can be particularly attractive if new or upgraded long-distance electricity transmission cannot be developed in a timely or cost-effective fashion.[185]

FUEL CELLS

Fuel cells are another promising distributed generation technology. Natural gas-powered fuel cells use natural gas and air to create electricity and heat through an

FIGURE 3: Microgrid Concept



Source: Siemens, "The Business Case for Microgrids," 2011. Available at: http://www.energy.siemens.com/us/pool/us/energy/energy-topics/smart-grid/downloads/The%20business%20case%20for%20microgrids_Siemens%20white%20paper.pdf

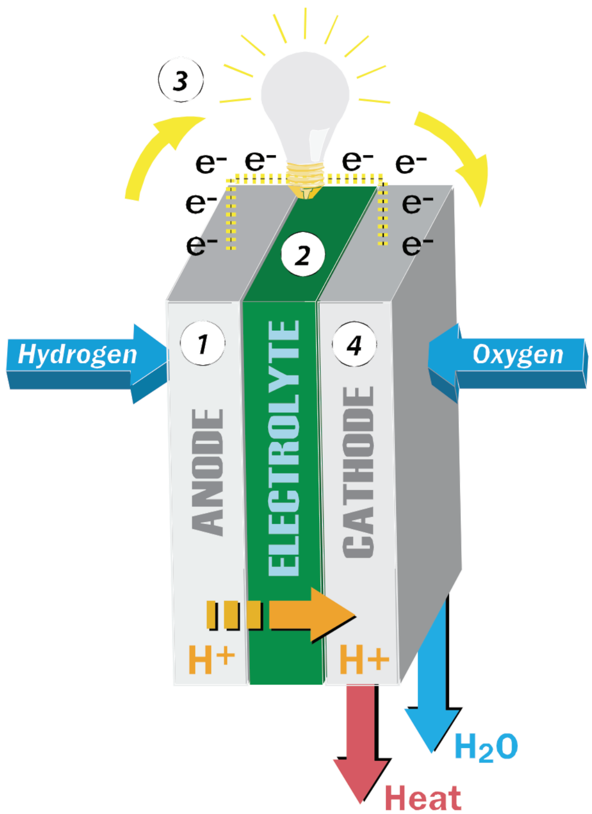
Note: Individual microgrid elements will vary.

electrochemical process rather than combustion.[186] First, natural gas is converted into hydrogen gas inside the fuel cell in a process known as reformation. When the hydrogen passes across the anode of the fuel cell stack (Figures 4 and 5), electricity, heat, water, and carbon dioxide (CO_2) are created.

Fuel cell technology has been around for many decades; it has been used by the National Aeronautics and Space Administration on space projects for nearly 50 years. Commercially available fuel cells operate in a wide range of climates, from very cold to very warm (-20° to 110°F), and they have electrical efficiencies of around 40 to 60 percent (Table 1). They are quiet devices with a fairly small footprint. The only greenhouse gas emitted is a pure stream of CO_2, which could allow for capture and sequestration. Despite these benefits, skeptics question the durability, cost (see below) and reliability of fuel cells. In the past, materials have corroded within months or a few years. Bloom Energy estimates that its current devices will have a 10-year life as long as the fuel stacks are replaced at least twice. However, since Bloom's introduction is recent, there are currently no operational fuel cell systems that have approached this age.[187]

There are many types of fuel cells, each with its unique chemistry, operating temperature, catalyst, and electrolyte.[188] Phosphoric acid fuel cells, molten carbonate fuel cells, and solid oxide fuel cells, among others, have been commercialized for stationary electrical power generation. Since many units operate at high temperatures and contain corrosive materials, a key concern is their durability or stack life. For example, natural gas-fueled phosphoric acid fuel cells operate at temperatures of around 450°F, and solid oxide fuel cells operate at temperatures of about 1,800°F.[189] Phosphoric acid fuel cells are the most durable type in the less-than-one megawatt (MW) range and have a demonstrated stack life of more than 10 years, although designs of many other fuel cell types are improving rapidly.[190]

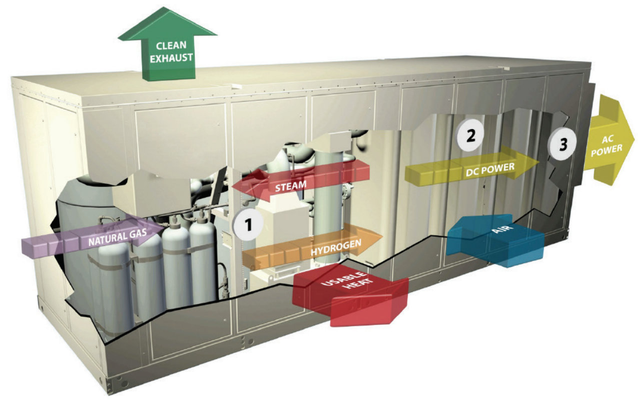
FIGURE 4: Fuel Cell Stack



1) Anode: As hydrogen flows into the fuel cell anode, a catalyst layer on the anode helps to separate the hydrogen atoms into protons (hydrogen ions) and electrons. 2) Electrolyte: The electrolyte in the center allows only the protons to pass through the electrolyte to the cathode side of the fuel cell. 3) External Circuit: The electrons cannot pass through this electrolyte and, therefore, must flow through an external circuit in the form of electric current. This current can power an electric load. 4) Cathode: As oxygen flows into the fuel cell cathode, another catalyst layer helps the oxygen, protons, and electrons combine to produce pure water and heat.

Source: ClearEdge Power

FIGURE 5: How Fuel Cells Work



Source: ClearEdge Power

Notes: 1) Fuel Processor: Converts natural gas fuel to hydrogen. 2) Fuel Cell Stack: Generates direct current (DC) power from hydrogen and air. 3) Power Conditioner: Converts DC power to high-quality alternating current (AC) power 4) Heat Recovery: On-board heat exchangers for recovering useful thermal energy.

ClearEdge Power and Bloom Energy are among a handful of manufacturers of stationary fuel cells. Their main products are described below for illustrative purposes. There are an additional half-dozen or so manufacturers of non-stationary fuel cells (fuel cells for vehicles).

ClearEdge Power, based in Oregon and established in 2003, manufactures refrigerator-sized fuel cell units that generate baseload or backup electric power as well as provide useable heat for hot water and/or space heating in a CHP configuration. These units are scalable to suit the energy requirements of individual homes, apartment buildings, hotels, and other commercial businesses, and can be installed indoors or outdoors. They have efficiencies of up to 90 percent. They are 50 to 60 percent efficient in natural gas conversion to electricity, in addition to providing useful heat. Therefore, they require considerably less natural gas to generate the same amount of energy provided from a combination of centrally generated electricity and a heating appliance.[191] In February 2013, ClearEdge Power acquired UTC Power, an early pioneer in fuel cell research that conducted experiments with many types of fuel cells beginning in the late 1950s.[192] Stationary fuel cell products from UTC Power, now ClearEdge Power, are deployed in residential, commercial, and industrial applications around the world.[193]

FIGURE 6: Bloom Energy Server Outdoor Installation

Source: Bloom Energy

Bloom Energy, based in California and founded in 2001, markets energy servers that consist of arrays of fuel cell boxes in various sizes that must be installed outdoors (Figure 6). The energy servers are scalable and are used by large corporate customers such as Wal-Mart, eBay, and FedEx, and not residential consumers.[194] These servers achieve conversion efficiencies above 60 percent. These are very high-temperature devices, but the heat is not used for water or space heating. The average emissions are 773 pounds of CO_2 per megawatt-hour (MWh), which is just below the average U.S. natural gas power plant at 800 to 850 pounds of CO_2/MWh.[195, 196]

MICROTURBINES

Microturbines are small combustion turbines approximately the size of a refrigerator with individual unit outputs of up to 500 kilowatts (kW).[197] These devices can be fueled by natural gas, hydrogen, propane, or diesel. In a cogeneration configuration (Figure 7), the combined thermal-electrical efficiency can be as high as 90 percent.[198] Like fuel cells, microturbines can achieve much higher energy efficiencies, because the electricity is generated close to the location where it will be used, and the heat byproduct can be captured and utilized on site or nearby.

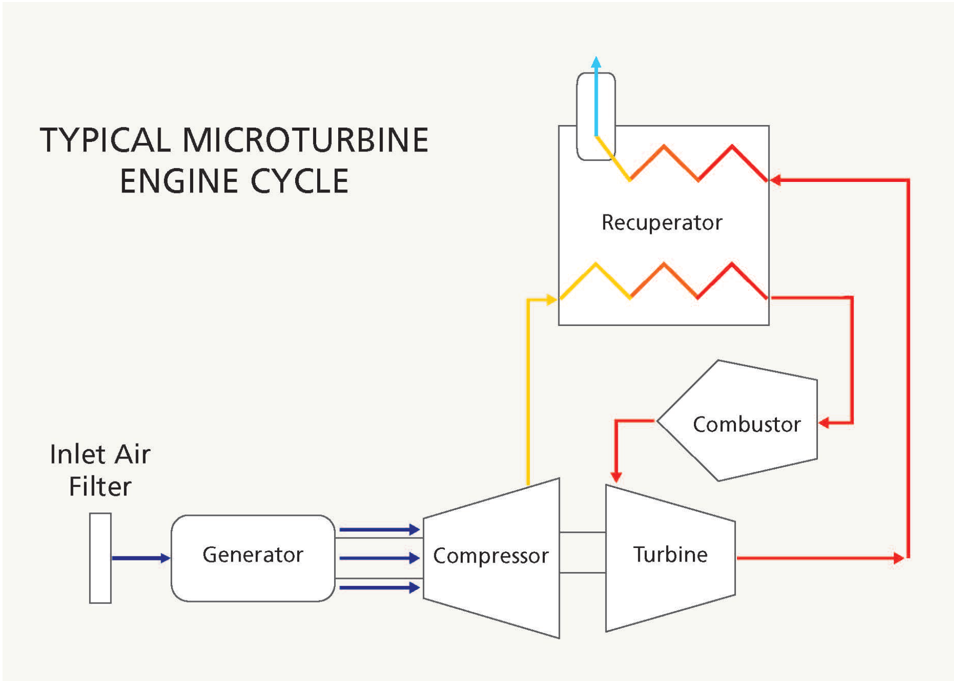
Microturbines are an established technology, and there are more than 20 companies worldwide involved

TABLE 1: Fuel Cells Summary

COMPANY	ELECTRICAL EFFICIENCY	USABLE HEAT	TOTAL EFFICIENCY FOR CHP SYSTEM	MARKETS
ClearEdge	50-60 percent	Yes	90 percent	Residential, Commercial, Industrial
Bloom Energy	60 percent	No	60 percent	Commercial

Source: Clear Edge, Bloom Energy

FIGURE 7: Microturbine Schematic



Fuel enters the combustor and the hot gases ejected from the combustor spin a turbine, which is connected to a generator that creates electricity. The exhaust gases transfer heat to the incoming air. A recuperator captures waste heat and helps improve the efficiency of the compressor.

Source: Capstone Turbine Corporation

in the development and commercialization of microturbines for distributed generation applications.

Los Angeles-based Capstone Turbine Corporation is a global market leader in the commercialization of microturbines.[199] The company offers individual units in the range of 30 kW to 200 kW, and greater quantities of power can be achieved by using multiple units, with electrical efficiencies from 25 to 35 percent (Figure 8). Using the heat produced by a microturbine for water or space heating, space cooling (in conjunction with absorption chillers) and/or process heating or drying, increases the efficiency of these units to 70 to 90 percent.[200] Capstone products service the commercial and industrial sectors, and they have installations all over the world, including universities, a winery, and a 35-story office tower in New York City (Figure 9).[201]

Flex Energy, also headquartered in California, is Capstone's main competitor. Its 250 kW microturbine has an electrical efficiency of 30 percent, and it too provides useful heat energy, which when used would improve the overall efficiency of the system.[202] Flex Energy and Capstone microturbines can use low-quality

FIGURE 8: Microturbine Unit

Source: Capstone Turbine Corporation

FIGURE 9: Microturbine Installation

Source: Capstone Turbine Corporation

and unrefined natural gas, making them capable of generating electricity at landfills and hydraulic fracturing sites.[203] Using unrefined natural gas at a well site for power requirements can reduce the need for diesel power generation and utilize natural gas that may have been flared otherwise.

Micro Turbine Technology, a company in the Netherlands, is developing a 3 kW electrical with 15 kW thermal microturbine CHP for homes and small businesses that is expected to be ready for market in early 2013.[204]

At 31 percent average electrical efficiency, much lower than a modern natural gas combined-cycle plant or fuel cell (both around 50 percent), microturbines produce 1,290 pounds of CO_2/MWh, about 50 percent higher emissions than a modern combined-cycle plant.[205] However, due to their ability to capture and use waste heat onsite, they are capable of achieving thermal efficiencies of up to 85 percent. When this heat is captured and used, the total efficiency of the system offsets the lower efficiency of electricity generation part of the system, reducing overall greenhouse gas emissions per MWh. Additional strengths of microturbines include their compact size, small number of moving parts, generally lower noise than other engines, and long maintenance intervals. Weaknesses include parasitic load loss from running a natural gas compressor and loss of power output and efficiency with higher ambient temperatures and elevation.[206] According to U.S. Environmental Protection Agency data, at an 80°F outdoor air temperature, the microturbines are about 3 percent less efficient than at a 50°F outdoor air temperature.[207]

RESIDENTIAL UNIT CHP

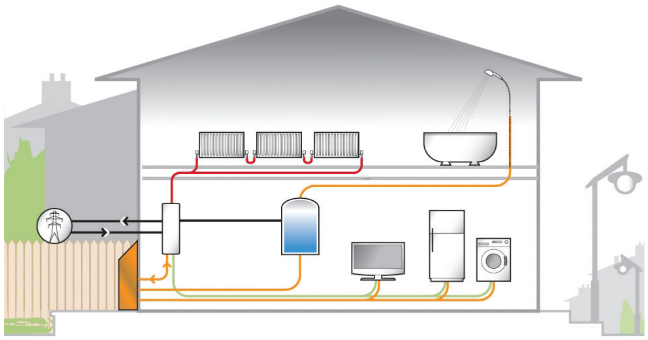
There are even smaller systems than the microturbines discussed that can provide CHP to individual residential units. At less than 50 kW, these microCHP units are small enough to provide electric power for a residential or commercial building while also supplying heat for thermal applications or absorption cooling (Figure 10). Common in Europe and Japan, microCHP is rare in the United States. These small units may use a variety of engine types, including combustion, steam, Brayton, and Stirling.[208] For example, the WhisperGen, developed in New Zealand, is a microCHP technology based on the Stirling engine. The company is currently headquartered in Spain, where the product is being marketed to European customers. The washing machine-sized technology is designed to produce hot water and space heating. Under normal operation the unit will provide around 1 kW of electrical power.[209] Other companies, such as Japan's Honda, also offer microCHP units to consumers.[210]

TABLE 2: Microturbine Summary

COMPANY	ELECTRICAL EFFICIENCY	USABLE HEAT	TOTAL EFFICIENCY FOR CHP SYSTEM	MARKETS
Capstone	25-35 percent	Yes	70-90 percent	Commercial, Industrial
Flex Energy	30 percent	Yes	Not Available	Commercial, Industrial
MTT	N/A	Yes	Not Available	Residential

Source: Capstone, Flex Energy, MTT

FIGURE 10: Residential CHP Unit



Residential CHP unit (bottom left outside of house) is capable of supplying hot water and heating as well as electricity to several appliances. Home is still grid connected for any consumption unable to be met by the CHP unit and excess power generated by the unit can be sold back to the electric utility.

Source: Fuel Cell Today

POLICIES TO ENCOURAGE THE DEPLOYMENT OF NEW TECHNOLOGIES

Although these new technologies have great potential to use less primary energy and to reduce greenhouse gas emissions from energy use in the residential and commercial sectors, there are some hurdles to overcome. Higher upfront capital costs hinder investment in distributed generation technologies overall. In addition, utility regulations often do not encourage, and in some case actively discourage, distributed generation technologies.

Some state and federal incentive programs help home- and business-owners with upfront costs. At least 10 states provide financial incentives for self-generation.[211, 212] The federal Investment Tax Credit, designed to help defray capital expenditure costs, applies to fuel cells, CHP, and microturbines for use in the commercial, industrial, utility, and agricultural sectors.[213]

Another potential incentive for consumer investment in on-site energy generation is net metering. Net metering allows customers to receive retail prices for their excess generation; the electricity meter turns backwards (literally or digitally) when the site generates more electricity than it consumes.[214] Forty-three states and the District of Columbia have rules enabling net metering.[215] Eligible generation technologies vary. Fuel cells using any fuel type often qualify, and CHP sometimes qualifies, although less often.

Sites using distributed generation often rely on a grid interconnection as a source of backup power. Establishing a connection between an on-site system and the power grid can be difficult, confusing for the on-site operator, and lengthy. Standard interconnection rules greatly simplify this process, establishing clear and uniform processes and technical requirements that apply to all utilities within a state. These rules reduce uncertainty and prevent delays that installers and operators of distributed generation systems can encounter when obtaining approval for electric grid connection, and thus make the prospect of installing a system less daunting to newcomers.[216] As of April 2012, 34 states had interconnection standards for fuel cells, and 29 states had such standards for microturbines.[217]

A final area where policies could encourage the installation of more distributed generation systems pertains to utility charges. As mentioned above, distributed generation systems rely on a grid connection for backup power during outages, whether scheduled or emergency. Standby rates are charges levied by utilities when a distributed generation system must purchase all of its power from the grid. These charges generally include an energy charge, reflecting the actual energy provided, and a demand charge, which is a way for the utility to recover its costs in maintaining the capacity to meet the facility's peak demand whenever that may be required. Utilities often argue that the demand charges act as a strong incentive for system owners to manage their peak demand. However, the likelihood of unplanned outages during times of peak demand is very low, and the use of demand charges likely discourages the expansion of distributed generation. Regulators should carefully weigh the discouraging effect of demand charges against the substantial benefits of distributed generation, including increased system reliability, reduced distribution losses, and the climate benefits of the higher system efficiencies.[218]

BARRIERS TO DEPLOYMENT

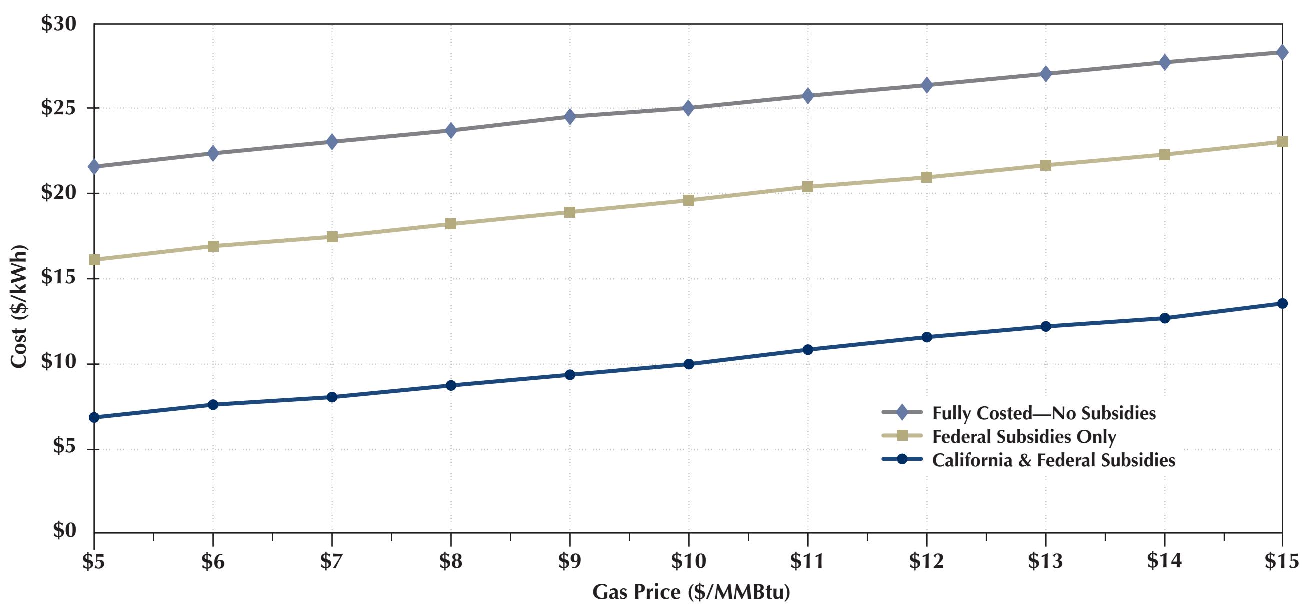
A variety of factors converge to discourage potential owners of distributed generation systems. First, consumers are largely unfamiliar with these technologies. Moreover, they are not compelled to search for innovative strategies to generate energy. Their utility bills are stable, due to low wholesale electricity prices (a result of lower natural gas prices). Local building and fire codes may also provide disincentives or even make it impossible for consumers to consider distributed generation. And the limited availability of many distributed generation products in the United States is a barrier to even those with natural gas access.[219]

Even if these hurdles are removed, the cost of many distributed generation technologies can be a barrier. According to the National Institute of Building Sciences, microturbine capital costs were $700 to $1,100 per kW in 2010, with installation costs adding 30 to 50 percent of the total installed cost. Combining heat recovery technology to units increased the cost by $75 to $350 per kW. A future cost below $650 per kW may be possible with future economies of scale.[220] Fuel cells could be cost-competitive with grid electricity if they were to reach an installed cost of $1,500 or less per kW; however, the current installed, unsubsidized cost is at least $4,000 per kW.[221] Nevertheless, a combination of state and federal incentives, low natural gas prices, and high grid-electricity prices could result in a 100 kW energy server making economic sense, as shown in an analysis by Seattle City Light (Figure 11). Similarly, natural gas microCHP units could be cost competitive with a 1.5- to two-year payback period at an installed cost of $1,500 for a 1 kW unit.[222]

CONCLUSION

To realize the potential of distributed generation technologies, policies such as financial incentives and tax credits will need to be more widespread. Additionally, net metering, grid interconnection requirements, and standby rate issues will need to be worked through. Also, low consumer awareness and higher costs of these emerging technologies will slow their deployment. Finally, utilities may perceive distributed generation technologies as a threat, as they have the potential to capture a large share of utilities' electricity sales business. Nevertheless, some supporters of distributed generation have claimed that their technology will replace the grid and have designed their business strategies accordingly.[223]

FIGURE 11: Bloom Energy Server Cost Depends on Gas Price and Subsidies



Source: Seattle City Light, "Integrated Resource Plan." 2010. Available at: http://www.seattle.gov/light/news/issues/irp/docs/dbg_538_app_i_5.pdf

VIII. TRANSPORTATION SECTOR

By Fred Beach, The University of Texas at Austin

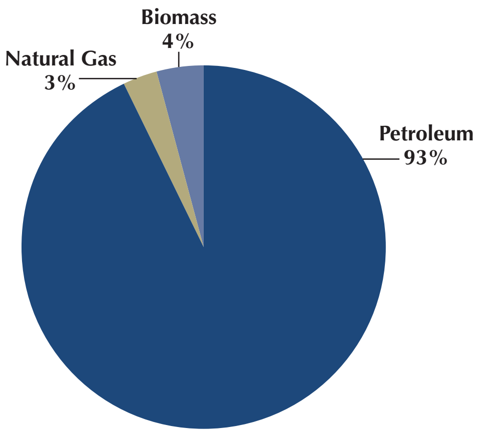
INTRODUCTION

Historically, natural gas has not been widely used as an energy source for transportation; rather, the sector has long been dominated by petroleum use. In 2010 (Figure 1), the U.S. transportation sector used 27.47 quadrillion British thermal units (Btu) of energy, of which 25.59 quadrillion came from petroleum and just 0.72 quadrillion came from natural gas—93 percent and 3 percent of the sector, respectively.[224] Natural gas used in the transportation sector resulted in the emission of just 40.1 million metric tons of carbon dioxide equivalent (CO_2e) in 2010, out of a total 1,746 million metric tons emitted by all fuel sources in the transportation sector.[225] As in other sectors of the economy, fuel substitution from other fossil fuels to natural gas in some parts of the transportation sector has the potential to yield climate benefits. In addition, it would benefit U.S. national security by decreasing reliance on the global oil market. Although the potential for natural gas use is less in the transportation sector than in others, the potential does exist, primarily for medium- and heavy-duty trucks as well as fleet vehicles and buses.

A main driver of the increased interest natural gas fleets and passenger vehicles is the relative abundance and low price of domestic natural gas in comparison to oil. On April 30, 2012, the national average price of diesel fuel was $4.07 per gallon and gasoline cost $3.83 per gallon,[226] while a gasoline-gallon-equivalent of natural gas cost only $2.09.[227] On the same day, the price of petroleum was $104.87 per barrel,[228] and the price of natural gas was only $12 on an energy-equivalent basis.[229] In recent years, oil prices rose while natural gas prices decreased, creating an ever-widening gulf (Figure 2). This differential has made natural gas vehicles increasingly economical.[230]

This chapter looks at the currently available natural gas technologies for vehicles. Next, it explores the barriers to adoption for various types of vehicles. Finally, it examines the potential implications of broader direct use of natural gas in the transportation sector for greenhouse gas emissions.

FIGURE 1: Energy Sources in the U.S. Transportation Sector, 2010



Source: Energy Information Administration, "Annual Energy Review," Table 2.1e. October 2011. Available at: http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0201e

AVAILABLE NATURAL GAS TRANSPORTATION TECHNOLOGIES

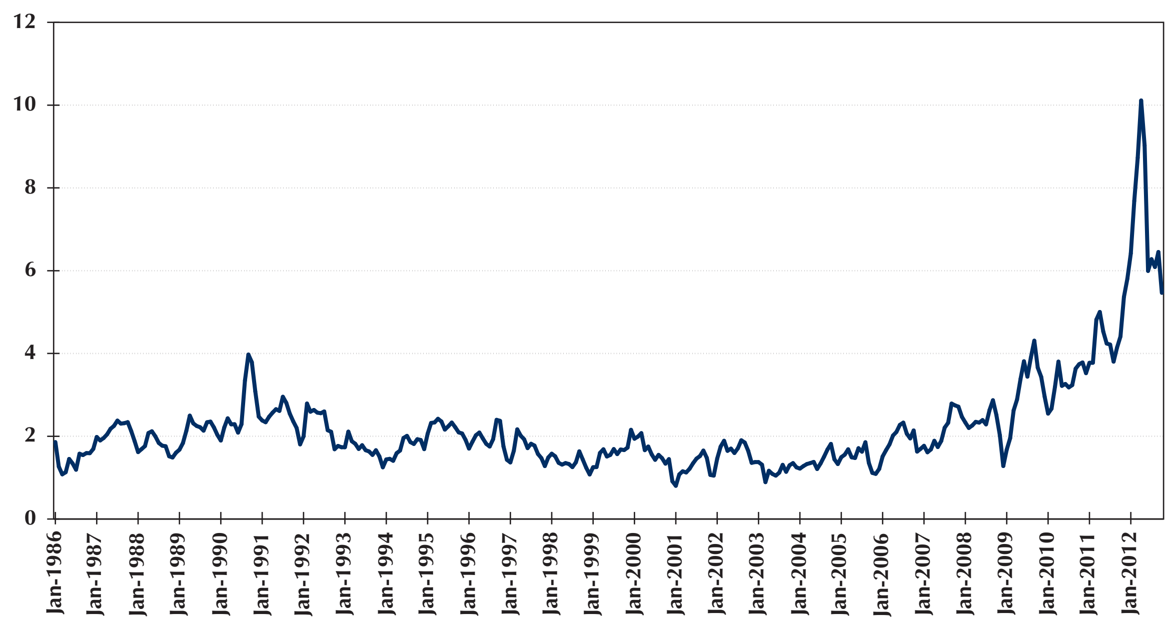
A variety of available vehicle technologies allow natural gas to be used in light-, medium-, and heavy-duty vehicles. Most commonly, natural gas is used in a highly pressurized form as compressed natural gas (CNG) or as liquefied natural gas (LNG). While CNG and LNG are ultimately burned in the vehicle, natural gas can also power vehicles in other ways. Natural gas can be converted into liquid fuel such as gasoline and diesel (distinct from LNG) that can be used in conventional internal combustion engines, reformed into hydrogen for use in fuel-cell vehicles, or be used to generate electricity for electric vehicles. Despite the existence of these technologies, only about 117,000 of the more than 250 million vehicles on the road in 2010 (about 0.05 percent) were powered directly by natural gas.[231] The majority of natural gas-powered vehicles are buses and trucks.[232]

Compressed and Liquefied Natural Gas

CNG is the most common natural gas fuel used in transportation today. There were 115,863 compressed-natural gas vehicles on U.S. roads in 2010, using 988 fueling sites.[233] The majority is found in larger transportation fleets. Although Honda offers a CNG passenger vehicle, only 4,000 vehicles were scheduled for production in 2012.[234] Public transit buses are the largest users of natural gas in the transportation sector, with about one-fifth of buses running on CNG or LNG. Some commercial fleets use natural gas-powered trucks, including thousands of trucks at FedEx, UPS, and AT&T.[235, 236] Waste Management has the largest fleet of natural gas vehicles in the country with 1,700 trucks that can run partially on biogas supplied from its own landfill assets.[237] The low cost and environmental benefits of this biogas are encouraging the company to continue conversions and to open some of its refueling infrastructure to the public.

To a lesser extent than CNG vehicles, vehicles powered by LNG (primarily heavy-duty trucks) are also used on U.S. roads and a fueling infrastructure has begun to develop. LNG is created by chilling natural gas to -260°F at normal pressures, at which point it condenses into a liquid that occupies 0.0017 percent of the volume of the gaseous form.[238] The conversion of natural gas to LNG removes compounds such as water, carbon dioxide (CO_2), and sulfur compounds from the raw material, leaving a purer methane product whose combustion results in less air pollution.[239] The stable, non-corrosive form also makes LNG more easily transportable, and it can be moved by ocean tankers or trucks.[240] Use of LNG requires large, heavy, and highly insulated fuel tanks to keep the fuel cold, which adds a significant cost to the vehicle.[241] Today, LNG is mainly used as a replacement for diesel fuel in heavy-duty trucks because they can accommodate this hefty storage system and can use LNG fueling infrastructure currently limited to trucking routes.[242] In 2010, there were only 40 public and private LNG refueling sites,[243] serving 3,354 LNG vehicles.[244] Recently, the Clean Energy Fuels network launched the development of an interstate LNG refueling network, mainly taking advantage of existing diesel fueling

FIGURE 2: Oil Price as a Multiple of Natural Gas Prices, 1986 to 2012

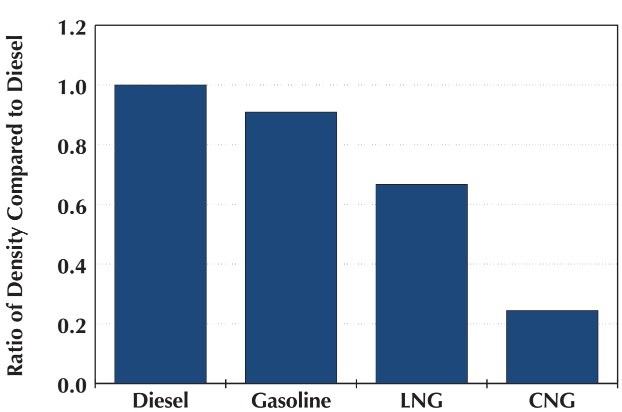


Source: Energy Information Administration, "Annual Energy Outlook 2012 Early Release," 2012. Available at: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=EARLY2012&subject=0-EARLY2012&table=7-EARLY2012&region=0-0&cases=full2011-d020911a,early2012-d121011b

stations along highways and trucking distribution centers. Seventy stations were opened in 2012, with plans for 70 to 80 more in 2013.[245]

CNG and LNG are less dense forms of energy than conventional gasoline and diesel fuel (Figure 3), requiring vehicles running on them to have larger fuel tanks in order to store the same amount of energy. CNG requires special storage because the gas is compressed to less than 1 percent of its volume at standard atmospheric pressure.[246] Vehicles use cylindrical storage tanks capable of fuel pressures of up to 3,600 pounds per square inch. These tanks are significantly larger and heavier than conventional gasoline or diesel fuel tanks, and their placement in passenger vehicles can take up valuable passenger or trunk space.[247, 248] The energy density of CNG is so low that CNG vehicles with ranges greater than 300 miles are unlikely to be produced unless current space and weight limitations are overcome. Therefore, CNG is primarily suitable for fleet passenger vehicles, municipal buses, and other vehicles where travel distances are shorter. The greater energy density of LNG, however, makes it practical for long-haul tractor-trailers that can accommodate larger fuel tanks.[249] Despite being less energy-dense than gasoline or diesel, both CNG and LNG can be an attractive fuel source for certain applications, from both an economic and environmental perspective.

FIGURE 3: Comparison of the Energy Density of Natural Gas and Diesel Fuel



Source: Energy Information Administration, "Annual Energy Outlook 2010 with Projections to 2035," 2010. Available at: http://www.eia.gov/oiaf/aeo/otheranalysis/aeo_2010analysispapers/factors.html

Fuel Cell-Powered Vehicles

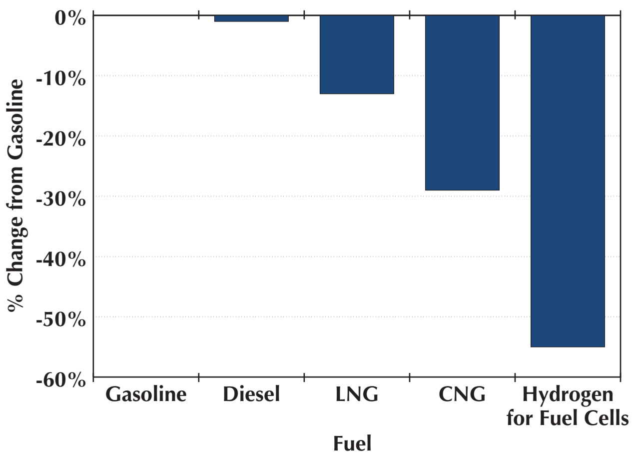
Natural gas also plays a role in supplying fuel cell vehicles (see chapter 7 for a discussion of stationary fuel cells in distributed generation). Fuel cells produce electricity through an electrochemical process rather than through combustion, resulting in heat and water and far lower emissions of greenhouse gases and other pollutants. Fuel cells are fueled by hydrogen, and the most common source of hydrogen today is natural gas. Hydrogen can be extracted on board the vehicle using a reformer, or it can be externally extracted and subsequently added to the vehicle.[250] Today, no light-duty fuel cell vehicles are commercially available in the United States, although there are certain test vehicles on the road as well as rudimentary hydrogen fueling infrastructure in California.[251] Companies are working to introduce fuel cell vehicles to the market. In the United States, Hyundai plans to build 1,000 fuel cell vehicles for distribution in 2013,[252] and Toyota has suggested that production costs are decreasing such that it should be able to sell fuel cell vehicles for $50,000 by 2015.[253]

Gas to Liquids

While CNG and LNG are today the most common forms of natural gas fuels in vehicles, other available technologies could increase the use of natural gas in the broader transportation system. Gas-to-liquids technology refines natural gas into gasoline or diesel hydrocarbons, which can be used in existing vehicles and moved through existing infrastructure. Gas-to-liquids products have energy densities similar to those of traditionally produced gasoline and diesel, properties that allow for better engine performance and potentially fewer emissions of greenhouse gases and regulated pollutants,[254] although more empirical study is needed on emissions.

Conversion technologies typically require 10 thousand cubic feet (Mcf) of natural gas to produce one barrel of oil-equivalent product output, such as diesel, naphtha, and other petrochemical products.[255] Using $4 per Mcf of natural gas as inputs to this conversion, the outputs are equivalent to $40 per barrel of oil-equivalent. Gas-to-liquids products have been produced at facilities elsewhere in the world, and new facilities in the United States are being developed. Several companies are considering gas-to-liquids facilities on the Gulf Coast because of favorable natural gas supplies and current domestic prices.[256]

FIGURE 4: Full Lifecycle, Total Carbon Intensity of Selected Transportation Fuel Options as a Percentage Reduction from Gasoline Carbon Intensity



Source: California Air Resources Board, "Proposed Regulation to Implement the Low Carbon Fuel Standard," March 5, 2009. Table ES-8. Available at: http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf

Notes: The carbon intensities compared above were calculated specifically for California's Low Carbon Fuel Standard program using the GREET model.

Results from the GREET model rely on the assumptions included in the model. Other models may use other assumptions and yield different results. Models are useful for insights, but their results depend on the assumptions made.

Electric Vehicles

Natural gas also plays a role in electric vehicles, which are becoming more common on U.S. roads. These vehicles use electricity from the electrical grid, which is increasingly powered by natural gas as a fuel source. From January 2011 to December 2012, Americans purchased more than 60,000 plug-in electric vehicles, including Chevrolet Volts, Nissan LEAFs, and Toyota plug-in Priuses.[257] Additionally, plug-in electric vehicles are now available from BMW, Ford, Tesla, Mitsubishi, and Daimler.[258] When fueled by electricity generated by a combined-cycle natural gas power plant, such natural gas-powered electric vehicles offer significant efficiency and emissions benefits over conventional diesel- or gasoline-powered vehicles.[259]

GREENHOUSE EMISSIONS OF NATURAL GAS AS A TRANSPORTATION FUEL

Transportation accounts for more than 25 percent of U.S. greenhouse gas emissions and is an important focus of U.S. emission reduction efforts. Natural gas emits fewer greenhouse gases than gasoline or diesel when combusted or used in fuel cells (Figure 4). Fuel Cells offer the greatest potential emission reduction benefit but today are also the most expensive. CNG offers the next largest greenhouse gas reduction potential and can be used in many transportation options including fleets, heavy-duty vehicles and passenger vehicles. The barriers and potential for emission reductions associated with fuel switching to natural gas in major segments of the transportation sector are described below.

NATURAL GAS IN BUSES AND MEDIUM- AND HEAVY-DUTY VEHICLE FLEETS

Buses produce a very small share of overall greenhouse gases, contributing only 1 percent of emissions from on-road vehicle transportation in 2011, but as previously mentioned, they are the most common use of natural gas in vehicles today.[260] In contrast, long-haul tractor-trailers play a more important role in U.S. energy consumption and greenhouse gas emissions. These vehicles account for two-thirds of all fuel consumption for freight trucks (medium- and heavy-duty trucks), and freight trucks' emissions are increasing more rapidly than those of other transportation sources. Over time, freight trucks will likely account for an even larger percentage of the sector's greenhouse gas emissions, as they will take on a greater portion of deliveries for consumer products, using more vehicles for just-in-time shipping and taking advantage of lower labor costs and changing land use patterns.[261] Consequently, reducing the carbon intensity of freight trucks will be critical to reducing transportation sector greenhouse gas emissions, and increased natural gas use is one opportunity to do so.

Barriers to Expanded Natural Gas Use

Significant barriers exist for the expansion of natural gas use in medium- and heavy-duty vehicles. Currently, trucks utilizing CNG or LNG have shorter ranges, fewer refueling options, and lower resale value than traditional diesel-powered trucks. A diesel truck with a 150-gallon tank and a 6 to 7 miles-per-gallon fuel economy can travel about 1,000 miles on one tank, which is significantly more than its natural gas-powered counterparts. Depending on the mounting of the cylindrical storage tanks, CNG trucks can travel between 150 miles and 400 miles between fueling, while LNG trucks can travel around 400 miles.[262]

The limited availability of fueling infrastructure also hampers the deployment of natural gas-powered trucks, and better infrastructure is required for greater use.[263] In May 2012, there were 1,047 fueling stations for CNG and 53 fueling stations for LNG in the United States, and 53 percent of the CNG stations and 57 percent of the LNG stations were closed to the public.[264] Also, speed of fueling can be a barrier to deployment in certain fleet types, as the more common and less expensive fueling technology requires long filling times. On-time delivery operations of trucking fleets may not be able to accommodate long filling. Slow filling is more appropriate for trucks such as waste trucks or buses that may idle for long periods overnight or between uses.[265]

Fuel pricing differentials are a clear driver for natural gas conversions in the transportation sector since fuel costs are a significant portion of the overall operating budgets for fleet owners. Medium-duty trucks use about 6,000 gallons of fuel per year, while heavy-duty trucks use about 18,000 gallons. At $3.50 per gallon of diesel fuel, annual fuel costs are $21,000 for a medium-duty truck and $63,000 for a heavy-duty truck. Natural gas fuel costs are substantially lower than diesel fuel. At a price of $2.80 per diesel gallon equivalent—a typical price for LNG or retail CNG—annual fuel costs would fall to $16,800 per medium-duty truck and $50,400 per heavy-duty truck. At a slow-fill CNG cost of $1.00 per diesel-gallon-equivalent, costs drop to less than one-third the cost of diesel, to $6,000 per medium-duty truck and $18,000 per heavy-duty truck. These fuel savings offer great incentives for fuel-switching.[266]

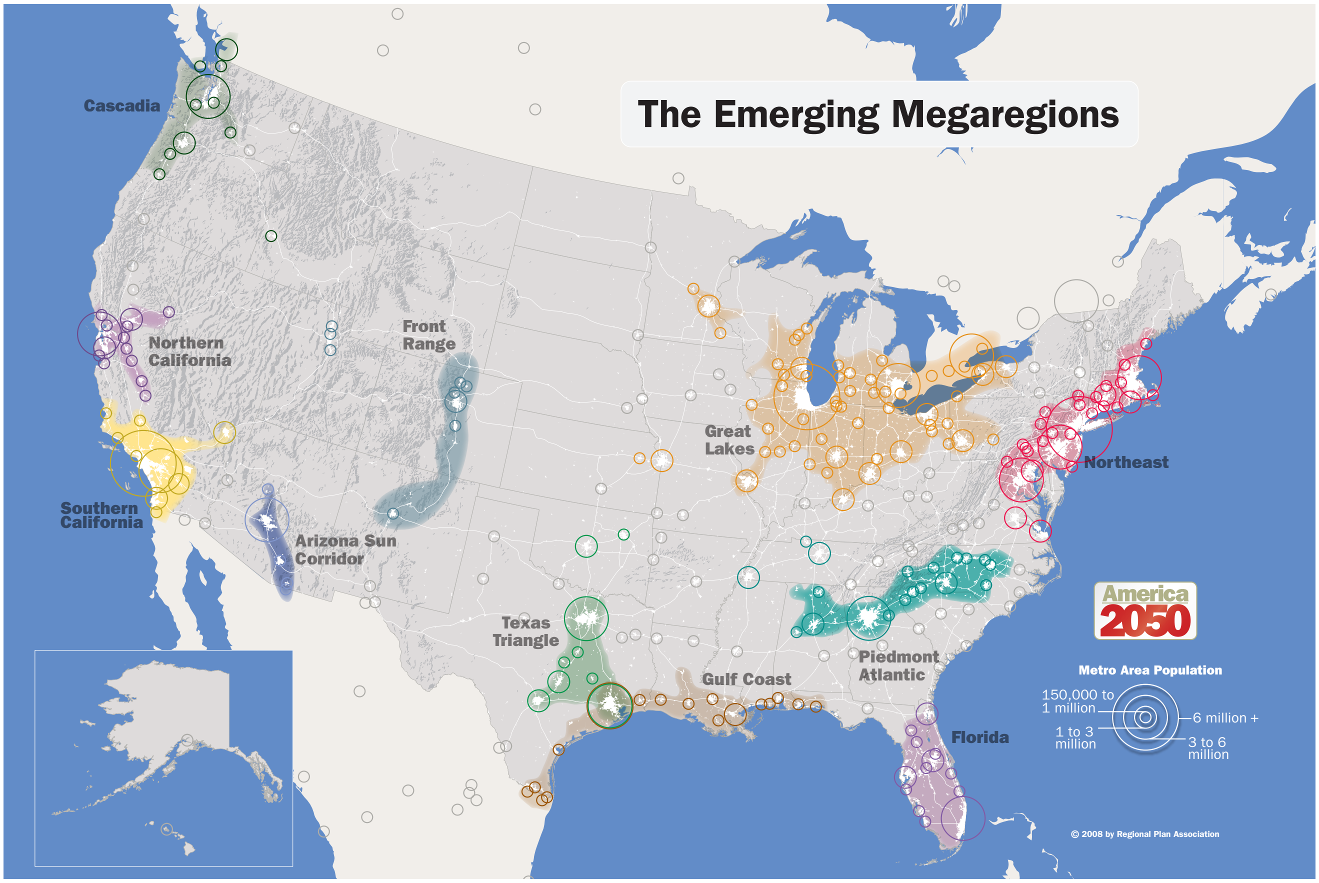
However, fleet economics are often more complex, extending beyond just fuel costs. Natural gas trucks are about $30,000 to $50,000 more expensive than their diesel counterparts, a substantial additional capital cost. Adoption of natural gas trucks also requires fleet owners to invest in additional maintenance capacity for natural gas vehicles, requiring investments in new materials and job training. Complying with standards for maintaining natural gas trucks, such as those required under Occupational Safety and Health Administration regulations for compressed gases, adds costs.[267] These costs may further rise as regulations for this nascent industry develop and change. Resale value of natural gas trucks is another important factor for some fleet owners. Trucks from some large fleets may be resold in as little as three to four years, often to smaller trucking companies that may not be able to use natural gas vehicles due to a lack of available infrastructure or a skilled workforce. As a consequence, even with the potential fuel savings, many fleet owners may have little economic incentive to switch to natural gas trucks.

Overcoming Barriers

The cost-benefit ratio of CNG vehicles for fleet owners depends on the many variables inherent in the composition and use of vehicle fleets and the costs of refueling infrastructure. For fleet owners, range requirements may not be a significant issue, since fleet vehicles travel regular and known paths. Refueling can take place at a centralized facility or along a set route.[268] The U.S. Department of Energy's National Renewable Energy Laboratory conducted research into three different types of CNG fleets that might be used by municipal governments—transit buses, school buses, and refuse trucks—and possible refueling infrastructures. This segment was targeted based on the potential for long-term cost-effectiveness, consistency of operational costs, lower greenhouse gas emissions, and other factors.[269] The research led to the creation of a model for fleet profitability that highlighted the importance of fleet size and vehicle miles driven in calculating the cost and benefits of CNG vehicles. It estimated payback periods of three to 10 years that were sensitive to the costs related to refueling stations and vehicle conversion, operations, and maintenance.

This model includes the cost of building and operating centralized fleet-specific refueling infrastructure and thus avoids the "chicken versus egg" refueling quandary that is challenging to non-municipal fleet applications, such as small private trucking operations. The lack of a public CNG refueling infrastructure hinders fleet owners' decisions to convert heavy-duty vehicles to CNG. Conversely, the low numbers of heavy-duty vehicles converted to CNG dampens private and public sector investor motivation to build CNG refueling infrastructure. Were it not for the lack of a public refueling infrastructure, the rationale for fleet owners to convert heavy-duty vehicles would be much more compelling, as their high annual miles driven provide a much quicker

FIGURE 5: Emerging Megaregions with High Tractor-Trailer Usage



Source: Regional Plan Association, "Maps," 2012. Available at: http://www.america2050.org/maps/

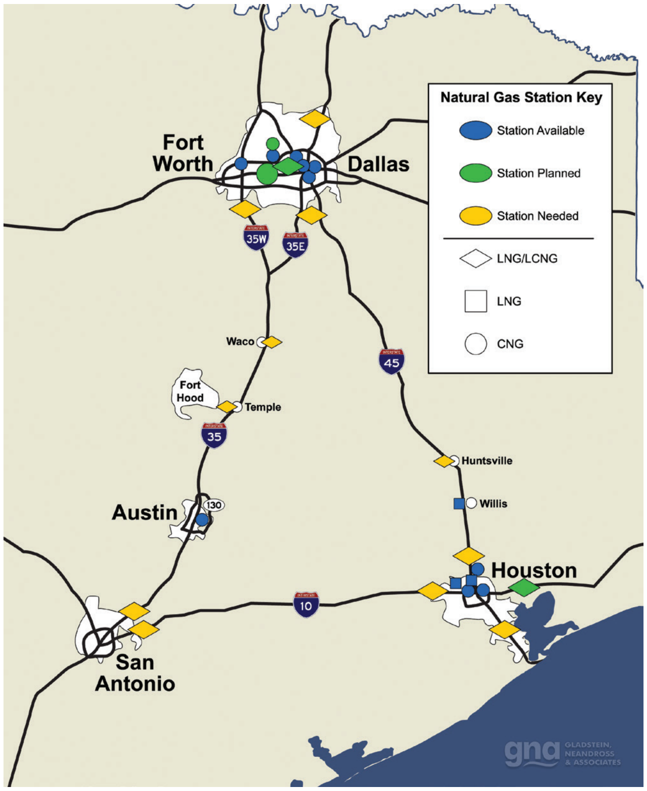
return on the upfront cost of vehicle conversion than do the annual miles driven of municipal fleet vehicles.

One approach that may help to overcome the vehicle-conversion-versus-refueling-infrastructure hurdle is to focus on one subset of the high-mileage, heavy-duty tractor-trailer industry segment, namely, intercity (as opposed to interstate) transport. In intercity regions with areas of high tractor-trailer usage, a very small number of public CNG refueling stations can serve a large number and percentage of the heavy-vehicle transportation segment. The United States has 11 "Megaregions" where tractor-trailers travel tens of thousands of miles annually but never leave the confines of a relatively small geographic area (Figure 5). Natural gas infrastructure can be built out in these Megaregions, such as through the proposed Texas Clean Transportation Triangle (Figure 6). Nearly 75 percent of the intrastate heavy and medium transport in Texas occurs within the triangle, making it an excellent candidate for CNG infrastructure.[270] Nominal public refueling infrastructure for CNG vehicles in the 11 Megaregions could also prove sufficient to service the interstate CNG tractor-trailer segment for a significant portion of the nation and create enough consumer demand to encourage the installation of refueling capability throughout the nation's network of commercial truck stops.

NATURAL GAS IN PASSENGER VEHICLES

Passenger vehicles account for nearly three-fifths of the total energy use and greenhouse gas emissions in the transportation sector. The lower price of natural gas and the energy security benefits of reducing U.S. consumption of oil have both contributed to recent interest in using natural gas in passenger vehicles.

FIGURE 6: Texas Clean Transportation Triangle



Source: Gladstein, Neandross & Associates / America's Natural Gas Alliance

Barriers to Deployment

Potential barriers to wider deployment of natural gas-powered passenger vehicles include lack of access to refueling sites and the vehicles' limited ranges.[271] Home refueling is one way to potentially increase the number of refueling sites. While there are 159,006 retail gasoline stations in the United States,[272] more than 65 million U.S. homes have natural gas service.[273] Home refueling of a CNG vehicle requires the installation of a wall-mounted electric compressor to deliver the low-pressure gas from the residential system into the high-pressure CNG vehicle tank. The compressors are small and unobtrusive, but require several hours to fill the vehicle's tank.[274] Home refueling options may, in addition to providing lower fuel prices, persuade some consumers to consider purchasing CNG passenger cars or to convert existing ones from gasoline-powered cars. Yet, home fueling infrastructure has remained expensive. Home fueling appliances, such as Phil, can cost more than $4,000,[275] not including the construction and permitting costs of extending home natural gas pipe access to the garage or carport. Other barriers to adoption exist. CNG vehicles, when compared with conventional gasoline vehicles, have a reduced range because of CNG's lower energy density (the maximum range of the Honda Civic GX NG is 248 miles),[276] higher up-front costs, and smaller trunk capacity.

Fleets including taxis, business, and government vehicles may offer the greatest potential for natural gas use in passenger vehicles. In 2012, 22 states signed a memorandum of understanding to jointly solicit automaker proposals to produce seven categories of natural gas vehicles for purchase by state, local, and municipal fleets. The intention of this joint effort is to stimulate the market for natural gas vehicles and eventually expand opportunities for market growth in the private sector for passenger natural gas vehicles, as well as to decrease the fleets' associated air pollution.[277] Combined, the barriers associated with the deployment of light-duty natural gas vehicles are noticeably larger and more costly than those associated with CNG- and LNG-powered heavy-duty vehicles.

Energy Security

Increased use of these vehicles offers significant potential benefits to U.S. energy security. Energy security is the adequacy and resiliency of the energy system as it relates to energy production, delivery, and consumption. The U.S. transportation sector relies on a global oil market that is currently dominated by an oligopoly—the Organization of the Petroleum Exporting Countries (OPEC)—as well as national oil companies. OPEC's ability to constrain supplies results in oil prices higher than a competitive market would produce. Monopoly power, combined with oil price shocks, mean that the U.S. economy loses hundreds of billions of dollars per year in productivity. Researchers at the Oak Ridge National Laboratory estimate that the combined total of these costs has surpassed $5 trillion (in 2008 dollars) since 1970.[278] Moreover, most experts believe that rising demand in emerging market economies coupled with supply-side challenges can be expected to lead to future volatility in oil prices, which would be highly damaging for U.S. consumers and businesses. Replacing oil with domestically produced natural gas would have significant benefits for U.S. energy security.

CONCLUSION

The transportation sector has long relied on petroleum fuels for the vast majority of its energy needs. While utilizing natural gas as a fuel source in this sector offers greenhouse benefits, in total these benefits are less likely than in other sectors of the economy, given the difficulty, cost and speed of converting passenger vehicles to natural gas. Moreover, in the near and medium term, fuel economy for gasoline-powered passenger vehicles is set to rise due to new Corporate Average Fuel Efficiency Standards, which could reduce the emissions advantage of natural gas vehicles. Hybrid and electric passenger vehicles are also becoming more common, and given the widespread availability of electricity compared to the availability of natural gas, they require less infrastructure investment than do natural gas vehicles. These factors indicate that, considering the need for substantial long-term reductions in greenhouse gas emissions from the transportation sector, by the time a fleet conversion to natural gas would be completed for passenger vehicles, a new conversion to an even lower-carbon fuel will be required. A passenger vehicle fleet conversion to natural gas would be short-lived and yield a low return on investment from a climate perspective.[279]

As in other sectors of the economy, fuel substitution from other fossil fuels to natural gas in some parts of the transportation sector has the potential to yield climate benefits. In addition, it would benefit U.S. national security by decreasing our reliance on a global oil market dominated by outside forces. Although the potential for natural gas use is less in the transportation sector than in others, the potential does exist, primarily for medium- and heavy-duty trucks as well as fleet vehicles and buses.

IX. INFRASTRUCTURE

By Michael Tubman, C2ES

INTRODUCTION

The United States has the world's most extensive infrastructure for transporting natural gas from production and importation sites to consumers all over the country. This transport infrastructure is made up of three main components: gathering pipelines, transmission pipelines, and distribution pipelines.[280] Though fundamentally similar in nature, each type of pipeline is designed for a specific purpose, operating pressure and condition, and length. These components are linked in networks to form the U.S. natural gas infrastructure system (Figure 1).

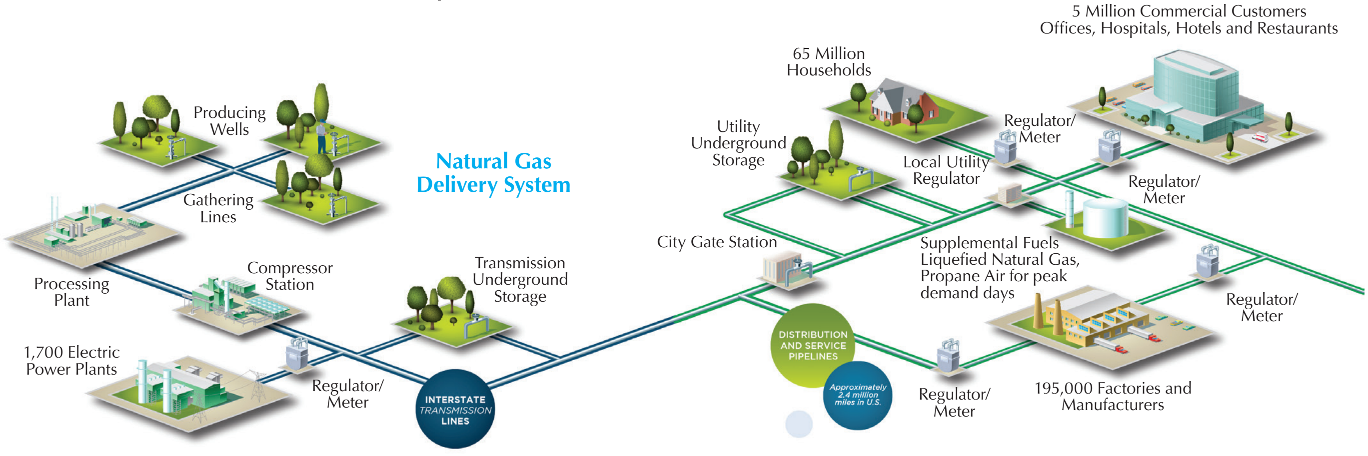
Rising demand for natural gas in the electric power, manufacturing, buildings, and transportation sectors requires significant expansion of the natural gas infrastructure system if these sectors are to reap the potential cost savings and energy security benefits. Increased use of natural gas, when substituted for other fuels, also can significantly reduce greenhouse gas emissions, as long as methane leakage emissions from natural gas systems are minimized. This chapter describes the elements of the U.S. natural gas system and how they function together. Next, it highlights the regional natural gas flows from producing basins to areas of consumption. Then, it discusses the critical issue of methane emissions. Finally, it explores the barriers to infrastructure development and outlines recent innovations in funding models.

ELEMENTS OF THE U.S. NATURAL GAS SYSTEM

Almost all natural gas consumed in the United States is produced in North America, from onshore or offshore wells or, to a much lesser extent, biogas production sites. Natural gas first enters the transport network through gathering pipelines that collect it from the point of production, most commonly the wellhead at the point of extraction, and carry it to processing facilities. Gathering pipelines are usually short and small in diameter and operate at low pressures. In 2011, there were almost 20,000 miles of gathering pipelines in the United States, originating at more than 460,000 wellheads.[281]

Once gathered from well sites, natural gas is processed to remove impurities such as sulfur and carbon dioxide

FIGURE 1: U.S. Natural Gas System



Source: American Gas Association, "About Natural Gas," 2013. Available at: http://www.aga.org/Kc/aboutnaturalgas/Pages/default.aspx

(CO_2) and is dehydrated to remove any water. It is then piped to where there is consumer demand, often hundreds of miles away, through transmission pipelines. Large-diameter (20- to 42-inch), high-pressure transmission pipelines, often called interstate pipelines or trunk lines, efficiently move the gas over vast distances. In 2011, there were 304,087 miles of transmission pipeline in the United States.[282] To ensure pressure in the pipeline and keep the natural gas flowing, compressor stations are placed every 40 to 100 miles. These stations apply pressure to the gas and often filter the gas again to maintain purity. Meters are placed along transmission pipelines to monitor the flow, and valves located at regular intervals can be used to stop flow if needed.[283]

At various points along the gathering and transmission networks, natural gas can be stored temporarily underground in depleted oil or natural gas fields, aquifers, and salt caverns. Storage is used to enhance supply reliability and serves as a physical hedge against the seasonality of natural gas demand. Traditionally, excess supplies of natural gas are stored during the summer and then withdrawn to serve heating demand during the winter or when there are unforeseen supply disruptions. However, as natural gas demand has increased for power generation, including for cooling needs in the summer months, the seasonality of natural gas demand has diminished to some extent. Natural gas can also be stored when purchased at low prices and withdrawn when prices rise, to be sold or consumed. In 2010, there were 400 storage facilities across the United States.[284]

To reach homes and businesses, natural gas leaves the transmission pipeline network and enters the "city gate station," where local distribution companies (local gas utilities) add odorant and lower the pressure before distributing it to residential and commercial customers. Local distribution companies move the gas through a series of larger distribution pipelines, called mains, throughout their service territory, and individual service lines branch off of the mains to reach each consumer. Natural gas regulators, devices in homes and commercial buildings, accept the incoming gas from the highly pressured pipelines and employ a series of valves to lower the pressure of the gas to meet appliance specifications. Distribution pipelines are much smaller pipelines, often only 0.5 to 2 inches in diameter, with pressures at a small fraction of those of the larger transmission pipelines. They may be made of plastic, which is less likely to leak than metal. Distribution networks used by local distribution companies are extensive, having more than 2 million miles of main and individual service pipelines as of 2011.[285]

Together, these components of natural gas infrastructure comprise an important asset that provides access to energy for all sectors of the economy. However, it is a large, dispersed asset that is mostly out of sight. Gathering and transmission pipelines are often in remote locations, while distribution pipelines, though located near the customers they serve, are buried underground. Some pipelines exist within rights-of-way occupied by other users, such as roads or private property, and pipelines often cross local, state, and even national boundaries. These factors make monitoring and regulating pipelines the responsibility of multiple jurisdictions and many levels of government.

Pipelines are regulated by both the federal and state governments. In 2007, 81 percent of natural gas in the United States flowed through transmission pipelines that cross state boundaries. The Federal Energy Regulatory Commission regulates the rates and services of these interstate pipelines as well as the construction of new interstate pipelines. Other pipelines located within states (intrastate pipelines) are regulated by state regulatory commissions. State regulatory commissions regulate both transmission lines and local distribution companies for pipeline siting, construction, operation, and expansion, as well as consumer rate structure.[286]

The federal government also regulates and enforces pipeline safety through the Department of Transportation, which works closely with state governments on pipeline inspection and safety protocols. Corrosion and defects can lead to leaks that have serious safety and environmental implications. Visual inspection of natural gas infrastructure is difficult, and complete replacements are nearly impossible given the vast extent of the network and its location underground. Instead, robotic inspection tools, often called "pigs," can be sent through pipelines to detect leaks, check pipeline conditions, and monitor for weaknesses.[287]

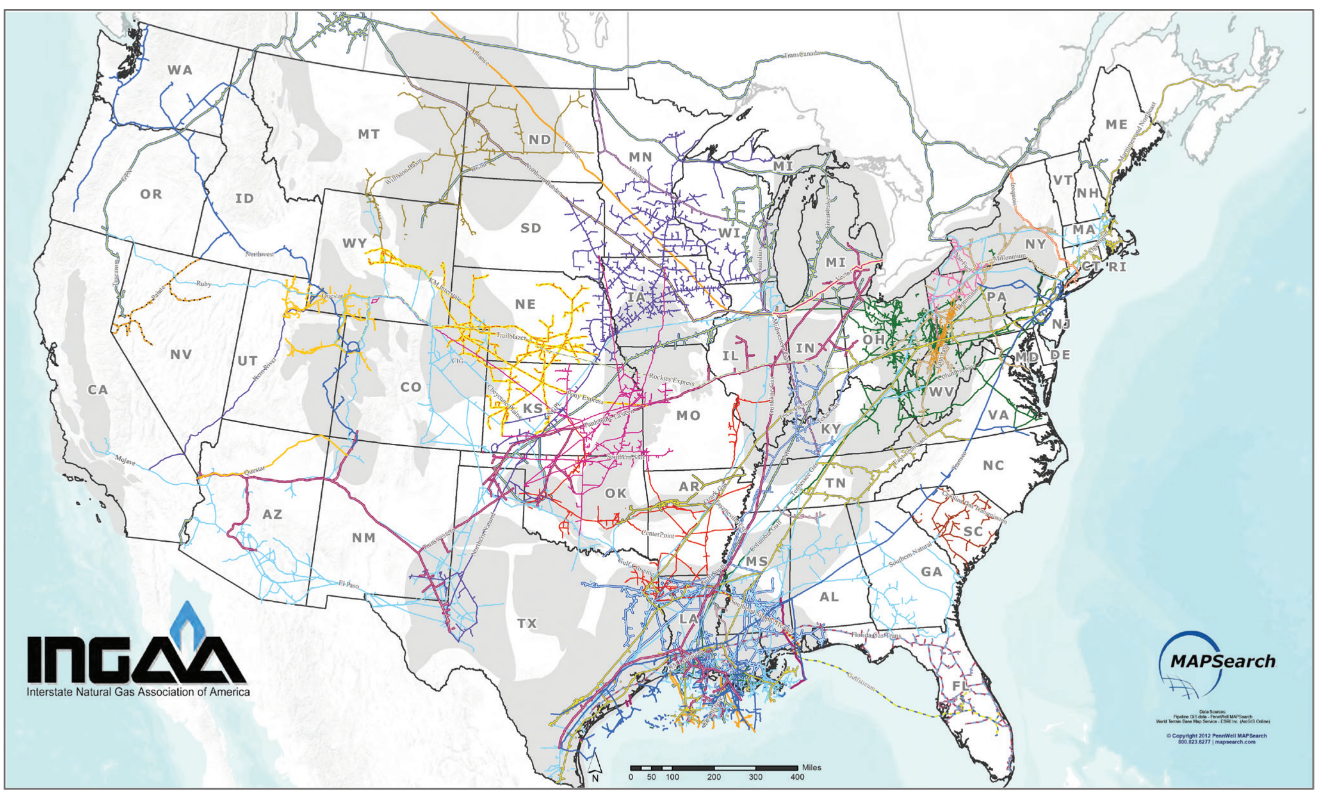
REGIONAL DIFFERENCES IN INFRASTRUCTURE AND EXPANSION

The capacity, extensiveness, and flow direction of existing natural gas infrastructure varies across the country, reflecting historical supply and demand for the fuel as well as disparate state and local policies that enabled infrastructure expansion. Gathering line networks are most extensive from wellheads in traditional gas-producing states such as Texas, Oklahoma, and Louisiana, and most existing intrastate transmission lines take the fuel from those states to manufacturers and consumers in the Midwest and Northeast (Figure 2).

Recent supply increases, lower prices, and increased demand have all led to a need for expanded infrastructure, including gathering, transmission, and distribution pipelines that can bring natural gas to users and may allow natural gas to replace higher-carbon fuel sources and achieve climate benefits. Changes in supply and demand will require that 28,000 to 61,900 miles of new pipelines be constructed in North America by 2030, and $108 to $163 billion worth of investment will be needed. Additional storage capacity of 371 to 598 billion cubic feet (Bcf) will also be needed over the same time period, at a cost of $2 to $5 billion.[288] Current trends in natural gas supply and demand indicate that expansion is likely to fall on the higher ends of these estimates.

Infrastructure needs related specifically to shale gas are growing across the country, reflecting the location of the shale gas resources. Significant investments related to shale gas have been made in states such as Texas and Louisiana that have historically been supply states for conventional gas deposits. Significant additional infrastructure expansion is also needed in parts of the country that have not historically produced natural gas but have been traditional destinations, such as Ohio, Pennsylvania, North Dakota, and West Virginia. Furthermore, new sources of biogas need infrastructure to collect, process, and either transport the gas to existing transmission infrastructure or use it on site. Although the potential of renewable biogas to reduce greenhouse gas emissions is large, further research is needed to ensure that it can be processed properly and safely added to the existing system, which was built specifically to withstand the constituents of geologically formed natural gas.[289] In sum, several of the new supply sources require new infrastructure, and in other cases, existing infrastructure may be repurposed and deployed to bring new sources to market. As more new sources are

FIGURE 2: Interstate Pipelines, 2013



Source: Interstate Natural Gas Association of America and PennWell tapped, the existing transmission pipeline infrastructure must continue to be creatively deployed and expanded to serve regional market needs.

Similarly, local distribution networks will need to be expanded, with new demand for natural gas appliances, industrial uses, distributed generation, and vehicle fueling in homes and businesses. Investments are necessary in new mains, service lines, meters, and regulators that can service new customers. Indirect investments will also be required to enhance the capacity of the overall system, including for control rooms, main reinforcements, and improved flow design.[290]

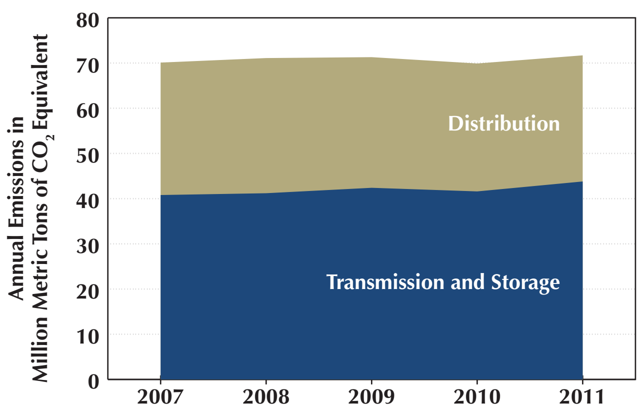
DIRECT EMISSIONS FROM NATURAL GAS INFRASTRUCTURE

In 2011, methane emissions from transmission pipelines and storage totaled 44 million metric tons of CO_2 equivalent (CO_2e), while emissions from distribution networks totaled 27 million metric tons CO_2e.[291] These figures have been fairly consistent over time as network expansion has been offset by better system management (including leak detection), more energy-efficient technology, and the replacement of equipment with new materials that are less subject to leakage, including replacing cast iron and steel pipe with plastics.[292, 293] While methane emissions from natural gas infrastructure are a very small portion of the nation's total greenhouse gas emissions (Figure 3 and Figure 4), methane is a potent greenhouse gas, as described in chapter 3. Given methane's potency, it is critical to reduce leakage to ensure that its climate benefits are maximized when compared with other fossil fuels that it may replace.[294]

Leaked Methane

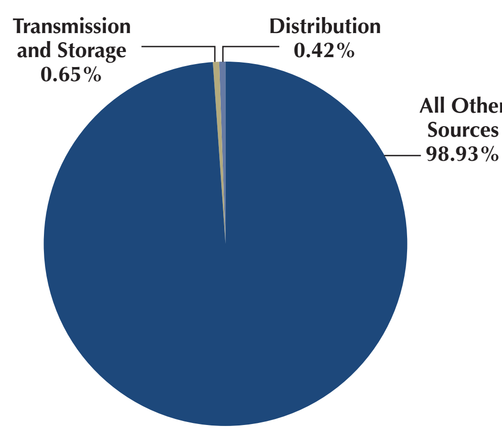
Throughout the transportation of the fuel from gathering at the well to distribution to end-use consumers, there is potential for methane to leak into the atmosphere. Potential leakage points include production wells, valves, compressor stations, faulty seals, pressure regulators, and even broken pipes. Because methane leakage and accumulation can be an important safety issue, natural gas operators have robust safety programs in compliance with federal and state pipeline safety requirements to detect and repair leaks that pose safety risks. Methane emissions that do not pose safety concerns nevertheless can have significant implications for the climate and for the relative benefits of substituting natural gas for other fuel sources. At natural gas storage facilities, methane emissions may leak from compressors and dehydrators. At the local distribution level, methane emission leakage can occur at city gate station valves, seals, and pressure regulators, or from the joints of cast iron or unprotected steel pipe.[295] The majority of all greenhouse gas emissions from natural gas infrastructure are due to leaked emissions.[296]

FIGURE 3: Historical Emissions from Transmission, Storage and Distribution, 2007 to 2011



Source: Environmental Protection Agency, "U.S. Greenhouse Gas Inventory Report," 2013. Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2011-Chapter-3-Energy.pdf

FIGURE 4: Emissions from Natural Gas Infrastructure as a Percentage of Total U.S. Greenhouse Gas Emissions, 2011



Source: Environmental Protection Agency, "U.S. Greenhouse Gas Inventory Report," 2013. Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2011-Chapter-3-Energy.pdf

Venting and Flaring

In addition to leaked emissions, methane can be intentionally released or vented as part of the production process at the wellhead or to reduce pipeline pressure. For safety and environmental reasons, however, intentionally-released methane is often burned off in a process called flaring. Flaring combusts the methane on site, forming CO_2, a less potent, though very significant, greenhouse gas.[297] (The climate implications of CO_2 and methane are compared in chapter 3.) Flaring of methane most often occurs when natural gas is found as a byproduct or co-product of other fossil fuel production and insufficient gathering pipeline infrastructure or market incentives exist to take the natural gas to market. In 2012 in Texas, where gathering pipeline networks are well developed, less than 1 percent of the natural gas produced was flared.[298] In North Dakota, where oil production from the Bakken Shale formation is a much newer phenomenon, almost 32 percent of the associated natural gas is flared, primarily because of a lack of gathering infrastructure.[299] With relatively low natural gas prices, there is less economic incentive for companies to build gathering infrastructure and monetize the resource.

In August 2012, a new federal requirement to minimize venting and flaring was established as part of the Environmental Protection Agency's New Source Performance Standards for oil and gas wells. The new regulations require that all new natural gas wells flare rather than vent, and as of 2015 use "green completion" technology that will allow excess natural gas from the well completion process to be taken to market. Many natural gas producers already use such technology.300 However, for the "green completion" rule to apply to the gathering of natural gas from the Bakken Shale or other primarily oil production sites, it would have to be expanded from its present form (see the discussion of "green completion" rules in chapter 3).

Reducing Emissions from Infrastructure

Many technologies and process improvements can reduce methane emissions from natural gas infrastructure. The federal Natural Gas STAR program, for example, has worked with industry to identify technical and engineering solutions to vented, leaked, and combustion-related emissions, including zero-bleed pneumatic controllers, improved valves, corrosion-resistant coatings, and dry-seal compressors, as well as improved leak detection and repair strategies. The solutions identified by this voluntary program often have payback periods of less than three years, depending on the price of natural gas. Participants in Natural Gas STAR reported that methane emissions from infrastructure were reduced by 15.9 Bcf in 2010, and overall, a total of 276.5 Bcf of greenhouse gases have been avoided since the program began in 1993.[301] Local distribution companies have reduced emissions from their low-pressure networks by continuing to replace cast iron and steel pipes with inexpensive and durable plastic pipes; however, this plastic is not strong enough to be used in high-pressure transmission lines.[302]

BARRIERS TO INFRASTRUCTURE DEVELOPMENT

As other chapters in this report explain, natural gas may be used to reduce greenhouse gas emissions in multiple sectors of the economy, including electric power, manufacturing, buildings, and transportation. While new pipelines are being built every day, there is a dramatic need for new pipeline investment to move new sources of natural gas supply to new regions and new users. Distribution pipeline networks, in particular, are challenged by financial and other barriers to expansion and improvement.

Funding Distribution Pipeline Expansion

For local distribution networks, the cost of expansion varies considerably depending on whether the network is being expanded to new or existing communities, the density of the neighborhood, and the terrain. For new distribution pipelines in urban areas, challenges include costly repairs of overlaying roads and landscaping, negotiations with entities holding surface and other subsurface rights-of-way, and public inconveniences. Accordingly, new urban pipelines can cost five times as much as rural ones.[303] Costs can be lowered when buildings are designed and constructed to be ready for natural gas access; retrofitting existing buildings with internal piping and hook-ups to natural gas supplies is more expensive.

Funding local distribution networks can be challenging and is typically dealt with through a formal regulatory proceeding called a rate case where public utility commissions determine allowable utility rates based on factors including utility operation costs, depreciation, investment, and consumer needs. Traditionally, expansion costs are considered during the rate case proceedings, but costs can only be recovered after investments are made. This time lag discourages or prevents utilities from investing in infrastructure. State-level regulatory innovations have provided some policy options to overcome these investment challenges. Some states, such as Nevada, allow the use of a deferred accounting mechanism so that costs can be better aligned temporally with ratemaking cases before state regulatory commissions. Seven southern states, including Texas, have decoupled gas consumption and cost recovery to create what is known as a "rate stabilization method." This method allows rates to adjust annually for infrastructure replacement and construction rather than simply the amount of natural gas throughput.[304]

Funding models that can foster greater access to natural gas are being explored throughout the country. For example, in North Carolina, rules established by the public utilities commission allow for dedicated funds for new distribution pipelines. A local distribution company may petition the public utilities commission to establish a Natural Gas Expansion Fund to help pay for the otherwise economically infeasible expansion of distribution pipelines. Additional money may be added to the Natural Gas Expansion Fund, including refunds from natural gas suppliers to the local distribution company, expansion surcharges, and other resources, and then, with approval by the public utilities commission, the company may pay for the specified distribution pipeline construction projects.[305] In 2011, the Vermont Public Service Board approved a plan by Vermont Gas Systems to use $17.6 million previously planned for ratepayer refunds to instead support expansion of its distribution network over four years, although these funds will cover only part of the needed finance.[306] This plan transferred some of the costs of expansion onto existing customers and offered the reduction of statewide greenhouse gas emissions as one rationale.[307] A 2012 law passed by the Maine Legislature authorizes the Finance Authority of Maine to issue up to $275 million in loans and $55 million in bonds for natural gas distribution system expansions. The funds will be available only if the applicant contributes at least 25 percent of the expected cost of the project.[308] Municipal utilities can also offer innovative solutions. For example, the municipal natural gas utility in Sunrise, Florida, will install main and service lines to neighborhoods at no cost as long as 25 percent of residents commit to installing a natural gas space or water heater, range, or clothes dryer within six months. Natural gas piping within the homes must be paid for by residents.[309]

Funding Upgrades and Replacements

Other innovative policy mechanisms are being developed to pay to upgrade and replace existing pipelines. Some states, such as Colorado, authorize tracker mechanisms allowing rates to change in response to the utility's operating costs and conditions outside of a complex rate case proceeding, specifically in response to federal and state safety requirements. A similar process outside the rate case in states such as Kentucky permits temporary surcharges for partial program cost recovery. The Georgia Public Services Commission has permitted Atlanta Gas Light Company to institute a surcharge on customer bills throughout its service territory to help fund pipeline replacement, improvement, and pressure increases through the Georgia Strategic Infrastructure Development and Enhancement (STRIDE) Program. The Georgia Public Services Commission reviews the surcharge and related plans every three years, thereby eliminating the need for rate cases and associated regulatory lag. Also, from 2009 to 2012, a pilot program called the Customer Growth Program was paid for through the STRIDE surcharge. It helped fund new pipeline construction and extensions, including strategic development corridors to regions far removed from existing Atlanta Gas Light Company infrastructure. It also helped overcome the barrier of high upfront costs for new natural gas pipelines.[310] However, the STRIDE program has not been renewed. The Atlanta Gas Light Company Universal Service Fund can also be used to pay for distribution pipeline expansion, and its monies may contribute up to 5 percent of Atlanta Gas Light Company's capital budget during a fiscal year.

Other Challenges

Beyond questions of funding, pipelines are affected by a number of project-specific requirements and regulations at the federal, state, and local levels. These requirements pertain to route selection, siting, and project approval by regulatory agencies that may all be affected by environmental, safety, community, operation, construction timing, and cost concerns. The size of the challenge for any individual project will vary significantly depending on the pipeline and the jurisdictions it crosses.[311] For natural gas to realize its climate benefits, infrastructure projects must meet these requirements, allowing the system to expand for greater low-emission use across the economy.

CONCLUSION

Natural gas is transported from areas of production to final consumers through networks of gathering pipelines, transmission pipelines, and distribution pipelines. These extensive networks are necessary to provide opportunities for low-emission end uses of natural gas. Given the recent surge in natural gas supply, the new source regions, and new uses, infrastructure must rapidly adapt. Gathering pipelines must be brought to more points of production, including areas where associated gas can be captured for use. Transmission pipelines must be expanded to ensure adequate supply can reach new regions of the country. Distribution pipeline networks must be built out to serve more manufacturing facilities, homes, and businesses. Increased policy support and innovative funding, particularly for distribution pipelines, are needed to support the rapid deployment of this infrastructure.

X. CONCLUSIONS AND RECOMMENDATIONS

Natural gas plays a role in all sectors of the U.S. economy, constituting 27 percent of total U.S. energy use in 2012. Its prominence is expected to grow as the supply boom unleashed by new drilling technologies continues in coming decades. Expectations of sustained abundance and correspondingly low and relatively stable natural gas prices are sparking widespread interest in additional ways that this domestic energy resource can replace oil and coal as the major fuel undergirding a growing economy. Indeed, natural gas is projected to displace petroleum as the dominant fuel used in the United States within a few decades.

In these early days of this energy transition, it is imperative to set a course for using this increasingly abundant domestic resource in ways that help meet, rather than aggravate, the challenge of climate change. This report examines ways that natural gas can be leveraged to reduce greenhouse gas emissions across a growing economy and reaches three crosscutting conclusions.

First, substitution of natural gas for other fossil fuels can contribute to U.S. efforts to reduce greenhouse gas emissions in the near to mid-term, even as the economy grows. At the beginning of 2013, energy sector emissions are at the lowest levels since 1994, in part because of the substitution of natural gas for coal in the power sector. Substitution of natural gas for coal, petroleum, and grid-supplied electricity is underway in other parts of the economy and will bring similar benefits to the climate and air quality. In the buildings sector, for example, a large reduction in emissions is possible through greater direct use of natural gas in an array of more efficient appliances and expanded use of CHP. The manufacturing sector also has a significant opportunity to reduce emissions even as it expands. Manufacturers can increase their consumption of natural gas as feedstock and an energy source, while reducing the emissions intensity of production. Finally, in the transportation sector, natural gas fuel substitution can reduce greenhouse gas emissions when used in fleets and heavy-duty vehicles.

Second, in the long term, the United States cannot achieve the reduction in greenhouse gas emissions necessary to address the serious challenge of climate change by relying on fuel substitution to natural gas alone. Low-carbon investment must be dramatically expanded. Zero-emission sources of energy such as wind, nuclear, and solar are critical, as are the use of carbon capture and storage technologies at fossil fuel plants and continued improvements in energy efficiency. Given that many renewable energy sources are intermittent, natural gas can serve as a complementary and reliable backup. In addition, because fossil fuels will likely be part of the energy fuel mix for the foreseeable future, carbon capture and storage will need to be deployed. Without a price on carbon emissions, alternative policy support will be needed to ensure optimal investment in zero-carbon energy sources and technologies.

Third, direct releases of methane into the atmosphere must be minimized. The primary component of natural gas is methane, which is a very potent greenhouse gas. Total methane emissions from natural gas systems in the United States have improved during the last two decades, declining 13 percent from 1990 to 2011. Nevertheless, given its impact on the climate, especially in the short term, it is important to better understand and more accurately measure the greenhouse gas emissions from natural gas production and use in order to achieve emissions reductions along the entire natural gas value chain.

The basis for these cross-cutting conclusions is a detailed examination of the current and potential role of natural gas in major sectors of the economy. Sector-specific conclusions and recommendations include:

Expanded use of natural gas has improved fuel diversity in the power sector. From 2003 to 2012, the share of primary energy consumption from coal for electricity generation dropped from 53 percent to 37 percent, while the share fulfilled by natural gas grew from 14 percent to 29 percent. Accordingly, the fuel mix in electricity generation has become more diverse in recent years. However, concern exists that some regions may become too dependent upon natural gas in the long term, especially as market pressures affect nuclear and renewable energy generation. Too much reliance on any one fuel can expose utilities, ratepayers, and the economy to the risks associated with commodity price volatility. Furthermore, natural gas-fired generation should not displace investment in zero-carbon generation, carbon capture and storage, and energy efficiency measures. If this occurs, the United States will not be able to meet its long-term goals for reducing greenhouse gas emissions.

Natural gas can be complementary with renewable energy. Instead of being thought of as competitors, natural gas and renewable energy sources such as wind and solar can be complementary components of the power sector. Natural gas plants have the ability to quickly scale up or down their electricity production and so can act as an effective hedge against the intermittency of renewables. The fixed fuel price (at zero) of renewables can likewise act as a hedge against potential natural gas price volatility. Low natural gas prices can also help facilitate an increase in renewable energy in some regions. In order for this mutually beneficial relationship to flourish, carefully designed policy that allows the addition of both sources to the grid in a complementary fashion must come into play and be encouraged by public utility commissions. Natural gas plants expansion should be leveraged to enable the expansion of renewable generation.

Natural gas can increase the overall efficiency of buildings through use of equipment with higher full-fuel-cycle efficiency. Thermal applications of natural gas in buildings have a lower greenhouse gas emission footprint compared with other fossil energy sources. Natural gas for thermal applications is more efficient than grid-delivered electricity, yielding less energy losses along the supply chain and therefore fewer greenhouse gas emissions. Information and incentives should be modified to inform consumers of the environmental benefits of natural gas use and to encourage its increased use when it has the potential to reduce greenhouse gas emissions—particularly its direct use in buildings and manufacturing settings. At present, labeling, building codes, and economic incentives are not aligned to maximize the use of natural gas in low-emitting ways.

Aligning incentives is particularly important in the building sector, as consumers and developers seeking to minimize up-front cost often do not realize that operating costs and environmental costs may be much higher for electric appliances. In addition, although current energy efficiency programs aim to reduce greenhouse gas emissions from appliances and buildings in two important ways—by setting standards and efficiency labeling programs—these standards are based solely on site efficiency, which is reflected in the energy and cost savings identified on efficiency labels. But efficiency labels based only on site efficiency do little to educate consumers about the total energy needed to power appliances and the greenhouse gases associated with that energy and, as such, often steer consumers toward electric appliances even if a natural gas appliance may be more efficient overall and produce fewer greenhouse gas emissions. It is important, therefore, that the source-to-site efficiency of an appliance also be taken into consideration, and in regions with fossil fuel-dominated grid electricity, natural gas appliances should be encouraged.

The efficient use of natural gas in the manufacturing sector needs to be encouraged. Replacing old coal-fired boilers with more efficient natural gas boilers can yield significant emissions benefits. CHP systems should also be deployed to make use of waste heat and avoid transmission losses. The incentives for CHP are often not properly aligned. Specifically, while CHP has significant environmental benefits, it can significantly decrease the demand for grid-supplied electricity, which can impact the rate base remaining on the grid. Policies are needed to overcome this and other barriers to expanded CHP deployment. States are in an excellent position to take an active role in promoting CHP during required industrial boiler upgrades and new standards for cleaner electricity generation in coming years.

Distributed generation technologies can offer options for using natural gas and reducing emissions. Distributed generation technologies, such as microgrids, microturbines, and fuel cells, can be used in configurations that reduce greenhouse gas emissions when compared with the centralized power system because they can reduce transmission losses and use waste heat onsite. Distributed generation has many other advantages over centralized electricity generation, including end-users' access to waste heat, easier integration of renewable energy, heightened reliability of the electricity system, reduced peaking power requirements, and less vulnerability to terrorism due to more geographically dispersed, smaller power plants. To realize the potential of these technologies and overcome high upfront equipment and installation costs, policies like financial incentives and tax credits need to be more widespread, along with consumer education about their availability.

Fuel substitution in fleets and heavy-duty vehicles offers the greatest opportunity to reduce greenhouse gas emissions in the transportation sector. Passenger vehicles, in contrast, likely represent a much smaller emission reduction opportunity even though natural gas emits fewer greenhouse gases than gasoline or diesel when combusted. The reasons for this include the smaller emission reduction benefit (compared to coal conversions), and the time it will take for a public infrastructure transition. By the time a passenger fleet conversion to natural gas could be completed, a new conversion to an even lower-carbon system, like fuel cells or electric vehicles, will be required to ensure significant emissions reductions throughout the economy.

Natural gas infrastructure expansion is needed to ensure access for low-emitting uses. New domestic supplies of natural gas require significant investment in infrastructure. Additional gathering and transmission pipeline capacity is needed in parts of the country that have not historically produced natural gas but have been traditional destinations, such as Ohio, Pennsylvania, North Dakota, and West Virginia. Expanded distribution pipeline networks are needed to serve greater numbers of commercial, industrial, and residential natural gas customers throughout the U.S. Moreover, expanding natural gas delivery systems within homes and businesses that have existing access will be necessary to support a greater number of end-use applications, such as natural gas-fueled space and water heating. Innovative funding models and support are needed to make the expansion and upgrading of natural gas infrastructure economically feasible for customers and utilities.

In the coming years, abundant natural gas will play an increasingly prominent role across all sectors of the U.S. economy. Increased availability of natural gas can yield economic opportunities and lower greenhouse gas emissions. Yet, natural gas is not carbon-free. A future with expanded natural gas use will require diligence to ensure that potential benefits to the climate are achieved.

ENDNOTES

1 Primary energy sources include petroleum, natural gas, coal, renewable energy, and nuclear power.

2 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011, page 17. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

3 Unconventional resource accumulations tend to be distributed over a larger area than conventional resources, require greater pressure for extraction (have "low permeability"), and they usually require advanced technologies and techniques such as horizontal wells or artificial stimulation in order to be economically productive.

4 Energy Information Administration, "Annual Energy Outlook 2013 Early Release," December 2012. Available at http://www.eia.gov/forecasts/aeo/er/index.cfm.

5 In economic terms, the supply of natural gas is often referred to as reserves and is classified with two primary categories, proven and unproven. Proven reserves are those that are economically recoverable from known resources using currently available technology. Unproven reserves are those considered not economically or technically recoverable or somehow not producible for regulatory reasons.

6 National Petroleum Council, "Balancing Natural Gas Policy–Fueling the Demands of a Growing Economy," National Petroleum Council, September, 2003. Available at Balancing Natural Gas Policy–Fueling the Demands of a Growing Economy.

7 Energy Information Administration, "Annual Energy Outlook 2012: Early Release Overview," Report Number DOE/EIA-0383ER(2012), January 23, 2012, page 9. Available at http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf.

Note: EIA's estimated technically recoverable resource of U.S. shale gas was reduced from 827 Tcf in 2010 to 482 Tcf in 2011. The decline mostly reflects changes in the assessment for the Marcellus shale, from 410 Tcf to 141 Tcf, based on better data provided from the rapid growth in drilling in the Marcellus over the past two years.

8 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

9 Energy Information Administration, "AEO2013 Early Release," December 2012. Available at http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf.

10 Energy Information Administration, "Total Energy: Natural Gas Consumption by Sector, 1949–2011," September 2012. Available at http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0605.

11 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011, page 7. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

12 ICF International for the Ontario Energy Board, "2010 Natural Gas Market Review," August 2010, page 50. Available at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0199/ICF_Market_Report_20100820.pdf.

13 The White House, "The Blueprint for a Secure Energy Future: Progress Report," March 2012, page 2. Available at http://www.whitehouse.gov/sites/default/files/email-files/the_blueprint_for_a_secure_energy_future_oneyear_progress_report.pdf.

14 Energy Information Administration, "Annual Energy Outlook 2011: Reference Case," December 2012. Available at http://www.eia.gov/forecasts/aeo/er/executive_summary.cfm.

15 C2ES, "Fact Sheet: Natural Gas," accessed April 2013. Available at http://www.c2es.org/technology/factsheet/natural-gas#7.

16 Energy Information Administration, "Annual Energy Outlook 2011," April 26, 2011, Report Number DOE/EIA-0383(2011), page 2. Available at http://www.eia.gov/forecasts/aeo/pdf/0383%282011%29.pdf.

17 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

Note: In addition to the Barnett, since 2005 producers have begun intensively developing plays in the Woodford, north of the Barnett in Texas and Oklahoma; the Fayetteville in Arkansas; and the Haynesville in Louisiana/East Texas. During this time, development also began in the Marcellus Shale of the eastern United States.

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This report provides an overview of natural gas production, the climate implications of expanded natural gas use, potential uses and benefits in key sectors, and related infrastructure issues.

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PERSPECTIVE

A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas

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Abstract

In April 2011, we published the first peer-reviewed analysis of the greenhouse gas footprint (GHG) of shale gas, concluding that the climate impact of shale gas may be worse than that of other fossil fuels such as coal and oil because of methane emissions. We noted the poor quality of publicly available data to support our analysis and called for further research. Our paper spurred a large increase in research and analysis, including several new studies that have better measured methane emissions from natural gas systems. Here, I review this new research in the context of our 2011 paper and the fifth assessment from the Intergovernmental Panel on Climate Change released in 2013. The best data available now indicate that our estimates of methane emission from both shale gas and conventional natural gas were relatively robust. Using these new, best available data and a 20-year time period for comparing the warming potential of methane to carbon dioxide, the conclusion stands that both shale gas and conventional natural gas have a larger GHG than do coal or oil, for any possible use of natural gas and particularly for the primary uses of residential and commercial heating. The 20-year time period is appropriate because of the urgent need to reduce methane emissions over the coming 15–35 years.

Introduction

Natural gas is often promoted as a bridge fuel that will allow society to continue to use fossil energy over the coming decades while emitting fewer greenhouse gases than from using other fossil fuels such as coal and oil. While it is true that less carbon dioxide is emitted per unit energy released when burning natural gas compared to coal or oil, natural gas is composed largely of methane, which itself is an extremely potent greenhouse gas. Methane is far more effective at trapping heat in the atmosphere than is carbon dioxide, and so even small rates of methane emission can have a large influence on the greenhouse gas footprints (GHGs) of natural gas use.

Increasingly in the United States, conventional sources of natural gas are being depleted, and shale gas (natural gas obtained from shale formations using high-volume hydraulic fracturing and precision horizontal drilling) is rapidly growing in importance: shale gas contributed only 3% of United States natural gas production in 2005, rising to 35% by 2012 and predicted to grow to almost 50% by 2035 [1]. The gas held in tight sandstone formations is another form of unconventional gas, also increasingly obtained through high-volume hydraulic fracturing and is growing in importance. In 2012, gas extracted from shale and tight-sands combined made up 60% of total natural gas production, and this is predicted to increase to 70% by 2035 [1]. To date, shale gas has been almost entirely a North American phenomenon, and largely a U.S. one, but many expect shale gas to grow in global importance as well.

In 2009, I and two colleagues at Cornell University, Renee Santoro and Tony Ingraffea, took on as a research challenge the determination of the GHG of unconventional gas, particularly shale gas, including emissions of methane. At that time, there were no papers in the peer-reviewed literature on this topic, and there were relatively few papers even on the contribution of methane to the GHG of conventional natural gas [2–4]. At the end of 2009, the U.S. Environmental Protection Agency (EPA) still did not distinguish between conventional gas and shale gas, and they estimated methane emissions for the natural gas industry using emission factors from a 1996 study conducted jointly with the industry [5]; shale gas is not mentioned in that report, which is not surprising since significant shale gas production only started in the first decade of the 2000s.

We began giving public lectures on our analysis in March 2010, and these attracted media attention. One of our points was that it seemed likely that complete life cycle methane emissions from shale gas (from well development and hydraulic fracturing through delivery of gas to consumers) were greater than from conventional natural gas. Another preliminary conclusion was that the EPA methane emission estimates (as they were reported in 2009 and before, based on [5]) seemed at least two- to three-fold too low. In response to public attention from our lectures, the EPA began to reanalyze their methane emissions [6], and in late 2010, EPA began to release updated and far higher estimates of methane emissions from the natural gas production segment [7]. In April 2011, we published our first paper on the role of methane in the GHG of shale gas [8]. We concluded that (1) the amount and quality of available data on methane emissions from the natural gas industry were poor; (2) methane emissions from shale gas were likely 50% greater than from conventional natural gas; and (3) these methane emissions contributed significantly to a large GHG for both shale gas and conventional gas, particularly when analyzed over the timescale of 20-years following emission. At this shorter timescale – which is highly relevant to the concept of natural gas as a bridge or transitional fuel over the next two to three decades – shale gas appeared to have the largest greenhouse warming consequences of any fossil fuel (Fig. 1). Because our conclusion ran counter to U.S. national energy policy and had large implications for climate change, and because the underlying data were limited and of poor quality, we stressed the urgent need for better data on methane emissions from natural gas systems. This need has since been amplified by the Inspector General of the EPA [9].

Our paper received immense media coverage, as evidenced by Time Magazine naming two of the authors

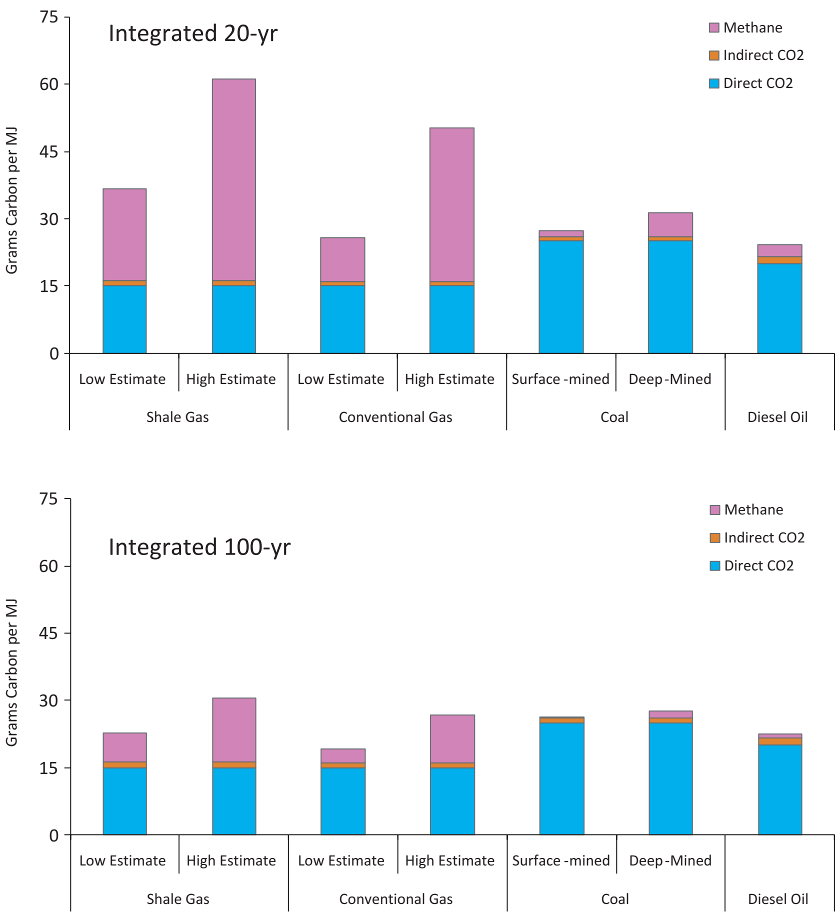

Figure 1. Comparison of the greenhouse gas footprint of shale gas, conventional natural gas, coal, and oil to generate a given quantity of heat. Two timescales for analyzing the relative warming of methane and carbon dioxide are considered: an integrated 20-year period (top) and an integrated 100-year period (bottom). For both shale gas and conventional natural gas, estimates are shown for the low- and high-end methane emission estimates from Howarth et al. [8]. For coal, estimates are given for surface-mined and deep-mined coal, since methane emissions are greater for deeper mines. Blue bars show the direct emissions of carbon dioxide during combustion of the fuels; the small red bars show the indirect carbon dioxide emissions associated with developing and using the fuels; and the magenta bars show methane emissions converted to g C of carbon dioxide equivalents using period-appropriate global warming potentials. Adapted from [8].

(Howarth and Ingraffea) “People who Mattered” to the global news in the December 2011 Person of the Year Issue [10]. The nine months after our paper was published saw a flurry of other papers on the same topic, a huge increase in the rate of publication on the topic of methane and natural gas compared to prior years and decades. While some of these offered support for our analysis, most did not and were either directly critical of our work, or without referring to our analysis reached conclusions more favorable to shale gas as a bridge fuel. Few of these papers published in the 9 months after our April 2011 paper provided new data; many simply offered different interpretations of previously presented information (as is reviewed briefly below). However, in 2012 and 2013 many new studies were published with major new insights and sources of data. In this paper, I briefly review the work on methane and natural gas published between April 2011 and February 2014, concentrating on those studies that have produced new primary data.

There are four components that are central to evaluating the role of methane in the GHG footprint of natural gas: (1) the amount of carbon dioxide that is directly emitted as the fuel is burned and indirectly emitted to obtain and use the fuel; (2) the rate of methane emission from the natural gas system (often expressed as a fraction of the lifetime production of the gas well, normalized to the amount of methane in the gas produced); (3) the global warming potential (GWP) of methane, which is the relative effect of methane compared to carbon dioxide in terms of its warming of the global climate system and is a function of the time frame considered after the emission of the methane; and (4) the efficiency of use of natural gas in the energy system. The GHG is then determined as:

$$\text{GHG footprint} = [\text{CO}_2\text{emissions} + (\text{GWP} \times \text{methane emissions})]/\text{efficiency}$$

There is widespread consensus on the magnitude of the direct emissions of carbon dioxide, and the indirect emissions of carbon dioxide used to obtain and use natural gas (for example, in building and maintaining pipelines, drilling and hydraulically fracturing wells, and compressing gas), while uncertain, are also relatively small [8]. In this paper, I separately consider each of the other three factors (methane emissions, GWP, and efficiency of use) in the context of our April 2011 paper [8] and the subsequent literature.

How Much Methane is Emitted by Natural Gas Systems?

We used a full life cycle analysis in our April 2011 paper, estimating the amount of methane emitted to the atmosphere as a percentage of the lifetime production of a gas well (normalized to the methane content of the natural gas), including venting and leakages at the well site but also during storage, processing, and delivery to customers. For conventional natural gas, we estimated a range of methane emissions from 1.7% to 6% (mean = 3.8%), and for shale gas a range of 3.6% to 7.9% (mean = 5.8%) [8]. We attributed the larger emissions from shale gas to venting of methane at the time that wells are completed, during the flowback period after high-volume hydraulic fracturing, consistent with the findings of the EPA 2010 report [7]. We assumed all other emissions were the same for conventional and shale gas. We estimated that downstream emissions (emissions during storage, long-distance transport of gas in high-pressure pipelines, and distribution to local customers) were 1.4–3.6% (mean = 2.5%) of the lifetime production of a well, and that the upstream emissions (at the well site and for gas processing) were in the range of 0.3–2.4% (mean = 1.4%) for conventional gas and 2.2–4.3% (mean = 3.3%) for shale gas (Table 1).

Table 1. Full life cycle-based methane emission estimates, expressed as a percentage of total methane produced in natural gas systems, separated by upstream emissions for conventional gas, upstream emissions for unconventional gas including shale gas, and downstream emissions for all natural gas. Studies are listed chronologically, and our April 2011 study is boldfaced.

	Upstream conventional gas	Upstream unconventional gas	Downstream
EPA 1996 [5]	0.2%	–	0.9%
Hayhoe et al. [2]	1.4	–	2.5
Jamarillo et al. [4]	0.2	–	0.9
Howarth et al. [8]	**1.4**	**3.3**	**2.5**
EPA [11]	1.6	3.0	0.9
Ventakesh et al. [12]	1.8	–	0.4
Jiang et al. [13]	–	2.0	0.4
Stephenson et al. [14]	0.4	0.6	0.07
Hultman et al. [15]	1.3	2.8	0.9
Burnham et al. [16]	2.0	1.3	0.6
Cathles et al. [17]	0.9	0.9	0.7

Total emissions are the sum of the upstream and downstream emissions. Studies are listed chronologically by time of publication. Dashes indicate no values provided. The full derivation of the estimates shown here is provided elsewhere [18, 19].

Although there were no prior papers on methane emissions from shale gas when our paper was published, we can compare our estimates for conventional natural gas with earlier literature (Table 1). Our mean estimates for both upstream and downstream emissions were identical to the "best estimate" of Hayhoe et al. [2], although that paper presented a wider range of estimates for both upstream and downstream. It is important to note that we used several newer sources of information not available to Hayhoe et al. [2], making the agreement all the more remarkable. The Howarth et al. [8] estimates were substantially higher than the emission factors used by the EPA through 2009 based on the 1996 joint EPA-industry study [5], which were only 1.1% for total emissions, 0.2% for upstream emissions, and 0.9% for downstream emissions. In the only other peer-reviewed paper on life cycle methane emissions from conventional gas published in the decade or two before our paper, Jamarillo et al. [4] relied on these same EPA emission factors, although new data on downstream emissions had already shown these emission factors to be too low [3].

Through late 2010 and the first half of 2011, the EPA provided a series of updates on their methane emission factors from the natural gas industry, giving estimates for shale gas for the first time as well as substantially increasing their estimates for conventional natural gas. These are discussed in detail by us elsewhere [18, 19]. Note that the EPA did not and still has not updated their estimates for downstream emissions, still using a value of 0.9% from a 1996 study [5]. For upstream emissions, the revised EPA estimates gave emission factors of 1.6% (an increase from their earlier value of 0.2%) for conventional natural gas and 3.0% for shale gas [18, 19]. Note that the EPA estimates for upstream emissions presented in 2011 [11] were 14% higher than ours for conventional gas and 10% lower than ours for shale gas. Total emissions were more divergent, due to the large difference in downstream emission estimates (Table 1).

In addition to the revised EPA emission factors, many other papers presented life cycle assessments of methane emissions from shale gas, conventional gas, or both in the immediate 9 months after April 2011 (Table 1). We and others have critiqued these publications in detail elsewhere [18–20]. Here, I will emphasize four crucial points:

1 For the upstream emissions in Table 1, all studies relied on the same type of poorly documented and highly uncertain information. These poor-quality data led us in Howarth et al. [8] to call for better measurements on methane fluxes, conducted by independent scientists. Several such studies have been published in the past 2 years, as is discussed further below, and these provide a more robust approach for estimating methane emissions.

2 At least some of the differences among values in Table 1 are due more to different assumptions about the lifetime production of a shale gas well than to differences in emissions per well [18, 20]. Note that the upstream life cycle emissions are scaled to the lifetime production of a well (normalized to the methane content of the gas produced for the estimates given in Table 1), and this was very uncertain in 2011 since shale gas development is such a new phenomenon [21]. A subsequent detailed analysis by the U.S. Geological Survey has demonstrated that the mean lifetime production of unconventional gas wells is in fact lower than any of papers in Table 1 assumed [22], meaning that upstream shale gas emissions per production of the well from all of the studies should be higher, in some cases substantially so [18, 20].

3 The downstream emissions in Table 1 are particularly uncertain, as highlighted by both Hayhoe et al. [2] and Howarth et al. [8]. Note that all of the other papers listed in Table 1 base their downstream emissions on the EPA emission factors from 1996 [5], and none are higher than those EPA estimates, even though a 2005 paper in *Nature* demonstrated higher levels of emission from long-distance pipelines in Europe [3]. Several of the papers in Table 1 have downstream emissions that are lower than the 1996 EPA values, as they are focused on electric power plants and assume that these plants are drawing on gas lines that have lower emissions than the average, which would include highly leaky low-pressure urban distribution lines [12–14, 16]. Some recent papers have noted a high incidence of leaks in natural gas distribution systems in two U.S. east coast cities [23, 24], but these new studies have yet placed an emission flux estimate on these leaks. Another study demonstrated very high methane emissions from fossil fuel sources in Los Angeles but could not distinguish between downstream natural gas emissions and other sources [25]. Given the age of gas pipelines and distribution systems in the United States, it should come as no surprise that leakage may be high [8, 18, 19]. Half of the high-pressure pipelines in the United States are older than 50 years [18], and parts of the distribution systems in many northeastern cities consist of cast-iron pipes laid down a century ago [24].

4 While one of the papers in Table 1 by Cathles and his colleagues [17], characterized our methane emission estimates as too high and "at odds with previous studies," that in fact is not the case. As noted above, both our downstream and upstream estimates for conventional gas are in excellent agreement with one of the few previous peer-reviewed studies [2]. Furthermore, our upstream emissions are in good agreement with the majority of the papers published in 9 months after

ours: for conventional gas, our mean estimate of 1.4% compares with the mean for all the other studies in Table 1 of 1.33%; if we exclude the very low estimate from Stephenson et al. [14], which was based on an analysis of what the gas industry is capable of doing rather than on any new measurements, and also the relatively low estimate from Cathles et al. [17], which was based on the assumption that the gas industry would not vent gas for economic and safety issues (see critique of this in [18]), the mean of the other four studies is 1.7, or almost twice as high as the Cathles et al. [17] estimate and 20% higher than our estimate. For shale gas, again excluding Stephenson et al. [14] and Cathles et al. [17] as well as our estimate, the other four studies in Table 1 have a mean estimate of 2.3, a value 2.5-fold greater than that from Cathles et al. [17] and 30% less than our mean estimate. From this perspective, the estimates of Cathles et al. [17] appear to be greater outliers than are ours.

Since 2012, many new papers have produced additional primary data (Fig. 2). Two of these found very high upstream methane emission rates from unconventional gas fields (relative to gross methane production), 4% for a tight-sands field in Colorado [26] and 9% for a shale gas field in Utah [27], while another found emissions from a shale gas field in Pennsylvania to be broadly consistent with the emission factors we had published in our 2011 paper [28]. All three of these studies inferred rates from atmospheric data that integrated a large number of wells at the basin scale. The new Utah data [27] are much higher than any of the estimates previously published for upstream emissions from unconventional gas fields (Fig. 2), while the measurement for the Colorado tight-sands field [26] overlaps with our high-end estimate for upstream unconventional gas emissions in Howarth et al. [8]. The Utah and Colorado studies may not be representative of the typical methane emissions for the entire United States, in part, because they focused on regions where they expected high methane fluxes based on recent declines in air quality. But I agree with the conclusion of Brandt and his colleagues [29] that the "bottom-up" estimation approaches that we and all the other papers in Table 1 employed are inherently likely to lead to underestimates, in part, because some components of the natural gas system are not included. As one example, the recent Pennsylvania study, which quantified fluxes from discrete locations on the ground by mapping methane plumes from an airplane, found very high emissions from many wells that were still being drilled, had not yet reached the shale formation, and had not yet been hydraulically fractured [28]. These wells represented only 1% of the wells in the area but were responsible for 6–9% of the regional methane flux from all sources. One explanation is that the drill rigs encountered pockets of shallower gas and released this to the atmosphere. We, the EPA, and all of the papers in Table 1 had assumed little or no methane emissions from wells during this drilling phase.

Allen and colleagues [30] published a comprehensive study in 2013 of upstream emissions for both conventional and unconventional gas wells for several regions in the United States, using the same basic bottom-up approach as the joint EPA-industry study of 1996 used [5]. As with that earlier effort, this new study relied heavily on industry cooperation, and was funded largely by industry with coordination provided by the Environmental Defense Fund. For the United States as a whole at the

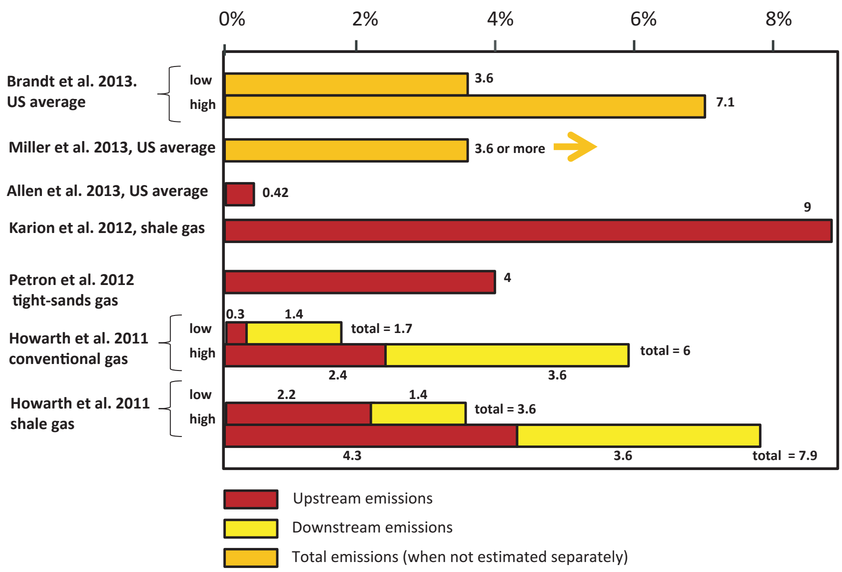

Figure 2. Comparison of recent new data on methane emissions compared to the estimates published in Howarth et al. [8]. Some of the new data are for upstream emissions, while others give only averages for natural gas systems in the United States. No new measurements for downstream emissions alone have been published since 2005 [8, 26, 27, 29, 30, 32].

time of their study, Allen et al. [30] concluded that upstream methane emissions were only 0.42% of the natural gas production by the wells (Fig. 2), a value at the low end of those seen in Table 1. Using the low-end estimates, "best-case" scenarios for upstream emissions from Howarth et al. [8] and the mix of shale gas and conventional gas produced in the United States in 2012, I estimate the U.S. national best-case emission rate would be 0.5%, or similar to that observed by Allen and colleagues. It should not be surprising that their study, in relying on industry access to their sampling points, ended up in fact measuring the best possible performance by industry.

In 2013, the EPA reduced their emission estimates for the oil and gas industry, essentially halving their upstream emissions for average natural gas systems from 1.8% to 0.88% for the year 2009 (with the mix of conventional and unconventional gas for that year) from what they had reported in 2011 and 2012; the EPA estimate for downstream emissions remained at 0.9%, giving a total national emission estimate of 1.8%. EPA took this action to decrease their emission factors for upstream emissions despite the publication in 2012 of the methane emissions from a Colorado field [26] and oral presentations at the American Geophysical Union meeting in December 2012 of the results subsequently published by Karion and colleagues [27] and Caulton and colleagues [28], all of which would have suggested higher emissions, perhaps spectacularly so. As is discussed by Karion et al. [27], the decrease in the upstream methane emissions by EPA in 2013 was driven by a non-peer-reviewed industry report [31] which argued that emissions from liquid unloading and during refracturing of unconventional wells were far lower than used in the EPA [11] assessment. At least in part in response to these changes by EPA, the Inspector General for the EPA concluded that the agency needs improvements in their approach to estimating emissions from the natural gas industry [9].

An important paper published late in 2013 [32] indicates the EPA made a mistake in reducing their emission estimates earlier in the year. In this analysis, the most comprehensive study to date of methane sources in the United States, Miller and colleagues used atmospheric methane monitoring data for 2007 and 2008 – 7710 observations from airplanes and 4984 from towers from across North America – together with an inverse model to assess total methane emissions nationally from all sources. They concluded that rather than reducing methane emission terms between their 2011 and 2013 inventories, EPA should have increased anthropogenic methane emission estimates, particularly for the oil and gas industry and for animal agriculture operations. They stated that methane emissions from the United States oil and gas industry are very likely two-fold greater or more than indicated by the factors EPA released in 2013 [32]. This suggests that total methane emissions from the natural gas industry were at least 3.6% in 2007 and 2008 (Fig. 2).

In early 2014, Brandt and his colleagues [29] reviewed the technical literature over the past 20 years on methane emissions from natural gas systems. They concluded that "official inventories consistently underestimate actual methane emissions," but also suggested that the very high estimates from the top–down studies in Utah and Colorado [26, 27] "are unlikely to be representative of typical [natural gas] system leakage rates." In the supplemental materials for their paper, Brandt et al. [29] state that methane emissions in the United States from the natural gas industry are probably greater than the 1.8% assumed by the EPA by an additional 1.8–5.4%, implying an average rate between 3.6% and 7.1% (mean = 5.4%) [33] (Fig. 2).

This recent literature suggests to me that the emission estimates we published in Howarth et al. [8] are surprisingly robust, particularly for conventional natural gas (Fig. 2). The results from two of the recent top–down studies [26, 27] indicate our estimates for unconventional gas may have been too low. Partly in response to our work and their own reanalysis of methane emissions from shale gas wells, EPA has now promulgated new regulations that will as of January 2015 reduce methane emissions at the time of well completions, requiring capture and use of the gas instead in most cases. Some wells are exempt, and the regulation does not apply to venting of methane from oil wells, including shale oil wells, which often have associated gas. Nonetheless, the regulations are an important step in the right direction, and will certainly help, if they can be adequately enforced. Even still, though, results such as those from the Pennsylvania flyover showing high rates of methane emission during the drilling phase of some shale gas wells [28] suggest that methane emissions from shale gas may remain at levels higher than from conventional natural gas.

The GWP of Methane

While methane is far more effective as a greenhouse gas than carbon dioxide, methane has an atmospheric lifetime of only 12 years or so, while carbon dioxide has an effective influence on atmospheric chemistry for a century or longer [34]. The time frame over which we compare the two gases is therefore critical, with methane becoming relatively less important than carbon dioxide as the timescale increases. Of the major papers on methane and the GHG for conventional natural gas published before our analysis for shale gas, one modeled the relative radiative forcing by methane compared to carbon dioxide continuously over a 100-year time period following emission [2], and two used the global warming approach (GWP) which compares how much larger the integrated global warming from a given mass of methane is over a specified period of time compared to the same mass of carbon dioxide. Of the two that used the GWP approach, one showed both 20-year and 100-year GWP analyses [3] while another used only a 100-year GWP time frame [4]. Both used GWP values from the Intergovernmental Panel on Climate Change (IPCC) synthesis report from 1996 [35], the most reliable estimates at the time their papers were published. In subsequent reports from the IPCC in 2007 [36] and 2013 [34] and in a paper in *Science* by workers at the NASA Goddard Space Institute [37], these GWP values have been substantially increased, in part, to account for the indirect effects of methane on other radiatively active substances in the atmosphere such as ozone (Table 2).

In Howarth et al. [8], we used the GWP approach and closely followed the work of Lelieveld and colleagues [3] in presenting both integrated 20 and 100 year periods, and in giving equal credence and interpretation to both timescales. We upgraded the approach by using the most recently published values for GWP at that time [37].

Table 2. Comparison of the timescales considered in comparing the global warming consequences of methane and carbon dioxide.

Publication	Timescale considered	20-year GWP	100-year GWP
IPCC [35]	**20 and 100 years**	**56**	**21**
Hayhoe et al. [2]	0–100 years	NA	NA
Lelieveld et al. [3]	20 and 100 years	56	21
Jamarillo et al. [4]	100 years	–	21
IPCC [36]	**20 and 100 years**	**72**	**25**
Shindell et al. [37]	**20 and 100 years**	**105**	**33**
Howarth et al. [8]	20 and 100 years	105	33
Hughes [20]	20 and 100 years	105	33
Venkatesh et al. [12]	100 years	–	25
Jiang et al. [13]	100 years	–	25
Wigley [38]	0–100 years	NA	NA
Stephenson et al. [14]	100 years	–	25
Hultman et al. [15]	20 and 100 years	72, 105	25, 44
Skone et al. [39]	100 years	–	25
Burnham et al. [16]	100 years	–	25
Cathles et al. [17]	100 years	–	25
Alvarez et al. [40]	0–100 years	NA	NA
IPCC [34]	**10, 20, and 100 years**	**86**	**34**
Brandt et al. [29]	100 years	–	25

Studies are listed chronologically by time of publication. Values for the global warming potentials at 20 and 100 years given, when used in the studies. NA stands for not applicable and is shown when studies did not use the global warming potential approach. Dashes are shown for studies that did not consider the 20-year GWP. Studies that are bolded provided primary estimates on global warming potentials, while other studies are consumers of this information.

These more recent GWP values increased the relative warming of methane compared to carbon dioxide by 1.9-fold for the 20-year time period (GWP of 105 vs. 56) and by 1.6-fold for the 100-year time period (GWP of 33 vs. 21; Table 2). Our conclusion was that for the 20-year time period, shale gas had a larger GHG than coal or oil even at our low-end estimates for methane emission (Fig. 1); conventional gas also had a larger GHG than coal or oil at our mean or high-end methane emission estimates, but not at the very low-end range for methane emission (the best-case, low-emission scenario). At the 100-year timescale, the influence of methane was much diminished, yet at our high-end methane emissions, the GHG of both shale gas and conventional gas still exceeded that of coal and oil (Fig. 1).

Of nine new reports on methane and natural gas published in 9 months after our April 2011 paper [8], six only considered the 100-year time frame for GWP, two used both a 20- and 100-year time frame, and one used a continuous modeling of radiative forcing over the 0–100 time period (Table 2). Of the six papers that only examined the 100-year time frame, all used the lower GWP value of 25 from the 2007 IPCC report rather than the higher value of 33 published by Shindell and colleagues in 2009 that we had used; this higher value better accounts for the indirect effects of methane on global warming. Many of these six papers implied that the IPCC dictated a focus on the 100-year time period, which is simply not the case: the IPCC report from 2007 [36] presented both 20- and 100-year GWP values for methane. And two of these six papers criticized our inclusion of the 20-year time period as inappropriate [14, 17]. I strongly disagree with this criticism. In the time since April 2011 I have come increasingly to believe that it is essential to consider the role of methane on timescales that are much shorter than 100 years, in part, due to new science on methane and global warming presented since then [34, 41, 42], briefly summarized below.

The most recent synthesis report from the IPCC in 2013 on the physical science basis of global warming highlights the role of methane in global warming at multiple timescales, using GWP values for 10 years in addition to 20 and 100 years (GWP of 108, 86, and 34, respectively) in their analysis [34]. The report states that "there is no scientific argument for selecting 100 years compared with other choices," and that "the choice of time horizon …. depends on the relative weight assigned to the effects at different times" [34]. The IPCC further concludes that at the 10-year timescale, the current global release of methane from all anthropogenic sources exceeds (slightly) all anthropogenic carbon dioxide emissions as agents of global warming; that is, methane emissions are more important (slightly) than carbon dioxide emissions for driving the current rate of global warming. At the 20-year timescale, total global emissions of methane are equivalent to over 80% of global carbon dioxide emissions. And at the 100-year timescale, current global methane emissions are equivalent to slightly less than 30% of carbon dioxide emissions [34] (Fig. 3).

This difference in the time sensitivity of the climate system to methane and carbon dioxide is critical, and not widely appreciated by the policy community and even some climate scientists. While some note how the long-term momentum of the climate system is driven by carbon dioxide [15], the climate system is far more immediately responsive to changes in methane (and other short-lived radiatively active materials in the atmosphere, such as black carbon) [41]. The model published in 2012 by Shindell and colleagues [41] and adopted by the United Nations [42] predicts that unless emissions of methane and black carbon are reduced immediately, the Earth's average surface temperature will warm by 1.5°C by about 2030 and by 2.0°C by 2045 to 2050 whether or not carbon dioxide emissions are reduced. Reducing methane and black carbon emissions, even if carbon dioxide is not controlled, would significantly slow the rate of global warming and postpone reaching the 1.5°C and 2.0°C marks by 15–20 years. Controlling carbon dioxide as well as methane and black carbon emissions further slows the rate of global warming after 2045, through at least 2070 [41, 42] (Fig. 4).

Why should we care about this warming over the next few decades? At temperatures of 1.5–2.0°C above the 1890–1910 baseline, the risk of a fundamental change in the Earth's climate system becomes much greater [41–43], possibly leading to runaway feedbacks and even more global warming. Such a result would dwarf any possible benefit from reductions in carbon dioxide emissions over the next few decades (e.g., switching from coal to natural gas, which does reduce carbon dioxide but also increases methane emissions). One of many mechanisms for such catastrophic change is the melting of methane clathrates in the oceans or melting of permafrost in the Arctic. Hansen and his colleagues [43, 44] have suggested that warming of the Earth by 1.8°C may trigger a large and rapid increase in the release of such methane. While there is a wide range in both the magnitude and timing of projected carbon release from thawing permafrost and melting clathrates in the literature [45], warming consistently leads to greater release. This release can in turn cause a feedback of accelerated global warming [46].

To state the converse of the argument: the influence of today's emissions on global warming 200 or 300 years into the future will largely reflect carbon dioxide, and not

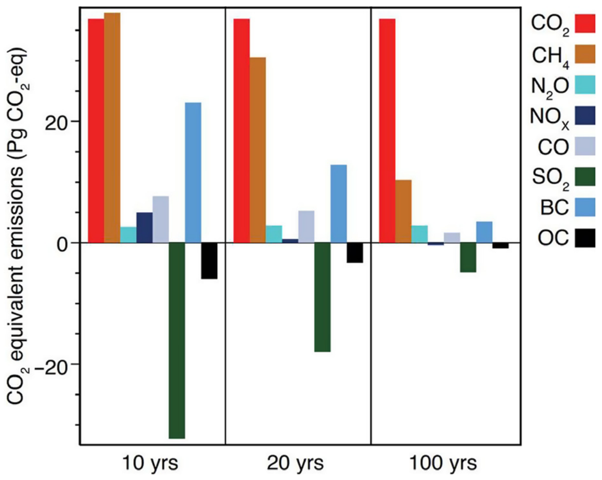

Figure 3. Current global greenhouse gas emissions, as estimated by the IPCC [34], weighted for three different global warming potentials and expressed as carbon dioxide equivalents. At the 10-year time frame, global methane emissions expressed as carbon dioxide equivalents actually exceed the carbon dioxide emissions. Adapted from [34].

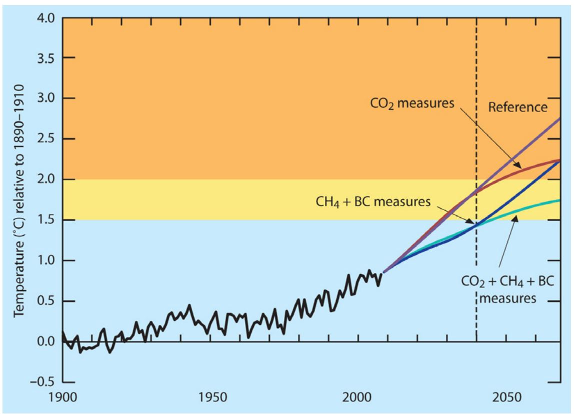

Figure 4. Observed global mean temperature from 1900 to 2009 and projected future temperature under four scenarios, relative to the mean temperature from 1890 to 1910. The scenarios include the IPCC [36] reference, reducing carbon dioxide emissions but not other greenhouse gases ("CO_2 measures"), controlling methane, and black carbon emissions but not carbon dioxide ("CH_4 + BC measures"), and reducing emissions of carbon dioxide, methane, and black carbon ("CO_2 + CH_4 + BC measures"). An increase in the temperature to 1.5–2.0°C above the 1890–1910 baseline (illustrated by the yellow bar) poses risk of passing a tipping point and moving the Earth into an alternate state for the climate system. The lower bound of this danger zone, 1.5° warming, is predicted to occur by 2030 unless stringent controls on methane and black carbon emissions are initiated immediately. Controlling methane and black carbon shows more immediate results than controlling carbon dioxide emissions, although controlling all greenhouse gas emissions is essential to keeping the planet in a safe operating space for humanity. Adapted from [42].

methane, unless the emissions of methane lead to tipping points and a fundamental change in the climate system. And that could happen as early as within the next two to three decades.

An increasing body of science is developing rapidly that emphasizes the need to consider methane's influence over the decadal timescale, and the need to reduce methane emissions. Unfortunately, some recent guidance for life cycle assessments specify only the 100-year time frame [47, 48], and the EPA in 2014 still uses the GWP values from the IPCC 1996 assessment and only considers the 100-year time period when assessing methane emissions [49]. In doing so, they underestimate the global warming significance of methane by 1.6-fold compared to more recent values for the 100-year time frame and by four to fivefold compared to the 10- to 20-year time frames [34, 37].

Climate Impacts of Different Natural Gas Uses

In Howarth et al. [8], we compared the greenhouse gas emissions of shale gas and conventional natural gas to those of coal and oil, all normalized to the same amount of heat production (i.e., g C of carbon dioxide equivalents per MJ of energy released in combustion). We also noted that the specific comparisons will depend on how the fuels are used, due to differences in efficiencies of use, and briefly discussed the production of electricity from coal versus shale gas as an example; electric-generating plants on average use heat energy from burning natural gas more efficiently than they do that from coal, and this is important although not usually dominant in comparing the GHGs of these fuels [8, 18–20]. We presented our main conclusions in the context of the heat production (Fig. 1), though, because evaluating the GHGs of the different fossil fuels for all of their major uses was beyond the scope of our original study, and electricity production is not the major use of natural gas. This larger goal of separately evaluating the GHGs of all the major uses of natural gas has not yet been taken on by other research groups either.

In Figure 5 (left-hand panel), I present an updated comparison of the GHGs of natural gas, diesel oil, and coal based on the best available information at this time (April 2014). Values are expressed as g C of carbon dioxide equivalents per MJ of energy released as in our 2011 paper [8] and Figure 1. The methane emissions in Figure 5 are the mean and range of estimates from the recent review by Brandt and colleagues [29] (see Fig. 2), normalized to carbon dioxide equivalents using the 20-year mean GWP value of 86 from the latest IPCC assessment [34]. As noted above, I believe the 20-year GWP is

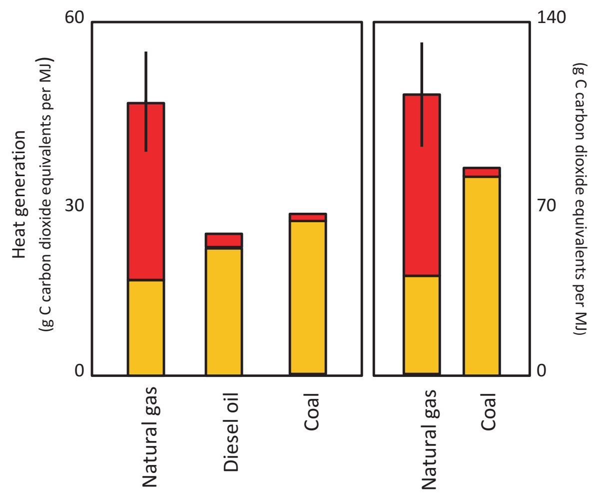

Figure 5. Comparison of the greenhouse gas footprint for using natural gas, diesel oil, and coal for generating primary heat (left) and for using natural gas and coal for generating electricity (right). Direct and indirect carbon dioxide emissions are shown in yellow and are from Howarth et al. [8], while methane emissions shown as g C of carbon dioxide equivalents using the 2013 IPCC 20-year GWP [34] are shown in red. Methane emissions for natural gas are the mean and range for the U.S. national average reported by Brandt and colleagues [29] in their supplemental materials. Methane emissions for diesel oil and for coal are from Howarth et al. [8] For the electricity production, average U.S. efficiencies of 41.8% for gas and 32.8% for coal are assumed [20]. Several studies present data on emissions for electricity production in other units. One can convert from g C of CO_2-equivalents per MJ to g CO_2-equivalents per kWh by multiplying by 13.2. One can convert from g C of CO_2-equivalents per MJ to g C of CO_2-equivalents per kWh by multiplying by 3.6.

an appropriate timescale, given the urgent need to control methane emissions globally. Estimates for coal and diesel oil are from our 2011 paper [8], using data for surface-mined coal since that dominates the U.S. market [20]. The direct and indirect emissions of carbon dioxide are combined and are the same values as in Howarth et al. [8] and Figure 1. Direct carbon dioxide emissions follow the High Heating Value convention [2, 8]. Clearly, using the best available data on rates of methane emission [29], natural gas has a very large GHG per unit of heat generated when considered at this 20-year timescale.

Of the studies listed in Tables 1 and 2 published after our 2011 paper [8], most focused just on the comparison of natural gas and coal to generate electricity, although one also considered the use of natural gas as a long-distance transportation fuel [40]. For context, over the period 2008–2013 in the United States, 31% of natural gas has been used to generate electricity and 0.1% as a transportation fuel [50]. None of the studies listed in Tables 1 and 2, other than Howarth et al. [8], considered the use of natural gas for its primary use: as a source of heat. In the United States over the last 6 years, 32% of natural gas has been used for residential and commercial heating and 28% for industrial process energy [50]. The focus on electricity is appropriate if the only question at hand is "how does switching out coal for natural gas in the generation of electricity affect greenhouse gas emissions?" However, policy approaches have pushed other uses of natural gas – without any scientific support – as a way to reduce greenhouse gas emissions, apparently on the mistaken belief that the analysis for electricity generation applied to these other uses. Before exploring some of these other uses of natural gas, I would like to further explore the question of electricity generation.

Many of the papers listed in Tables 1 and 2 concluded that switching from coal to natural gas for generating electricity has a positive influence on greenhouse gas emissions. Note, though, that for almost all of these papers, the conclusion was driven by a focus on only the 100-year timescale [4, 12–14, 16, 17, 29, 39], on a very low assumed level of methane emission [4, 12–14, 17, 39], or both. The differences in efficiency of use in electric power plants, comparing either current average plants or best possible technologies, are relatively small compared to the influence of the GWP on the calculation [8, 18, 20, 40]. Using a 20-year GWP framework and the methane emission estimates from Howarth et al. [8], the GHG from generating electricity with natural gas is larger than that from coal [8, 18–20]. Alvarez and colleagues [40] concluded that for electricity generation, the GHG of using natural gas was less than for coal for all time frames only if the rate of methane leakage was less than 3.2%. Their analysis used the estimates for the radiative forcing of methane from the IPCC 2007 synthesis [36], and if we correct their estimate for the data in the 2013 IPCC assessment [34], this "break-even point" becomes 2.8%. If we further consider the uncertainty in the radiative forcing of methane of 30% or more [34], this "break-even" value becomes a range of 2.4–3.2%.

In Figure 5 (right-hand panel), I compare the GHGs of natural gas and coal when used to generate electricity, again using the High Heating Value convention [2, 8], the latest IPCC value for the 20-year GWP [34] and the range of methane emission estimates reported by Brandt and colleagues [29]. No distinction is made for less downstream emissions for the pipelines that feed electric power plants, as is assumed in several other studies [12–14, 16], simply because no data exist with which to tease apart downstream emissions specific for electric power generation [51]. This analysis uses the average efficiency for electric power plants currently operating in the United States, 41.8% for gas and 32.8% for coal [20]. The emissions per unit of energy produced as electricity are higher than for the heat generation alone, due to these corrections for efficiency. Although the difference in the footprints for using the two fuels is less for the electricity comparison than for the comparison for heat generation, at this 20-year timescale the GHG of natural gas remains greater than that of coal, even at the low-end methane emission estimate. This conclusion still holds when one compares the fuels using the best available technologies (50.2% efficiency for natural gas and 43.3% for coal [20]); the emissions per unit of electricity generated decrease for both by approximately the same amount.

For the dominant use of natural gas – heating for water, domestic and commercial space, and industrial process energy – the analysis we presented in our 2011 paper [8] and shown in Figure 1 remains the only published study before this new analysis shown in Figure 5 (left-hand panel). The updated version shown here compellingly indicates natural gas is not a climate-friendly fuel for these uses. However, the greenhouse gas consequences may in fact be worse than Figure 5 or Howarth et al. [8] indicate, as I discuss next.

A recent study supported by the American Gas Foundation promoted the in-home use of natural gas over electricity for appliances (domestic hot water, cooking) because of a supposed benefit for greenhouse gas emissions [52]. The report argues that an in-home natural gas appliance will have a higher efficiency in using the fuel (up to 92%) compared to the overall efficiency of producing and using electricity ("only about 40%," according to this study). However, they did not include methane emissions in their analysis, nor did they consider the extremely high efficiencies available for some electrical appliances, such as in-home air-sourced heat pumps for domestic hot water. For a given input of electricity, such heat pumps can produce 2.2-times more heat energy, since they are harvesting and concentrating heat from the local environment [53]. In a comparison of using in-home gas-fired water heaters or in-home high-efficiency electric heat pumps, with the electricity for the heat pumps generated by burning coal, the heat pumps had a lower GHG than did in-home use of gas if the emission rate for methane was greater than 0.7% for a 20-year GWP or 1.3% for a 100-year GWP [51]. Using the mean methane emission estimate from Howarth et al. [8] for conventional natural gas (Fig. 2) and a 20-year GWP, the in-home natural gas heater had a GHG that was twice as large as that of the heat pump [51]. Of course, an in-home heat pump powered by electricity from renewable sources such as wind and solar would have a far smaller GHG yet [54].

What about other uses of natural gas? The "Natural Gas Act," a bill introduced in the United States Congress in 2011 with bipartisan support and the backing of President Obama, would have provided tax subsidies to encourage the replacement of diesel fuel by natural gas for long-distance trucks and buses; the bill did not pass, in part because conservatives opposed it as "market distorting" [55, 56]. In Quebec, industry has claimed that this replacement of diesel by shale gas would reduce greenhouse gas emissions by up to 30% [57]. However, in contrast to a possible advantage in replacing coal with natural gas for electricity generation (if methane emissions can be kept low enough), using natural gas to replace diesel fuel as a long-distance transportation fuel would greatly increase greenhouse emissions [29, 40]. In part, this is because the energy of natural gas is used with less efficiency than diesel in truck engines. Furthermore, although methane emissions from transportation systems have not been well measured, one could imagine significant emissions during refueling operations for buses and trucks, as well as from venting of on-vehicle natural gas tanks to keep gas pressures significantly safe during warm weather. Despite the findings of Alvarez and colleagues published in 2012 [40], the EPA continues to indicate that switching buses from diesel fuel to natural gas reduces greenhouse gas emissions [58].

Concluding Thoughts

By 1950, which is about the time I was born, human activity had contributed enough greenhouse gases to the atmosphere to cause a radiative forcing – the driving factor behind global warming – of 0.57 watts m^{-2} compared to before the industrial revolution [34]. Thirty years later, in 1980 when I taught my first course on the biosphere and global change, this human influence had doubled the anthropogenic radiative forcing, to 1.25 watts m^{-2} [34]. And another 30 years later, the continued release of greenhouse gases by humans has again doubled the forcing, now at 2.29 watts m^{-2} or fourfold greater than just 60 years ago [34]. The temperature of the Earth continues to rise in response at an alarming rate, and the climate scientists tell us we may reach dangerous tipping points in the climate system within just a few decades [34, 41, 42]. Is it too late to begin a serious reduction in greenhouse gas emissions? I sincerely hope not, although surely society has been very slow to respond to this risk. The use of fossil fuels is the major cause of greenhouse gas emissions, and any genuine effort to reduce emissions must begin with fossil fuels.

Is natural gas a bridge fuel? At best, using natural gas rather than coal to generate electricity might result in a very modest reduction in total greenhouse gas emissions, if those emissions can be kept below a range of 2.4–3.2% (based on [40], adjusted for the latest information on radiative forcing of methane [34]). That is a big "if," and one that will require unprecedented investment in natural gas infrastructure and regulatory oversight. For any other foreseeable use of natural gas (heating, transportation), the GHG is larger than if society chooses other fossil fuels, even with the most stringent possible control on methane emissions, if we view the consequences through the decadal GWP frame. Given the sensitivity of the global climate system to methane [41, 42], why take any risk with continuing to use natural gas at all? The current role of methane in global warming is large, contributing 1.0 watts m^{-2} out of the net total 2.29 watts m^{-2} of radiative forcing [34].

Am I recommending that we continue to use coal and oil, rather than replace these with natural gas? Not at all. Society needs to wean itself from the addiction to fossil fuels as quickly as possible. But to replace some fossil fuels (coal, oil) with another (natural gas) will not suffice as an approach to take on global warming. Rather, we should embrace the technologies of the 21st Century, and convert our energy systems to ones that rely on wind, solar, and water power [59, 60, 61]. In Jacobson et al. [54], we lay out a plan for doing this for the entire state of New York, making the state largely free of fossil fuels by 2030 and completely free by 2050. The plan relies only on technologies that are commercially available at present, and includes modern technologies such as high-efficiency heat pumps for domestic water and space heating. We estimated the cost of the plan over the time frame of implementation as less than the present cost to the residents of New York from death and disease from fossil fuel caused air pollution [54]. Only through such technological conversions can society truly address global change. Natural gas is a bridge to nowhere.

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Conflict of Interest

None declared.

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