Approved: 02/20/08
Date

MINUTES OF THE SELECT COMMITTEE ON ENERGY & ENVIRONMENT FOR THE FUTURE

The meeting was called to order by Chairman Don Myers at 1:30 PM on February 18, 2008 in Room 784 of the Docking State Office Building.

All members were present except:
Vaughn Flora, Excused
Jason Watkins, Excused.

Committee staff present:
Mike Corrigan, Revisor of Statutes Office
Melissa Doeblin, Revisor of Statutes Office
Raney Gilliland, Kansas Legislative Research Department
Mary K. Galligan, Kansas Legislative Research Department
Ryan Hoffman, Kansas Legislative Research Department
Barbara Lewerenz, Committee Assistant

Conferees appearing before the committee: none

Others attending:
See attached list.

Chairman Myers introduced the representatives from the Revisor of Statutes Office and the Kansas Legislative Research Department. He announced that the Select Committee on Energy and Environment for the Future will be held at 1:30 p.m. in the Docking Building, Room 784. He asked that members with conflicting meeting dates ask to be excused.

A bill has been introduced by Federal and State that will be assigned back to this committee for work. Work on the Agenda continues with speakers Larry Holloway, Chief of Energy Operations, Kansas Corporation Commission and Liz Brosius, Director, Kansas Energy Council speaking to the committee on February 20, and Rep. Tom Sloan on February 21. Paul Genoa, Director, Environmental Policy, Nuclear Energy Institute, Washington, D.C. will speak on March 6.

Chairman Myers recognized Rep. Carl Holmes who gave a briefing on the present base load power supply and the projected increase for Kansas, present electric transmission and future needs. Rep. Holms presented information on the major electric generation facilities currently operating in Kansas using data from the Department of Energy's Energy Information Administration for 2006 and 2007 (Attachment 1).

Discussion revealed that Kansas is currently using about the same amount of energy as is being produced in the state. Transitioning to more wind power, with gas to back it up, will increase the price of gas. Today gas has tripled from ten years ago. Ten years ago the price of gas and oil were equal. Today oil is double the price of gas. If gas prices reach the level of oil prices, heating cost will double. This will have a negative effect on the economy.

There are proposals being formed with Canada for pipelines that would bring synthetic oil into the United States going through Northeastern Kansas and possibly Western Kansas. Two out of every three barrels of oil that go through Kansas refineries come from sources outside of Kansas. China is lobbying for Canadian oil also. The U.S. uses 25 percent of the world's oil supply. Extraction of shale oil is being explored, but so far the cost is prohibitive.

The United States has 25-27 percent of the world's coal supply. Russia has close to the same amount It is estimated that there is a 250 to 400 year supply of coal in the U.S. The global economy determines the price of imported gas and oil.

France depends on nuclear power for 80 percent of energy needs. About 95 percent of the fuel can be reprocessed. SE New Mexico is building a processing plant for uranium to be made into fuel rods for nuclear power plants. They also have a site where nuclear waste from the military is buried. Russia is sending nuclear war heads for reprocessing into nuclear fuel to a plant in Savannah.

Rep.Holmes spoke about the Kansas Energy Commission. The commission consists of three subcommittees with the following goals: define the direction the energy council should go; look at the agreement signed by Kansas and the Midwest Governors Association on greenhouse gases; and dealing with electricity by looking at base load and the future demands of electricity for the next 20 - 30 years.

Chairman Myers asked that, due to time constraints, the committee refrain from discussion on the Holcomb Plant, global warming, carbon tax and ancillary items that will bog down the committee.

Meeting Adjourned.

The next meeting will be February 20, 2008.

House Select Committee on
Energy and Environment for the Future

GUEST LIST **DATE** 2-18-08

Your Name	Representing
Ray Hanild	KCC
Paul Johnson	Ks Cath Conf
Hein Law Firm ↔	Lindsey Douglas
John Butler	Pete Gaag ... ; Assoc.
Callie Cane	Kearney & Associates Inc
Mark Schreiber	Westar
Paul Snider	KCPL
Steve Johnson	ONEOK
Shari Albrecht	KDHE

Kansas Electric Generation: Summary of Existing Power Plants
Kansas Energy Council Staff Summary
Prepared for the KEC Electricity Committee, February 2008

The following table contains information on the major electric generation facilities currently operating in Kansas, exclusive of intermittent power generation (e.g., wind facilities). The summary is based primarily on utility data submitted to the Department of Energy's Energy Information Administration (EIA) in EIA Forms 860 and 906-920 (for 2006 and 2007).

Utility / Operator	Power Plant / Unit / Primary Fuel Source (Type: B = Baseload, I = Intermediate, P = Peaking)	County	Nameplate Capacity (MW)	Initial Year of Operation	Net Generation (MWh) 10/06-10/07 *(tons CO2 per MWh)*
Wolf Creek Nuclear Generating Corp. (owned by Westar, KCP&L, KEPCo)	Wolf Creek 1: Nuclear (B)	Coffey	1,235.7	1985	10,071,556 *(0)*
Westar	Jeffrey EC 1: Coal (B) 2: Coal (B) 3: Coal (B)	Pottawatomie	 720 720 720	 1978 1980 1983	15,202,432 *(1.16)*
	Lawrence EC 3: Coal (B) 4: Coal (B) 5: Coal (B)	Douglas	 49 114 403	 1955 1960 1971	3,507,588 *(1.18)*
	Hutchinson EC GT1: Natural gas (P) GT2: Natural gas (P) GT3: Natural gas (P) GT4: distillate fuel oil (?) H1DG: distillate fuel oil (?)* ST1: natural gas (P) ST2: natural gas (P) ST3: natural gas (P) ST4: natural gas (P)	Reno	 71 71 71 86 2.7 23 23 35 172	 1974 1974 1974 1975 1983 1950 1950 1951 1965	134,869 *(0.71)*
	Abilene EC GT1: Natural gas (P)	Dickinson	49	1973	0?
	Tecumseh EC 1: Natural gas (P) 2: Natural gas (P) 7: Natural gas (B) 8: Coal (B)	Shawnee	 29 29 82 150	 1972 1972 1957 1962	 0? 1,431,798 *(1.22)*

Select Committee on Energy
+ Environment for the Future
2/18/08
Attachment # 1

Utility / Operator	Power Plant / Unit / Primary Fuel Source (Type: B = Baseload, I = Intermediate, P = Peaking)	County	Nameplate Capacity (MW)	Initial Year of Operation	Net Generation (MWh)/ *Tons of CO2 per MWh,* 10/06-10/07
KCP&L	LaCygne 1: Coal (B) 2: Coal (B)	Linn	 893 685	 1973 1977	10,296,491 *(1.07)*
	Osawatomie 1: Natural gas (P)	Miami	 90	 2003	9,172 *(0.81)*
	West Gardner 1: Natural gas (I) 2: Natural gas (I) 3: Natural gas (I) 4: Natural gas (I)	Johnson	 91.3 91.2 91.3 91.3	 2003 2003 2003 2003	99,552 *(0.78)*
KCBPU	Quindaro GT1: Natural gas (P) GT2: Distillate fuel oil (P) GT3: Distillate fuel oil (P) ST1: Coal (B) ST2: Coal (B)	Wyandotte	 17.9 65.7 65.7 81.6 157.5	 1969 1974 1977 1965 1971	 2,560 (1.83) 1,162,098 *(1.14)*
	Nearman Creek 1: Coal (B) CT4: Natural gas (P)	Wyandotte	 261 94	 1981 2006	 1,597,931 *(1.18)* 29,812 *(0.75)*
KG&E	Gordon Evans 1: Natural gas (P) 2: Natural gas (P) 5: Distillate fuel oil (P)* GT1: Natural gas (P) GT2: Natural gas (P) GT3: Natural gas (P)	Sedgwick	 136 390 2.9 98.3 98.3 178.5	 1961 1967 1969 2000 2000 2001	543,319 *(0.09)*
	Murray Gill 1: Natural gas (P) 2: Natural gas (P) 3: Natural gas (P) 4: Natural gas (P)	Sedgwick	 46 75 114 114	 1952 1954 1956 1959	 147,453 *(0.79)*
	Neosho 3: Natural gas (P)	Labette	 69	 1954	 0?
Sunflower	Holcomb 1: Coal (B)	Finney	348.7	1983	2,829,430 *(1.09)*
	Garden City GC3: Natural gas (I)* S2: Natural gas (I) S3: Natural gas (I)* S4: Natural gas (I) S5: Natural gas (I)	Finney	 11.5 97.9 16 71.2 71.2	 1961 1973 1968 1976 1979	 48,757 *(0.77)*

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Utility / Operator	Power Plant / Unit / Primary Fuel Source (Type: B = Baseload, I = Intermediate, P = Peaking)	County	Nameplate Capacity (MW)	Initial Year of Operation	Net Generation (MWh)/ *Tons of CO2 per MWh,* 10/06-10/07
Sunflower (con't)	Cimarron River** 1: Natural gas (I) 2: Natural gas (P)	Seward	50 (61)*** 15	1963 1967	? ?
	Clifton** 1: Natural gas (P) 2: Distillate fuel oil (P)	Washington	85 (73)*** 15	1974 1974	? ?
	Fort Dodge 4: Natural gas (load following)***	Ford	145	1968	?
	Great Bend 3: Natural gas (I)***	Barton	98	1963	?
	S-2: Natural gas (I)***		98	1973	?
	S-3: Natural gas (P)***		14	1968	?
	S-4: Natural gas (P)***		51	1976	?
	S-5: Natural gas (P)***		53	1963	?
	GC-3: Natural gas (I)***		9	1962	?
*Mid-Kansas Electric Company**** *	*Judson Large 4: Natural gas (?)** *	*Ford*	*149*	*1969*	*?*
	*Arthur Mullergren 3: Natural gas (?)** *	*Barton*	*81.6*	*1963*	*?*
Empire	Riverton 10: Distillate fuel oil (?) 11: Distillate fuel oil (?) 7: Coal (B) 8: Coal (B) 9: Distillate fuel oil (?)	Cherokee	16.3 16.3 37.5 50 12.5	1988 1988 1950 1954 1964	?
City of McPherson	McPherson 2 GT1: Natural gas (P) GT2: Distillate fuel oil (P) GT3: Natural gas (P)	McPherson	72.4 71.2 71.2	1973 1976 1979	4,946 *0.82*
	McPherson 3 NA1: Natural gas (P)	McPherson	115.6	1998	405 *1.06*
Bowersock	Kansas River Project (1,3-7): Hydro (B)	Douglas	2.6	1922-1925	10,540 *0*

* Standby facility.
** Former Aquila generating facilities. On April 1, 2007, Aquila sold its Kansas electric properties to Mid-Kansas Electric Company (MKEC), a coalition of six consumer-owned cooperatives that also own Sunflower Electric Power Corporation.
*** According to online Sunflower Electric Power Corporation facilities poster (http://www.sunflower.net/pub/Facilities%20Poster2008.pdf)
**** *Included in 2006 EIA 860, but not included in Sunflower's online listing of facilities; possibly renamed as Fort Dodge and Great Bend 3?*

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Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State, 1990-2006

YEAR	STATE	TYPE OF PRODUCER	ENERGY SOURCE	NAMEPLATE CAPACITY (Megawatts)	SUMMER CAPACITY (Megawatts)
2006	KS	Electric Generators, Electric Utilities	All Sources	11,752	10829
2006	KS	Electric Generators, Electric Utilities	Coal	5,472	5203
2006	KS	Electric Generators, Electric Utilities	Hydroelectric	0	0
2006	KS	Electric Generators, Electric Utilities	Natural Gas	4,291	3793
2006	KS	Electric Generators, Electric Utilities	Nuclear	1,236	1166
2006	KS	Electric Generators, Electric Utilities	Other	0	0
2006	KS	Electric Generators, Electric Utilities	Other Gases	0	0
2006	KS	Electric Generators, Electric Utilities	Other Renewables	101	101
2006	KS	Electric Generators, Electric Utilities	Petroleum	652	565
2006	KS	Electric Generators, Electric Utilities	Pumped Storage	0	0

Source: Electric Power Annual 2006 - Data Tables. Energy Information Administration.
http://www.eia.d oe.gov/cneaf/ele ctricity/epa/epa _sprdshts.html. Accessed 2/15/2008.

Example Calculation of Renewable Energy Requirement in 2008 SB 327

Non-renwable nameplate capacity 2006	11,651	Source: Elecric Power Annual 2006
Year 2010	12,267	Projected 2010 nameplate capacity **
	1,227	10% MW nameplate renewable
	1,226,877	KW nameplate renewable
	4,084,027,770	KWh (at 38% capacity factor)
	$ 142,940,972	Total at 3.5 cents per KWh*
Year 2025		
	3,535	25% MW nameplate renewable **
	3,535,452	KW nameplate renewable
	11,768,811,155	KWh (at 38% capacity factor)
	$529,596,502	Total at 4.5 cents per KWh*

* Cost estimates based on Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006, U.S. Department of Energy.

** The total national electricity consumption is projected to grow 1.3% per year (current estimate in Energy Information Administration Annual Energy Outlook 2008). That rate was applied to Kansas 2006 figures for this example.

02/162008

Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State, 1990-2006

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2006	KS	Electric Generators, Electric Utilities	Hydroelectric	0	0
2006	KS	Electric Generators, Electric Utilities	Natural Gas	4,291	3793
2006	KS	Electric Generators, Electric Utilities	Nuclear	1,236	1166
2006	KS	Electric Generators, Electric Utilities	Other	0	0
2006	KS	Electric Generators, Electric Utilities	Other Gases	0	0
2006	KS	Electric Generators, Electric Utilities	Other Renewables	101	101
2006	KS	Electric Generators, Electric Utilities	Petroleum	652	565
2006	KS	Electric Generators, Electric Utilities	Pumped Storage	0	0

Source: Electric Power Annual 2006 - Data Tables. Energy Information Administration.
http://www.eia.d oe.gov/cneaf/ele ctricity/epa/epa _sprdshts.html. Accessed 2/15/2008.

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** The total national electricity consumption is projected to grow 1.3% per year (current estimate in Energy Information Administration Annual Energy Outlook 2008). That rate was applied to Kansas 2006 figures for this example.

Plant	County	Type	Nameplate Capacity (MW)	Net Generation (MWh), Oct. 2006 - Oct. 2007	Tons of CO2 per MWh, October 2006 - October 2007
Holcomb (Sunflower)	Finney	Baseload (combined cycle – coal)/natural gas)	348.7	2,829,430	1.09
Wolf Creek (Westar, KCP&L, KEPCo)	Coffey	Baseload (nuclear)	1235.7	10,071,556	0.00
Gordon Evans Energy Center 1 (KG&E)	Sedgwick	Peaking	904	543,319	0.09
La Cygne 1 (KCP&L)	Linn	Baseload (coal)	1578	10,296,491	1.07
Murray Gill (1 – 4) (KG&E)	Sedgwick	Peaking (natural gas)	349	147,453	0.79
Hutchinson Energy Center (Westar)	Reno	Peaking (natural gas)	554.7	134,869	0.71
Lawrence Energy Center (3 – 5) (Westar)	Douglas	Baseload (combined cycle – coal)/natural gas)	566	3,507,588	1.18
Tecumseh Energy Center (1 – 2) (Westar)	Shawnee	Peaking (natural gas)	58	0	na
Tecumseh Energy Center (7 – 8) (Westar)	Shawnee	Baseload (coal, natural gas)	232	1,431,798	1.22
Quindaro (GT1 – GT3) (KCBPU)	Wyandotte	Baseload (distillate fuel oil/natural gas)	149.3	2,560	1.83
Quindaro (ST1 – ST2) (KCBPU)	Wyandotte	Baseload (combined cycle – coal)/natural gas)	239.1	1,162,098	1.14
McPherson (2) (City of Mcpherson)	McPherson	Peaking (natural gas)	214.8	4,946	0.82
McPherson (3) (City of Mcpherson)	McPherson	Peaking (distillate fuel oil)	115.6	405	1.06
Garden City (Sunflower)	Finney	Intermediate (natural gas)	267.8	48,757	0.77
Nearman Creek (1) (KCBPU)	KCBPU	Baseload (coal)	261	1,597,931	1.18
Nearman Creek (CT4) (KCBPU)	KCBPU	Peaking (natural gas)	94	29,812	0.75
Jeffrey Energy Center (1 – 3) (Westar)	Pottawatomie	Baseload (coal)	2160	15,202,432	1.16
Osawatomie (KCP&L)	Miami	Peaking	90	9,172	0.81
West Gardner (KCP&L)	Johnson	Intermediate	365.2	99,552	0.78
Kansas River Project (Bowersock)	Douglas	Baseload	2.6	10,540	0.00
Neosho (KG&E)	Labette	Peaking	98.8		
Abilene Energy Center (Westar)	Dickinson	Peaking	77		
Fort Dodge 4 (Sunflower)	Ford	Load Following	145		
Cimarron River 1 (Sunflower)	Seward	Intermediate/Co-gen	61		
Cimarron River 2 (Sunflower)	Seward	Peaking	15		
GC-3 (Sunflower)		Intermediate	9		
Great Bend 3 (Sunflower)	Barton	Intermediate	98		
Clifton-1 (Sunflower)		Peaking	73		
S-5 (Sunflower)		Peaking	53		
S-4 (Sunflower)		Peaking	51		
S-3 (Sunflower)		Peaking	14		
S-2 (Sunflower)		Intermediate	98		

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Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

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The U.S. Department of Energy (DOE) estimates that in the coming decades the United States' natural gas (NG) demand for electricity generation will increase. Estimates also suggest that NG supply will increasingly come from imported liquefied natural gas (LNG). Additional supplies of NG could come domestically from the production of synthetic natural gas (SNG) via coal gasification–methanation. The objective of this study is to compare greenhouse gas (GHG), SO_x, and NO_x life-cycle emissions of electricity generated with NG/LNG/SNG and coal. This life-cycle comparison of air emissions from different fuels can help us better understand the advantages and disadvantages of using coal versus globally sourced NG for electricity generation. Our estimates suggest that with the current fleet of power plants, a mix of domestic NG, LNG, and SNG would have lower GHG emissions than coal. If advanced technologies with carbon capture and sequestration (CCS) are used, however, coal and a mix of domestic NG, LNG, and SNG would have very similar life-cycle GHG emissions. For SO_x and NO_x we find there are significant emissions in the upstream stages of the NG/LNG life-cycles, which contribute to a larger range in SO_x and NO_x emissions for NG/LNG than for coal and SNG.

1. Introduction

Natural gas currently provides 24% of the energy used by United States homes (*1*). It is an important feedstock for the chemical and fertilizer industry. Low wellhead gas prices (less than \$3/thousand cubic feet (Mcf) (*2*)) spurred a surge in construction of natural-gas-fired power plants: between 1992 and 2003, while coal-fired capacity increased only from 309 to 313 GW, natural-gas-fired capacity more than tripled, from 60 to 208 GW (*3*). Adding to this was the Energy Information Agency's (EIA) prediction of continued low natural gas prices (around \$4/Mcf) through 2020 (*4*), lower capital costs, shorter construction times, and generally lower air emissions for natural-gas-fired plants that allowed power generators to meet the clean air standards (*5*). However, instead of remaining near projected levels, the average wellhead price of natural gas peaked at \$11/Mcf in October 2005 (*6*). This price increase made natural gas uneconomical as a feedstock, so most natural-gas-fired plants are operating below capacity (*7*). Despite these trends, natural gas consumption is expected to increase by 20% of 2003 levels by 2030. Demand from electricity generators is projected to grow the fastest. At the same time, natural gas production in the United States and pipeline imports from Canada and Mexico are expected to remain fairly constant (*8*). The gap between North American supply and U.S. demand can only be met with alternative sources of natural gas, such as imported liquefied natural gas (LNG) or synthetic natural gas (SNG) produced from coal. Current projections by EIA estimate that LNG imports will increase to 16% of the total U.S. natural gas supply by 2030 (*8*). Alternatively, Rosenberg et al. call for congress to promote gasification technologies that use coal to produce SNG. This National Gasification Strategy calls for the United States to produce 1.5 trillion cubic feet (tcf) of synthetic natural gas per year within the next 10 years (*7*), equivalent to 5% of expected 2030 demand.

The natural gas system is one of the largest sources of greenhouse gas emissions in the United States, generating around 132 million tons of CO_2 equivalents annually (*1*). Significant emissions of criteria air pollutants also come from upstream combustion life-cycle stages of the gas. Emissions from the emerging LNG life-cycle stages or from the production of SNG have not been studied in detail. If larger percentages of the U.S. supply of natural gas will come from these alternative sources, then LNG or SNG supply chain emissions become an important part of understanding overall natural gas life-cycle emissions. Also, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform a life-cycle analysis (*9, 10*) of natural gas, LNG, and SNG. Direct air emissions from the processes during the life-cycle will be considered, as well as air emissions from the combustion of fuels and electricity used to run the process. A comparison with coal life-cycle air emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

2. Fuel Life-Cycles

The natural gas life-cycle starts with the production of natural gas and ends at the combustion plant. Natural gas is extracted from wells and sent to processing plants where water, carbon dioxide, sulfur, and other hydrocarbons are removed. The produced natural gas then enters the transmission system. The U.S. transmission system also includes some storage of natural gas in underground facilities such as reconditioned depleted gas reservoirs, aquifers, or salt caverns to meet seasonal and/or sudden short-term demand. From the transmission and storage system, some natural gas goes directly to large-scale consumers, like electric power generators, which is modeled here. The rest goes into local distribution systems that deliver it to residential and commercial consumers via low-pressure, small-diameter pipelines.

The use of liquefied natural gas (LNG) adds three additional life-cycle stages to the natural gas life-cycle described above. Natural gas is produced and processed to remove contaminants and transported by pipeline relatively short distances to be liquefied. In the liquefaction process, natural gas is cooled and pressurized (*11*). Liquefaction plants are generally located in coastal areas of LNG exporting countries and dedicated LNG ocean tankers transport LNG

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to the United States. Upon arriving, the LNG tankers offload their cargo and the LNG is regasified. At this point the regasified LNG enters the U.S. natural gas transmission system.

The coal life-cycle is conceptually simpler than the natural gas life-cycle, consisting of three major steps: coal mining and processing, transportation, and use/combustion.

U.S. coal is produced from surface mines (67%), or underground mines (33%) (*1*). Mined coal is processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (*12*). More than 90% of the coal used in the United States is used by the electric power sector, which is modeled here (*8*).

The life-cycle of SNG is a combination of some stages from the coal life-cycle and some stages of the natural gas life-cycle. Coal is mined, processed, and transported, as in the coal life-cycle, to the SNG production plant. At this plant, syngas, a mixture of carbon monoxide (CO) and hydrogen (H_2), is produced by gasification and converted, via methanation, to methane and water. The SNG is then sent to the natural gas transmission system, described above, and on to the electric power generator.

3. Methods for Calculating Life-Cycle Air Emissions

In our study we investigate the life-cycle air emissions from coal, natural gas, LNG, and SNG use. All fossil fuel options are used to produce electricity and combustion emissions are included as a component of the each life-cycle. For GHG, the emissions factors at power plants used are 120 lb CO_2 equiv/MMBtu of natural gas and 205 lb CO_2 equiv/MMBtu of coal. The SO_x and NO_x emissions at power plants are presented in the results section and in the Supporting Information

3.1. Life-Cycle Air Emissions from Natural Gas produced in North America. In 2003, the total consumption of natural gas in the United States was over 27 trillion cubic feet (tcf). Of this, 26.5 tcf were produced in North America (U.S., Canada, and Mexico) (*13*). According to the Environmental Protection Agency (EPA), 1.07% of the natural gas produced is lost in its production, processing, transmission, and storage (*14*). Total methane emissions were calculated using the percentage of natural gas lost. It was also assumed that natural gas has an average heat content of 1030 Btu/ft^3 (*13*), and that 96% of the natural gas lost is methane, which has a density of 0.0424 lb/ ft^3 (*14*).

In 1993 the U.S. EPA established the Natural Gas STAR program to reduce methane emissions from the natural gas industry. Data from this program for the reductions in methane lost in the natural gas system, as described in the Supporting Information, were combined with the data described above to develop a range of methane emissions factors for the North American natural gas life-cycle stages.

Carbon dioxide emissions are produced from the combustion of natural gas used during various life-cycle stages and from the production of electricity consumed during transport. EIA provides annual estimates of the amount of natural gas used for the production, processing, and transport of natural gas. In 2003, approximately 1900 billion cubic feet of natural gas were consumed during these stages of the natural gas life-cycle (*13*). Total carbon dioxide emissions were calculated using a carbon content in natural gas of 31.90 lb C/MMBtu and an oxidation fraction of 0.995 (*1*). According to the Transportation Energy Data Book, 3 billion kWh were used for natural gas pipeline transport in 2003 (*15*). The average GHG emission factor from the generation of this electricity is 1400 lb CO_2 equiv/MWh (*16*). These CO_2 emissions were added to methane emissions to obtain the upstream combustion GHG emission factors for North American natural gas.

SO_x and NO_x emissions from the natural gas upstream stages of the life-cycle come from the combustion of the fuels used to produce the energy that runs the system, as given in the Supporting Information. Total emissions from flared gas were calculated using the AP 42 Emission Factors for natural gas boilers (*17*). A range of emissions from the combustion of the natural gas used during the upstream stages of the life-cycle was developed using the AP 42 Emissions Factors for reciprocating engines and for natural gas turbines (*17*). Emissions from generating the electricity used during natural gas pipeline operations were estimated using the most current average emission factors given by EGRID: 6.04 lb SO_2/MWh and 2.96 lb NO_x/MWh (*16*). Note that EGRID reports emissions of SO_2 only. Other references used in this paper report total SO_x emission. For this paper, sulfur emission will be reported in terms of SO_x emissions.

In addition to emissions from the energy used during the life-cycle of natural gas, SO_x emissions are produced in the processing stage of the life-cycle, when hydrogen sulfide (H_2S) is removed from the sour natural gas to meet pipeline requirements. A range of SO_x emissions from this processing of natural gas was developed using the AP 42 emissions factors for natural gas processing and for sulfur recovery (*17*). To use the AP 42 emission factors for sulfur recovery, we found that in 2003 1945 thousand tons of sulfur were recovered from 14.7 trillion cubic feet of natural gas resulting in a calculated average natural gas H_2S mole percentage of 0.0226. This was then used with the AP 42 emission factors for natural gas processing.

3.2. Air Emissions from the LNG Life-Cycle. In 2003, 500 billion cubic feet of natural gas were imported in the form of LNG (*13*). In 2003, 75% of the LNG imported to the United States came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (*13*). According to EIA, the LNG tanker world fleet capacity should have reached 890 million cubic feet of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (*18*). There are currently 5 LNG terminals in operation in the United States, with a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved by the Federal Energy Regulatory Commission (FERC) (*19*).

Due to unavailability of data for emissions from natural gas production in other countries, it is assumed that natural gas imported to the United States in the form of LNG produces the same emissions from the production and processing life-cycle stages as North American natural gas. Those stages are incorporated for LNG. Most of the natural gas converted to LNG is produced from modern fields developed and operated by multinational oil and gas companies, so they are assumed to be operated in a similar way to those in the United States.

It is expected that transportation of natural gas from the production field to the liquefaction plant would have emissions similar to those of pipeline transport of domestic natural gas. But the emission factor for the U.S. system (which is included in the LNG life-cycle) is based on total pipeline distances of over 200 000 miles (*20*). Because LNG facilities are closely paired with gas fields, it is expected that the average distance from production field to a LNG facility would be much smaller than 200 000 miles. Also, because there were no reliable data for the myriad of fields and facilities and suspected impact on the overall life cycle would be minimal, this transport from the fields to the liquefaction terminals was ignored. This would slightly underestimate the emissions from the LNG life cycle.

Additional emission factors were developed for the liquefaction, transport, and regasification life-cycle stages of LNG. Tamura et al. have reported emission factors for the

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liquefaction stage in the range of 11−31 lb CO_2 equiv/MMBtu (*21*). The sources of these emissions are outlined in the Supporting Information.

LNG is shipped to the United States via LNG tankers. LNG tankers are the last ship type to use steam turbine technology in their engines. This technology allows for easy use of boil-off gas (BOG) in a gas boiler. Boil-off rates in LNG tankers range between 0.15% and 0.25% per day when loaded (*22, 23*). When there is not enough BOG available, a fuel oil boiler is used to produce the steam. In addition to this benefit, steam turbines require less maintenance than diesel engines, which is beneficial to these tankers that have to be readily available to leave a terminal in case of emergency (*22*).

Most LNG tankers currently in operation have a capacity to carry between 4.2 and 5.3 million cubic feet of LNG (2.6 and 3.2 billion cubic feet of gas). There are smaller tankers available, but they are not widely used for transoceanic transport. There is also discussion about building larger tankers (8.8 million cubic feet), however none of the current U.S. terminals can handle tankers of this size (*18*).

The rated power of the LNG tankers ranges between 20 and 30 MW, and they operate under this capacity around 75% of the time during a trip (*24, 25*). The energy required to power this engine is 11.6 MMBtu/MWh (*26*). As previously mentioned, some of this energy is provided by BOG and the rest is provided by fuel oil. A loaded tanker with a rated power of 20 MW, and 0.12% daily boil-off rate would consume 3.88 million cubic feet of gas per day and 4.4 tons of fuel oil per day. The same tanker would consume 115 tons of fuel oil per day on they way back to the exporting country operating under ballast conditions. A loaded tanker with a rated power of 30 MW, and a 0.25% daily boil-off rate would get all its energy from the BOG, with some excess gas being combusted to reduce risks of explosion (*22*). Under ballast conditions, the same tanker would consume 172 tons of fuel oil per day.

For LNG imported in 2003 the average travel distance to the Everett, MA LNG terminal was 2700 nautical miles (*13, 27*). In the future LNG could travel as far as far as 11 700 nautical miles (the distance between Australia and the Lake Charles, LA LNG terminal (*27*)). This range of distances is representative of distances from LNG countries to U.S. terminals that could be located on either the East or West coasts. To estimate the number of days LNG would travel (at a tanker speed of 20 knots (*22*)), these distances were used. This trip length can then be multiplied by the fuel consumption of the tanker to estimate total trip fuel consumption and emissions, and these can then be divided by the average tanker capacity to obtain a range of emission factors for LNG tanker transport between 2 and 17 lb CO_2 equiv/MMBtu.

Regasification emissions were reported by Tamura et al. to be 0.85 lb CO_2 equiv/MMBtu (*21*). Ruether et al. report an emission factor of 3.75 lb of CO_2 equiv/MMBtu for this stage of the LNG life-cycle by assuming that 3% of the gas is used to run the regasification equipment (*28*). The emission reported by Tamura et al. differs because they assumed only 0.15% of the gas is used to run the regasification terminal, while electricity, which may be generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG.

As done for the carbon emissions, natural gas produced in other countries and imported to the United States in the form of LNG is assumed to have the same SO_x and NO_x emissions in the production, processing, and transmission stages of the life-cycle as for natural gas produced in North America. Emission ranges for the liquefaction and regasification of natural gas were calculated using the AP 42 emission factors for reciprocating engines and natural gas turbines (*17*). It is assumed that 8.8% of natural gas is used in the liquefaction plant (*21*) and 3% is used in the regasification plants (*28*). Emissions of SO_x, and NO_x from transporting the LNG via tanker were calculated using the AP 42 emission factor for natural gas boilers and diesel boilers, as well as the tanker fuel consumption previously described.

3.3. Air Emissions from the Coal Life-Cycle. Greenhouse gas emissions from the mining life-cycle stage were developed from methane releases and from combustion of fuels used at the mines. EPA estimates that methane emissions from coal mines in 1997 were 75 million tons of CO_2 equivalents, of which 63 million tons came from underground mines and 12 million tons came from surface mines (*1*). CO_2 is also emitted from mines through the combustion of the fuels that provide the energy for operation. The U.S. Census Bureau provides fuel consumption data for mines in 1997 (*29*). These data are available in the Supporting Information. Fuel consumption data were converted to GHG emissions using the carbon content and heat content of each fuel and an oxidation fraction given in EPA's Inventory of U.S. Greenhouse Gas Emissions Sources and Sinks (*1*) (see Supporting Information). Emissions from the generation of the electricity consumed were calculated using an average 1997 emission factor of 1400 lb CO_2 equiv/MWh (*16*). These total emissions were then converted to an emission factor using the amount of coal produced in 1997 and the average heat content of this coal.

Emissions from the transportation of coal were calculated using the EIO-LCA tool developed at Carnegie Mellon University (*30*). To use this tool, economic values for coal transportation were needed. In 1997, the latest year for which the EIO-LCA tool has data, 84% of coal was transported via rail, 11% via barge, and 5% via truck. The cost for rail transport, barge, and truck transport was 13.9, 9.5, and 142.7 mills/ton-mile respectively (*12*). For a million ton-miles of coal transported, EIO-LCA estimates that 43.6 tons of CO_2 equivalents are emitted from rail transportation, 5.89 tons of CO_2 equivalents from water transportation, and 69 tons of CO_2 equivalents from truck transportation (*30*). These emissions were then converted to an emission factor by using the average travel distance of coal in each mode (796, 337, and 38 miles by rail, barge, and truck, respectively), the weighted average U.S. coal heat content of 10 520 Btu/lb (*31*) and the coal production data for 1997 (see Supporting Information).

The energy consumption data used to develop carbon emissions from the mining life-cycle stage were used to develop SO_x and NO_x emission factors for coal. AP 42 emissions factors for off-road vehicles, natural gas turbines, reciprocating engines, light duty gasoline trucks, large stationary diesel engines, and gasoline engines were used to develop this range of emission factors (*17, 32*). In addition, the average emission factors from electricity generation in 1997 (3.92 lb NO_x/MWh and 7.86 lb SO_2/MWh (*16*)) were used to include the emissions from the electricity used in mines.

SO_x and NO_x emissions for coal transportation were again calculated using EIO-LCA (*30*). EIO-LCA estimates that a million ton-miles of coal transported via rail results in emissions of 0.02 tons of SO_x and 0.4 tons of NO_x. A million ton-miles of coal transported via water would emit 0.07 tons of SO_x, and 0.36 tons of NO_x. Finally, a million ton-miles of coal transported via truck would emit 0.06 tons of SO_x, and 1.42 tons of NO_x (*30*). These data were added to emissions from mines to find the total SO_x and NO_x emission factors for the upstream stages of the coal life-cycle.

3.4. Air Emissions from the SNG Life-Cycle. Performance characteristics for two SNG plants are given in the Supporting Information. These plants have a higher heating value efficiency between 57% and 60% (*33, 34*). Using these efficiencies, emissions from coal mining, processing, and

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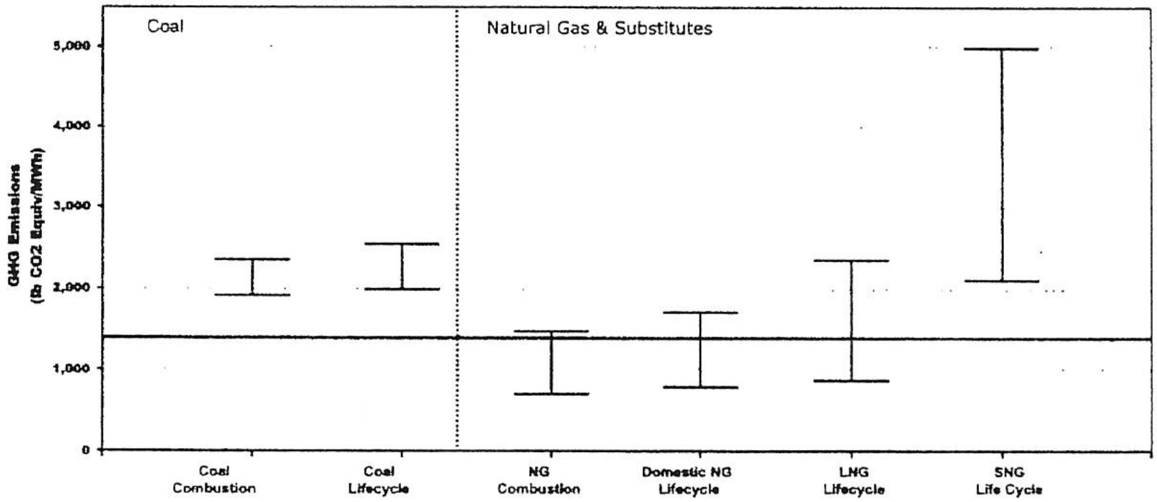

FIGURE 1. Fuel Combustion and Life-Cycle GHG Emissions for Current Power Plants.

transportation previously obtained were converted to pounds of CO_2 equiv/MMBtu of SNG. The data were also used to calculate the emissions at the gasification–methanation plant using a coal carbon content of 0.029 tons/MMBtu and a calculated SNG storage fraction of 37% (*1*). Finally, the emissions from transmission, storage, distribution, and combustion of SNG are the same as those for all other natural gas.

To develop the SO_x and NO_x emissions from the life-cycle of SNG, the emissions from coal mining and transport developed in the previous section in pounds per MMBtu of coal were converted to pounds per MMBtu of SNG using the efficiencies previously discussed. In addition, the emissions from natural gas transmission and storage were assumed to represent emissions from these life-cycle stages of SNG. The emissions from the gasification–methanation plant were taken from emission data for an Integrated Coal Gasification Combine Cycle (IGCC) plant, which operates with a similar process. Bergerson (*35*) reports SO_x emissions factors from IGCC between 0.023 and 0.15 lb/MMBtu coal (0.026–0.17 lb/MMBtu of coal if there is carbon capture), and a NO_x emission factor of 0.0226 lb/MMBtu coal (0.0228 lb/MMBtu of coal if there is carbon capture). These were converted to lb/MMBtu of SNG using the same coal-to-SNG efficiencies previously described.

4. Results

4.1. Comparing Fuel Life-Cycle Emissions for Fuels Used at Currently Operating Power Plants. Emission factors for the fuel life-cycles were calculated as pounds of pollutants per MMBtu of fuel produced, as presented in the Supporting Information. Since coal and natural gas power plants have different efficiencies, 1 MMBtu of coal does not generate the same amount of electricity as 1 MMBtu of natural gas/LNG/SNG. For this reason, emission factors given in Table 10S and Table 11S in the Supporting Information were converted to pounds of pollutant per MWh of electricity generated. This conversion is done using the efficiency of natural gas and coal power plants. According to the U.S. Department of Energy (DOE), currently operating coal power plants have efficiencies ranging from 30% to 37%, while currently operating natural gas power plants have efficiencies ranging from 28% to 58% (*36*). The life-cycle GHG emissions factors of natural gas, LNG, coal, and SNG described in the Supporting Information were converted to a lower and upper bound emission factor from coal and natural gas power plants using these efficiency ranges. Figure 1 shows the final bounds for the emission factors for each fuel cycle. The life-cycle for each fuel use includes fuel combustion at a power plant. The combustion-only emissions for each fuel are shown for comparison. The solid horizontal line shown represents the current average GHG emission factor for U.S. electricity generation: 1400 lb CO_2 equiv/MWh (*16*). Note that in this graph no carbon capture and storage (CCS) is performed at any stage of the life-cycle. CCS is a process by which carbon emissions are separated from other combustion products and injected into underground geologic formations such as saline formations or depleted oil/gas fields. A scenario in which CCS is performed at power plants as well as in gasification–methanation plants will be discussed in the following section.

It can be seen that combustion emissions from coal-fired power plants are higher than those from natural gas: the midpoint between the lower and upper bound emission factors for coal combustion is approximately 2100 lb CO_2 equiv/MWh, while the midpoint for natural gas combustions is approximately 1100 lb CO_2 equiv/MWh. This reflects the known environmental advantages from combustion of natural gas over coal. Figure 1 also shows that the life-cycle GHG emissions of electricity generated with coal are dominated by combustion, and adding the upstream life-cycle stages does not change the emission factor significantly, with the midpoint between the lower and upper bound life-cycle emission factors being 2270 lb CO_2 equiv/MWh. For natural-gas-fired power plants the emissions from the upstream stages of the natural gas life-cycle are more significant, especially if the natural gas used is synthetically produced from coal (SNG). The midpoint life-cycle emission factor for domestic natural gas is 1250 lb CO_2 equiv/MWh; for LNG and SNG it is 1600 lb CO_2 equiv/MWh and 3550 lb CO_2 equiv/MWh, respectively. SNG has much higher emission factors than the other fuels because of efficiency losses throughout the system. It is also interesting to note that the range of life-cycle GHG emissions of electricity generated with LNG is significantly closer to the range of emissions from coal than the life-cycle emissions of natural gas produced in North America. The upper bound life-cycle emission factor for LNG is 2400 lb CO_2 equiv/MWh, while the upper bound life-cycle emission factor for coal is 2550 lb CO_2 equiv/MWh.

To compare emissions of SO_x and NO_x from all life-cycles, the upstream emission factors and the power plant efficiencies from the Supporting Information are used. Emissions of these pollutants from coal and natural gas power plants in operation in 2003 were obtained from EGRID (*37*). Table 1

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TABLE 1. SO_x and NO_x Combustion and Life-Cycle Emission Factors for Current Power Plants

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	combustion	1.54	25.5	2.56	9.08
	life-cycle	1.60	25.8	2.83	9.69
natural gas	combustion	0.00	1.13	0.12	5.20
	life-cycle	0.04	1.49	0.17	9.40
LNG	life-cycle	0.094	2.93	0.25	15.4
SNG	life-cycle	0.30	3.88	0.65	8.08

shows life-cycle emissions for each fuel obtained by adding the combustion emissions from EGRID to the transformed upstream emissions. The current average SO_x and NO_x emission factors for electricity generated in the United States are also shown (*16*).

It can be seen that coal has significantly larger SO_x emissions than natural gas, LNG, or SNG. This is expected since the sulfur content of coal is much higher than the sulfur content of other fuels. SNG, which is produced from coal, does not have high sulfur emissions because the sulfur from coal must be removed before the methanation process.

For NO_x, it can be seen that the upstream stages of domestic natural gas, LNG, and even SNG make a significant contribution to the total life-cycle emissions. These upstream NO_x emissions come from the combustion of fuels used to run the natural gas system: for domestic natural gas, production is the largest contributor to these emissions; for LNG most NO_x upstream emissions come from the liquefaction plant; finally, for SNG most upstream NO_x emissions come from the gasification−methanation plant.

4.2. Comparing Fuel Life-Cycle Emissions for Fuels Used with Advanced Technologies. According to the DOE, by 2025 65 GW of inefficient facilities will be retired, while 347 GW of new capacity will be installed (*8*). Advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) power plants could be installed. PC, IGCC, and NGCC plants are generally more efficient (average efficiencies of 39%, 38%, and 50%, respectively (*38*)) than the current fleet of power plants. In addition, CCS could be performed with these newer technologies. Experts believe that sequestration of 90% of the carbon will be technologically and economically feasible in the next 20 years (*5, 38*). Having CCS at PC, IGCC, and NGCC plants decreases the efficiency of the plants to average of 30%, 33%, and 43%, respectively (*38*).

Figure 2 was developed using the revised efficiencies for advanced technologies and the GHG emission factors (in lb/MMBtu) described in the Supporting Information. This figure represents total life-cycle emissions for electricity generated with each fuel. Notice that emissions are shown with and without CCS. In the case of SNG with CCS, capture is performed at both the gasification−methanation plant and at the power plant. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the United States (1400 lb CO_2 equiv/MWh) (*16*). The upper and lower bound emissions in this figure are closer together than the upper and lower bounds in Figure 1, because only one power plant efficiency value is used, while for Figure 1 the upper and lower bound efficiency from all currently operating power plants was used (this is especially obvious for the domestic natural gas (NGCC) cases). It can be seen that, in general, life-cycle GHG emissions of electricity generated with the fuels without CCS would decrease slightly compared to emissions from current power plants that use the same fuel (due to efficiency gains). The most efficient natural gas plant currently in operation, however, could have slightly lower emissions than the lower bound for NGCC, LNGG, and SNGCC, due to efficiency differences. Three of the cases, however (PC, IGCC, and SNGCC), would still have higher emissions than the current average emissions from power plants. If CCS were used, however, there would be a significant reduction in emissions for all cases. In addition the midpoints between upper and lower bound emissions from all fuels are closer together, as can be seen in Figure 3. This figure also shows how the upstream from combustion emissions of fuels become significant contributors to the life-cycle emission factors when CCS is used.

Table 2 was developed using the upstream SO_x and NO_x emission factors obtained in this study and the combustion emissions reported by Bergerson (*35*) for PC and IGCC plants and by Rubin et al. for NGCC plants (*38*). These reported combustion emissions can be seen in the Table 12S in the Supporting Information.

As can be seen from Table 2, if advanced technologies are used there could be a significant reduction of NO_x and SO_x emissions, even if CCS is not available. It is interesting also to note that a PC plant with CCS could have lower life-cycle emissions than an IGCC plant with CCS. In the PC case all sulfur is removed through flue gas desulfurization. The removed sulfur compounds are then solidified and disposed of or sold as gypsum. In an IGCC plant with CCS, sulfur is removed from the syngas before combustion. In these plants, however, instead of solidifying the sulfur compounds removed and disposing them, the elemental sulfur is recovered in a process that generates some additional SO_x emissions (*35*). For NO_x, only LNG has higher life-cycle emissions than the average generated at current power plants.

5. Discussion

Natural gas is an important energy source for the residential, commercial, and industrial sectors. In the 1990s, the surge in demand by electricity generators and relatively constant natural gas production in North America caused prices to increase, so that in 2005 these sectors paid 58 billion dollars more than they would have paid if 2000 prices remained constant. Cumulative additional costs of higher natural gas prices for residential, commercial, and industrial consumers between 2000 and 2005 were calculated to be around 120 billion dollars. LNG has been identified as a source of natural gas that might help reduce prices, but even with an increasing supply of LNG, EIA still projects average delivered natural gas prices above $6.5/Mcf in the next 25 years. This is higher than the $4.5 /Mcf average projected price in earlier reports before the natural-gas-fired plant construction boom (*4*).

In addition to LNG, SNG has been proposed as an alternative source to add to the natural gas mix. The decision to follow the path of increased LNG imports or SNG production should be examined in light of more than just economic considerations. In this paper, we analyzed the effects of the additional air emissions from the LNG/SNG life-cycle on the overall emissions from electricity generation in the United States. We found that with current electricity generation technologies, natural gas life-cycle GHG emissions are generally lower than coal life-cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG emissions from coal and natural gas. SNG has higher life-cycle GHG emission than coal, domestic natural gas, or LNG. It is also important to note that upstream GHG emissions of NG/LNG/SNG have a higher impact in the total life-cycle emissions than upstream coal emissions. This is a significant point when considering a carbon-constrained future in which combustion emissions are reduced.

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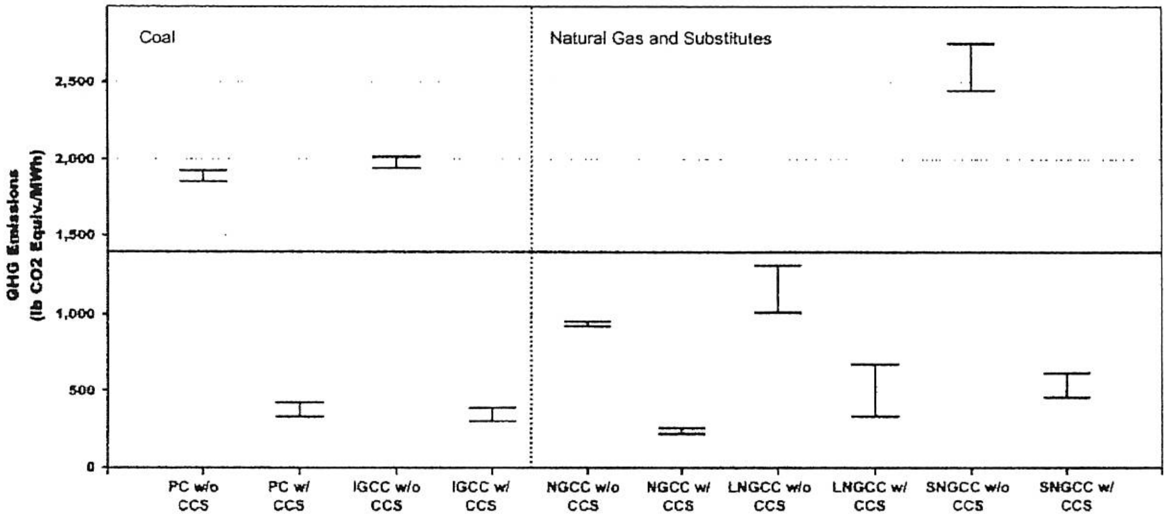

FIGURE 2. Fuel GHG Life-Cycle Emissions Using Advanced Technologies.

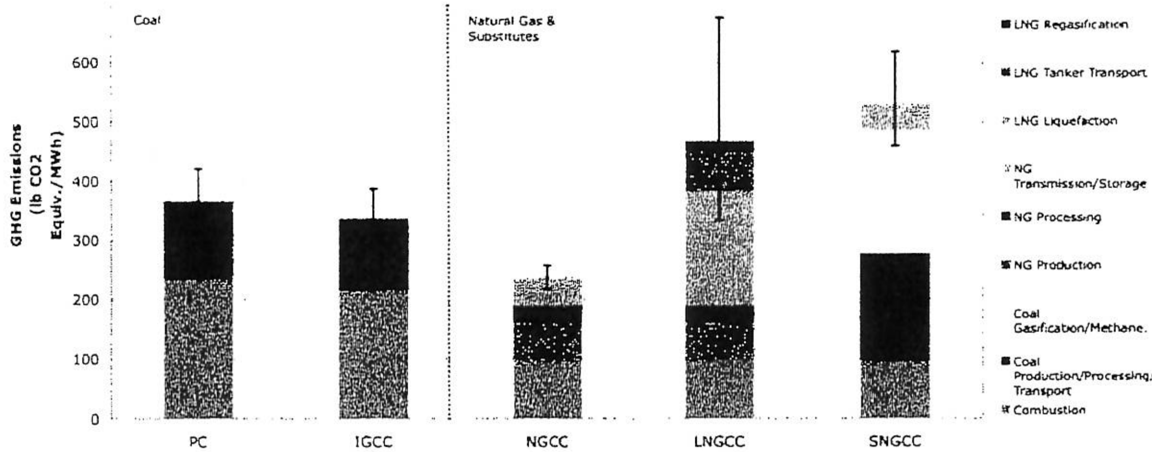

FIGURE 3. Midpoint Life-Cycle GHG Emissions Using Advanced Technologies with CCS.

TABLE 2. SO_x and NO_x Life-Cycle Emission Factors for Advanced Technologies

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	PC w/o CCS	0.24	1.54	1.42	2.46
	PC w/ CCS	0.08	0.34	1.90	3.61
	IGCC w/o CCS	0.27	1.57	0.47	0.70
	IGCC w/ CCS	0.32	1.83	0.54	0.78
natural gas	NGCC w/o CCS	0.04	0.20	0.30	2.57
	NGCC w/ CCS	0.05	0.24	0.36	3.01
LNG	NGCC w/o CCS	0.25	1.04	0.39	5.89
	NGCC w/ CCS	0.30	1.23	0.46	6.91
SNG	NGCC w/o CCS	0.35	2.15	0.88	1.85
	NGCC w/ CCS	0.45	2.80	1.03	2.18

For emissions of SO_x, we found that with current electricity generation technologies, coal has significantly higher life-cycle emissions than any other fuel due to very high emissions at current power plants. For NO_x, however, this pattern is different. We find that with current electricity generation technologies, LNG could have the highest life-cycle NO_x emissions (since emissions from liquefaction and regasification are significant), and that even natural gas produced in North America could have life-cycle NO_x emissions very similar to those of coal. It is important to note that while GHG emissions contribute to a global problem, SO_x and NO_x are local pollutants and U.S. policy makers may not give much weight to emissions of these pollutants in other countries.

In the future, as newer generation technologies and CCS are installed, the overall life-cycle GHG emissions from electricity generated with coal, domestic natural gas, LNG, or SNG could be similar. Most important is that all fuels with advanced combustion technologies and CCS have lower life-cycle GHG emission factors than the current average emission factor from electricity generation. For SO_x we found that coal and SNG would have the largest life-cycle emissions, but all fuels have lower life-cycle SO_x emissions than the current average emissions from electricity generation. For NO_x, LNG would have the highest life-cycle emissions and would be the only fuel that could have higher emissions than the current average emission factor from electricity generation, even with advanced power plant design.

We suggest that advanced technologies are important and should be taken into account when examining the possibility of doing major investments in LNG or SNG infrastructure. Power generators hope that the price of natural gas will decrease as alternative sources of natural gas are added to the U.S. mix, so they can recover the investment made in

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natural gas plants that are currently producing well under capacity. We suggest that these investments should be viewed as sunk costs. Thus, it is important to re-evaluate whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected and increase the environmental burden from our energy infrastructure.

Acknowledgments

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Supporting Information Available

Graphical representation of the fuel life-cycles, emissions calculation information, summary of emissions from fuel life-cycles, power plant efficiency information, emissions from advanced technologies, and references, This material is available free of charge via the Internet at http://pubs.acs.org.

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