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LBNL-6025E

Projections of Full-Fuel-Cycle Energy and Emissions Metrics

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January 2013

This work was supported by the Director, Office of Science, Office of Basic Energy Sciences, of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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January 23, 2013

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Abstract

To accurately represent how conservation and efficiency policies affect energy demand, both direct and indirect impacts need to be included in the accounting. The indirect impacts are defined here as the resource savings that accrue over the fuel production chain, which when added to the energy consumed at the point of use, constitute the *full-fuel- cycle* (FFC) energy. This paper uses the accounting framework developed in (Coughlin 2012) to calculate FFC energy metrics as time series for the period 2010-2040. The approach is extended to define FFC metrics for the emissions of greenhouse gases (GHGs) and other air-borne pollutants. The primary focus is the types of energy used in buildings and industrial processes, mainly natural gas and electricity. The analysis includes a discussion of the fuel production chain for coal, which is used extensively for electric power generation, and for diesel and fuel oil, which are used in mining, oil and gas operations, and fuel distribution. Estimates of the energy intensity parameters make use of data and projections from the Energy Information Agency's National Energy Modeling System, with calculations based on information from the *Annual Energy Outlook 2012*.

1. Introduction

To accurately represent how conservation and efficiency policies affect energy demand, both direct and indirect impacts need to be included in the accounting. The indirect impacts are defined here as the resource savings that accrue over the fuel production chain, from extraction to delivery to the point-of-use, in response to a reduction in energy demand elsewhere in the economy. This segregation of the economy into the fuel production sector and "everything else", combined with separate accounting for the use of energy in fuel production, is referred to as full-fuel- cycle (FFC) analysis. FFC analysis relies on a detailed inventory of the energy use and the material losses at each stage of fuel production, as well as forecasts of these and other variables related to energy supply. Often the available data do not provide sufficient detail, and numerous assumptions must be made to arrive at quantitative results. The problem can be simplified by separating the definition of the fuel-cycle accounting methodology from issues related to obtaining the required input data. A clearer view of the mathematical interdependence of the physical variables can facilitate the construction of scenarios to quantify uncertainty, help to resolve any discrepancies that may appear between different methodologies, and identify priorities for future research.

This paper uses the accounting framework developed in (Coughlin 2012) to calculate FFC energy metrics as time series for the period 2010-2040. The approach is also extended here to define FFC metrics for the emissions of greenhouse gases (GHGs) and other air-borne pollutants.[1] This methodology defines mathematical formulae for a number of different fuel-cycle metrics as a function of a set of physical parameters representing the energy intensity of fuel production organized by fuel type. Our primary focus is the types of energy used in buildings and industrial processes, natural gas and electricity. The analysis includes a discussion of the fuel production chain for coal, which is used extensively for electric power generation, and for diesel and fuel oil, which are used in mining, oil and gas operations, and fuel distribution. In

[1] The greenhouse gases are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O); other pollutants are nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury (Hg).

this context petroleum-based fuels are relatively unimportant (compared for example to transportation energy use) and are not treated in great detail. The accounting methods used to estimate the energy intensity parameters make use of data and projections from the Energy Information Agency's (EIA's) National Energy Modeling System (NEMS) (DOE EIA 2012a). Calculations presented here are based on information from the *Annual Energy Outlook 2012* (*AEO 2012*) (DOE EIA 2012b).

Energy that is consumed directly to provide a service, such as burning natural gas to provide heat, or using electricity to run a motor, is referred to here as site fuel or site energy consumption. To provide a unit of site energy, some energy must be consumed by various activities along the fuel production chain; this energy is referred to as upstream energy. If the site energy demand is reduced by one unit, the economy-wide demand for energy will be reduced by an additional amount corresponding to the upstream fuel use. The sum of site energy and upstream energy is equal to the full-fuel-cycle energy. When all quantities are normalized to the same units, the FFC energy can be represented as the product of the site energy and an FFC multiplier. Clearly, the energy used in fuel production can also be considered as a type of site energy. This apparent circularity is resolved mathematically in (Coughlin 2012), and results in a formula for FFC energy use that is a nonlinear function of the FFC energy intensity parameters.

The FFC accounting approach has been widely used in transportation energy analysis, where it is often referred to as "well-to-wheels" analysis (Wang 2002). Many of these applications use the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model developed at Argonne National Laboratories (Wang 1999; ANL 2011), which provides a comprehensive source of information on fuel cycles for vehicles. Life-cycle analysis (LCA) is similar to well-to-wheels analysis, with some important conceptual differences. Applied to manufactured products or commodities, LCA attempts to account for the use of energy, materials, and water in the production, distribution, lifetime use, and disposal of a product. LCA has been used to compare the lifetime energy use and emissions of electricity generation using different fuels and technologies (Jaramillo, Griffin, and Matthews 2007; Spath, Mann, and Kerr 1999; Spath and Mann 2000) and to estimate the emissions impacts from non-conventional fossil fuel production (A. Brandt 2008; Burnham et al. 2011; Yeh et al. 2010).

LCA studies account for the materials and energy used to build infrastructure such as roads, pipelines and refineries, much of which serves multiple uses. Some portion of this energy use, amortized over the lifetime of the infrastructure, is allocated to the product under consideration. LCA studies consistently show that the contribution of infrastructure to lifetime energy use is small, on the order of a few percent or less (Spath, Mann, and Kerr 1999; Spath and Mann 2000). In contrast, the FFC approach includes only the energy needed to maintain a given fuel production level. This includes energy required to maintain infrastructure, but not to build it. The FFC upstream energy use scales directly with the total amount of fuel produced in a given time interval, and can be thought of as the "energy operating cost" of fuel production.

The differences between the LCA and FFC methods reflect a difference in the way that time enters into the analysis. In LCA, because energy and material use is integrated over the lifetime of a product, the results will be dependent on the assumptions about the future that were made at the time when the LCA was done. This can make it difficult to compare the results of LCA studies performed at different times, and to interpret the results of LCA studies for systems that are changing significantly with time. The FFC approach uses an explicitly time-dependent framework to evaluate the impacts of policies with varying time horizons for implementation. For policies that lead to reduced energy demand in the near term the FFC approach is appropriate, because changes to the level of fuel production occur over time scales that are short compared to the length of time needed to develop infrastructure. Given a backdrop of continuously evolving economic and policy conditions, the way that near-term changes to fuel demand affects long-term decisions about infrastructure investment is poorly defined, and arguably should not be included as a policy impact *per se*.

This analysis does include the energy and emissions associated with oil and gas well drilling, completion, and maintenance. Due to physical depletion of the resource reservoir, new wells must be continuously brought on line to maintain production at a given level. Leakage of methane from the completion of natural gas wells, or from ongoing maintenance activities in established wells, contributes a significant portion of the total lifetime emissions of a natural gas production well (Alvarez et al. 2012). As unconventional gas is expected to provide a rapidly growing share of total supply, any differences between conventional and unconventional production methods should be carefully accounted for. This report makes use of several recent studies to estimate the emissions associated with unconventional fossil fuel production (DOE NETL 2011; Venkatesh et al. 2011; Burnham et al. 2011); these numbers will likely change as further research is conducted.

The major stages of the full cycle are: (1) extraction, processing, and transport of primary fuels; (2) refining or other conversion processes; and (3) transmission and distribution to final consumers. Both primary fuels and grid electricity are used at each stage. Strictly speaking, electric power is an energy carrier rather than an energy source, so accounting for the use of grid electricity in the fuel cycle requires information on how it is produced. For electricity generated from fossil fuels, the upstream energy use is equal to the energy required to produce the fuels burned at the power plant. For electricity generated by renewable fluxes[2], the upstream fuel cycle energy use is approximated here as zero, as the small amount of fossil fuels used in operation and maintenance of renewable power plants is not significant relative to the overall precision of the calculations. The details are discussed below in Section 3.1.

To develop projections of the FFC energy and emissions factors over time, forecasts of fossil fuel production, electricity generation, and other variables are taken from the 2012 edition of the *AEO* (DOE EIA 2012b). As the *AEO* does not provide all the information needed to characterize the fuel cycle, *AEO* projections are supplemented by analysis of historical data and information gathered from a review of the published literature. In particular, the GREET model and related documentation provide a detailed discussion of energy use and emissions for oil and gas production (Burnham, Wang, and Wu 2006; Palou-Rivera and Wang 2010; Bredeson et al. 2010). GREET model assumptions are also used to characterize the nuclear fuel cycle (Wu et al. 2006).

[2] Renewable fluxes include wind, solar, hydropower, and geothermal.

The rest of this report is organized as follows: Section 2 provides a summary of the methodology and defines the FFC energy and emissions factors as a function of the physical parameters. Section 3 presents our estimates of these parameters. Calculations of the FFC multipliers for energy and emissions are presented in Section 4. These results are compared to estimates calculated using the GREET model for the U.S. Department of Energy (DOE) (DOE EERE 2011). The uncertainties in the data, and how continuing research is likely to affect the FFC estimates, are discussed in Section 5.

2. Approach

To illustrate the concepts involved, we consider a simple situation with only one type of fuel. We define:

- F as total economy-wide energy consumption;
- Q as total energy consumption minus the amount used in fuel production; and
- c as the energy intensity of fuel production, defined as the quantity of fuel used per unit of fuel output.

By definition, the energy consumption of the fuel production sector is equal to the product cF. It follows that $F = Q + cF$; the economy-wide demand for energy is equal to the amount used in the fuel production sector plus the amount (Q) needed for all other end uses,.

Conceptually, the FFC multiplier represents the total amount of energy required to provide one unit of energy to the final consumer, which is equal to the ratio F/Q. Thus, the fuel cycle multiplier, denoted by μ (mu), is given by

$$\mu = F/Q = F/(F-cF) = 1/(1-c).$$

If efficiency or some other policy changes the demand for end-use energy (Q), then the corresponding change in total energy (F) is obtained by multiplying by μ. As the formula for μ is a nonlinear function of the parameter c, changes to the value of c can have a large impact on the value of μ. This approach is generalized to the case of multiple fuels in (Coughlin 2012) and summarized in the next section.

2.1 Energy Accounting

The detailed accounting methodology is provided in (Coughlin 2012); here we summarize the notation and parameter definitions. The FFC multiplier and related metrics are defined as s a function of a set of parameters representing the energy intensity and material losses at each production stage. Electricity is accounted for by defining two sets of parameters that represent primary fuel use in electricity production and electricity use in primary fuel production. The parameters depend only on physical data, *i.e.*, the calculations do not require any assumptions about prices or other economic data. Parameter values may vary by geographic region, time, or any other variable that affects the energy intensity of fuel production.

The indices *x* and *y* are used to indicate fuel type, with *x=c* for coal, *x=g* for natural gas, *x=p* for petroleum fuels, *x=u* for uranium, and *x=r* for renewable fluxes. In the emissions accounting, the index s is used to indicate pollutant type. The fuel cycle parameters are:

- a_x is the quantity of fuel x burned to provide one unit of grid electricity, including the effect of transmission and distribution system losses; it is referred to as the burn rate;
- b_y is the amount of grid electricity used to produce a unit of fuel y;
- c_{xy} is the amount of fuel x used to produce one unit of fuel y;
- V_{xy} is the total amount of fuel x used to produce one unit of fuel y; $V_{xy} = a_x b_y + c_{xy}$;
- M_{xy} is a matrix representing the total reduction in demand for fuel x that results from reduction in demand of one unit of fuel y; it can be thought of as a matrix of multipliers;
- q_x is the heat content of fuel x in MBtu/physical unit, based on low heating value; [3]and
- $z_x(s)$ is the emissions intensity for fuel x (mass of pollutant *s* per physical unit of x).

The FFC multiplier matrix **M** is defined by the equation

$$\mathbf{M = (I - V)^{-1}}.$$

This is the analogue of the nonlinear formula given above for the case of a single fuel. The coefficients of the matrix **M** define the economy-wide impacts of changes in fuel demand in physical units, so they effectively determine both the energy and emissions impacts of the full fuel cycle.

2.2 Definition of FFC Factors for Energy and Emissions

The definition of fuel-specific multipliers is a convenient way to summarize the information contained in the matrix **M**. These are obtained by combining the matrix **M** with the appropriate energy or emissions intensity factors for each fuel type.

The FFC matrix is derived by considering the effect of a change to end-use energy demand by an amount **f**. The economy-wide, or FFC change, to energy demand that results is equal to $\mathbf{M \cdot f}$. Setting $\mathbf{f' = M \cdot f}$, and defining $\mathbf{M = I + U}$ we can write

$$\mathbf{f' = M \cdot f = f + U \cdot f}$$

The term **f** represents the site fuel savings, and $\mathbf{U \cdot f}$ represents the upstream fuel savings. This expression assumes all fuel quantities are defined in physical units; to define a multiplier, different fuel types need to be represented using equivalent units. This is done using the heat content **q**. The energy content in the fuels represented by **f** is equal to $\mathbf{q \cdot f}$, and the multiplier is defined as the ratio

$$\mu = \mathbf{q \cdot M \cdot f / q \cdot f} \qquad \mathbf{(1)}$$

[3] One MBtu is equal to one thousand Btu; one MMBtu is equal to one million Btu.

Multipliers for a specific fuel type are obtained by setting the components of **f** equal to one for the given fuel and zero for all other fuels. In summary:

- For coal, the multiplier is

$$\mu_c = \sum_x q_x M_{xc}/q_c$$

- For natural gas, the multiplier is

$$\mu_g = \sum_x q_x M_{xg}/q_g$$

- For petroleum products such as fuel oil, the multiplier is

$$\mu_p = \sum_x q_x M_{xp}/q_p$$

For electricity, upstream energy use is defined as the energy needed to produce the fossil fuels that are burned at the plant. By definition, the quantity of fuel *x* needed to generate a unit of grid electricity is equal to a_x. Hence, the multiplier is obtained by setting **f** equal to **a**:

$$\mu_{elec} = (\mathbf{q}\cdot\mathbf{M}\cdot\mathbf{a}) / (\mathbf{q}\cdot\mathbf{a}). \qquad \mathbf{(2)}$$

There are some subtleties in this definition, as not all electricity is generated by fossil fuels. These are discussed in more detail in Section 3.1 below. The multiplier is meant to be applied to site energy quantities that have been converted to standard units. For electricity, conversion of site kWh to energy units is typically done through a "site-to-source" conversion factor. In our terminology, this factor is equal to **q·a**. It should be applied before the FFC multiplier is used. The factor **q·a** is equal to the energy content of the mix of fuels required to provide one unit of site electricity, including transmission and distribution losses.

The analysis of FFC emissions uses the same logic as the energy accounting. Given a site fuel demand decrement **f** and the FFC decrement **f'**, the FFC emissions decrement is given by

$$\mathbf{z\cdot f' = z\cdot M\cdot f = z\cdot f + z\cdot U\cdot f} \qquad \mathbf{(3)}$$

where z_x is the emissions intensity (in mass of pollutant per physical unit) for fuel x. The term **z·f** corresponds to emissions associated with site fuel **f**, and the term **z·U·f** to the emissions associated with the energy used upstream.

There are two physically distinct sources of emissions: those arising from combustion of fossil fuels, and those arising through leakage or evaporation of pollutants directly into the atmosphere. The latter are generally known as fugitive emissions. In defining upstream emissions, to be consistent with the intuitive notion of upstream, the emissions factors are separated into a combustion term **z1** and a fugitive term **z2**, with **z** = **z1** + **z2**. When an amount of fossil fuel equal to **f** is used (i.e. burned) at a site, the total FFC emissions are equal to

$$\mathbf{z\cdot f + z\cdot U\cdot f = z1\cdot f + z1\cdot U\cdot f + z2\cdot f + z2\cdot U\cdot f.} \quad \mathbf{(4)}$$

The only emissions that occur at the actual consumption site are given by $\mathbf{z1{\cdot}f}$**;** the other three terms represent emissions that occur at locations along the fuel production chain (*i.e.,* at the mine, oil field, etc.). Hence, it is more consistent with the intuitive notion of upstream to define the upstream emissions as the sum ($\mathbf{z1{\cdot}U{\cdot}f + z2{\cdot}f + z2{\cdot}U{\cdot}f}$). We emphasize that this is a convention defining the *meaning* of the expression "upstream emissions" and does not affect anything to do with the calculations themselves. In this paper we define

- site emissions as being equal to the site combustion emissions $\mathbf{z1{\cdot}f}$**;**
- upstream FFC emissions as being equal to the upstream combustion emissions plus the total fugitive emissions, $\mathbf{z1{\cdot}U{\cdot}f + z2{\cdot}f + z2{\cdot}U{\cdot}f = z1{\cdot}U{\cdot}f + z2{\cdot}M{\cdot}f}$**;** and
- Total FFC emissions as being equal to the sum of site plus upstream emissions.

For some pollutants, the emissions intensity depends on the combustion technology; this is especially true for NOx emissions. This dependence is dealt with by generalizing the fuel type index x defined above to represent the combination of a fuel and technology. The entries of the matrices $\mathbf{V}$, $\mathbf{M}$ and $\mathbf{U}$ are disaggregated into fuel intensities for each of the relevant technology types, but otherwise the accounting methods do not change. If desired, one could also define multipliers for the emissions; these may, however, be less useful, as they obscure the distinction between fugitive and combustion emissions.

The equations show that, apart from the heat content and emissions intensities for each fuel, all the information about the fuel cycle is contained in the matrix $\mathbf{M}$, which depends only on the matrix $\mathbf{V}$. Hence, most of the work in developing the FFC accounting is concerned with the calculation of the elements of $\mathbf{V}$.

2.3 Emissions Data

Table 1 provides a summary of emissions data, compiled from a review of the literature and converted to physical units. Emissions associated with combustion include all the pollutants considered in this study, while fugitive emissions consist of methane and carbon dioxide. More detailed discussion of the physical sources for fugitive emissions is provided in the fuel-specific sections below.

Data sources frequently present emissions intensities relative to the fuel energy content rather than fuel physical units; these are converted to physical units using the fuel heat content (EPA 2011a). The data for combustion emissions of GHGs are taken from tables compiled by the U.S. Environmental Protection Agency (EPA) (EPA 2011a). Data for fugitive emissions of GHGs during coal, oil, or natural gas production are compiled from several recent studies, some of which have been used to develop inputs to the GREET model (Brinkman et al. 2005; Burnham et al. 2011; Venkatesh et al. 2011; A. Brandt 2011). Fugitive emissions depend on the production method; for coal the most important distinction is underground versus surface mining, while for gas and oil the distinction is between conventional and unconventional production. Unconventional production covers coal bed methane, tight gas reservoirs, shale gas, tight oil, oil shale, and tar (bitumen) sands. In general, fugitive emissions of methane are the most significant component of the upstream contributions to the FFC emissions; FFC carbon dioxide emissions are measurable, but small, compared to the site combustion emissions of CO_2.

For natural gas and petroleum fuels the combustion emissions intensities depend on the technology. Emissions intensities for mobile, stationary external and stationary internal combustion are drawn primarily from the Environmental Protection Agency's report *AP 42 Compilation of Air Pollutant Emission Factors* (AP42) (EPA 2011b)(AP42). More detail on the breakdown of fuel use by technology type is provided in the fuel production chain sections. In some cases mobile source emission factors are taken from the GREET model, as indicated in the table.

Time-dependent estimates of power sector combustion emissions for SO_2, Hg, and NO_x are based on *AEO 2012* projections of annual estimates of total generation by fuel type and total emissions of each pollutant. *AEO* projections of the mix of coals used for power generation are used to calculate time-dependent CO_2 factors, and projections of the relative proportion of conventional vs. non-conventional oil and gas supply are used to develop time-dependent fugitive emissions factors for CH_4 and CO_2. All other emissions factors are assumed to remain constant. For the time-dependent quantities, Table 1 shows values for 2010.

Table 1 Summary of combustion emissions data[4]

Species	Fuel	Technology	Units	Value	Source
CO_2	coal	stationary	kg/mmbtu	95.6	a
CH_4	coal	stationary	g/mmbtu	11	a
N_2O	coal	stationary	g/mmbtu	1.6	a
SO_2	coal	power plant	g/mmbtu	204	c
NO_x	coal	power plant	g/mmbtu	0.094	c
Hg	coal	power plant	g/mmbtu	0.0018	c
NO_x	natural gas	stationary - external	g/mmbtu	68.4	d
SO_2	natural gas	stationary - external	g/mmbtu	0.265	d
CH_4	natural gas	stationary - internal	g/mmbtu	658	e
CO_2	natural gas	stationary - internal	kg/mmbtu	49.9	e
NO_x	natural gas	stationary - internal	g/mmbtu	907	e
SO2	natural gas	stationary - internal	g/mmbtu	0.272	e
CH_4	natural gas	stationary	g/mmbtu	1	a
CO_2	natural gas	stationary	kg/mmbtu	53.0	a
N_2O	natural gas	stationary	g/mmbtu	0.100	a
NO_x	natural gas	power plant	g/mmbtu	28.9	c
CH_4	petroleum - diesel	mobile non-highway	g/mmbtu	4.11	a
CO_2	petroleum - diesel	mobile non-highway	kg/mmbtu	69.9	a
N_2O	petroleum- diesel	mobile non-highway	g/mmbtu	1.78	a
NO_x	petroleum - diesel	stationary	g/mmbtu	2000	e
CH_4	petroleum - diesel	stationary	g/mmbtu	2.3	f
CO_2	petroleum - diesel	stationary	kg/mmbtu	77.4	f
N_2O	petroleum - diesel	stationary	g/mmbtu	1.5	f
NO_x	petroleum - diesel	stationary	g/mmbtu	680	f
SO2	petroleum - diesel	stationary	g/mmbtu	8	f

[4] The notation used is T for short ton; g for gram, kg for 10^3g, bbl for one American barrel, Mcf for 10^3 standard cubic feet, MBtu for 10^3 Btu, MMBtu for 10^6 Btu, and MWh for 10^6 Wh.

CH_4	petroleum - fuel oil	stationary	g/mmbtu	3	a
CO_2	petroleum - fuel oil	stationary	kg/mmbtu	74	a
N_2O	petroleum - fuel oil	stationary	g/mmbtu	0.6	a
SO_2	petroleum - fuel oil	power plant	g/mmbtu	238	c
NO_x	petroleum - fuel oil	power plant	g/mmbtu	28	c
SO_2	petroleum	stationary	g/mmbtu	38.1	d

Table 2 Summary of fugitive emissions data

species	Fuel	Source Category	Units	Value	Source
CH4	coal	underground	g/mmbtu	360	b
CH4	coal	surface	g/mmbtu	50	b
CH4	natural gas	conventional	g/mmbtu	543	b
CH4	natural gas	shale	g/mmbtu	397	b
CO2	natural gas	conventional	kg/mmbtu	1.37	b
CO2	natural gas	shale	kg/mmbtu	1.37	b
CH4	petroleum	conventional	g/mmbtu	60	g
CH4	petroleum	tar sands	g/mmbtu	110	b, h
CO2	petroleum	conventional	kg/mmbtu	1.143	g
CO2	petroleum	tar sands	kg/mmbtu	1.562	b, h

Table 3 Sources for emissions factors

a	EPA, Emission Factors for Greenhouse Gas Inventories Nov. 7 2011
b	Burnham et al. 2011
c	AEO2012
d	EPA AP42 Chapter 1 External Combustion
e	EPA AP42 Chapter 3 Stationary Internal Combustion
f	GREET1_2011 (average of diesel fuel values for stationary reciprocating engine and farm tractor)
g	Brinkman et al. 2005
h	Brandt 2011

2.4 Process Steps and Loss Rates

The coefficients b_y and c_{xy} represent the total use of electricity and fuel x for each unit of fuel y delivered to the final consumer. As the production chain consists of a series of steps, coefficients defining the energy use and material loss rates at each step must be combined to produce these FFC parameters. In this section we provide a brief summary of how these calculations are organized. The superscript index *[k]* is used to indicate successive steps in the production chain, with the energy use parameters at each step denoted $b_y^{[k]}$ and $c_{xy}^{[k]}$. Material losses at step k are accounted for by defining the fraction of material that passes from step k to step $k+1$ as $\gamma^{[k]}$ (gamma); the percentage loss at step k is therefore equal to $1-\gamma^{[k]}$. The energy use coefficients are always defined per physical unit of material input to that process step.

As an example, consider the electricity use for a 3-step process with k=0, 1, 2 representing extraction, processing, and distribution. In this example, to lighten the notation we drop the subscript that defines the fuel type. Let $b^{[0]}$, $b^{[1]}$, and $b^{[2]}$ be the electricity use per unit of material handled in each step, and $\gamma^{[1]}$ and $\gamma^{[2]}$ be the fractions of material passed from step 0 to step 1 and from step 1 to 2, respectively.

- The electricity use in step 0 is $b^{[0]}$ per unit of material extracted.
- The electricity use in step 1 is $b^{[1]}$ per unit of material processed, or $b^{[1]} \gamma^{[1]}$ per unit of material extracted.
- The electricity use in step 2 is $b^{[2]}$ per unit of material distributed, or $b^{[2]} \gamma^{[2]} \gamma^{[1]}$ per unit of material extracted.

The total electricity use per unit of material extracted is the sum $b^{[0]} + b^{[1]} \gamma^{[1]} + b^{[2]} \gamma^{[2]} \gamma^{[1]}$. The FFC coefficient b, is defined as the electricity use per unit of fuel delivered; to convert from units of material extracted to units delivered, the sum is divided by $\gamma^{[2]} \gamma^{[1]}$, which gives

$$b = (b^{[0]} + b^{[1]} \gamma^{[1]} + b^{[2]} \gamma^{[2]} \gamma^{[1]}) / (\gamma^{[2]} \gamma^{[1]})$$

This approach can be generalized to any number of steps, for any of the required parameters.

3. Calculation of the Parameters

The elements of the multiplier matrix **M** are dependent on the physical parameters **a**, **b,** and **c**; the data and methods used to calculate these parameters are presented in this section. The **a** parameters depend only on the characteristics of electricity production. The **b** and **c** parameters depend on the details of the production chains for coal, natural gas, and petroleum-based fuels.

3.1 Electricity Production

The burn rate a_x is defined as the amount of fuel x consumed per MWh of grid electricity delivered to consumers in a given region. As a_x is used to relate site consumption of electricity to total fuel requirements, it includes a factor to account for transmission and distribution losses, which are independent of the fuel type x. The value of a_x depends on three factors that can vary independently:

- the fraction of all electricity that is generated by fuel x;
- the power plant conversion efficiency for technologies using fuel x; and
- the heat content of fuel x.

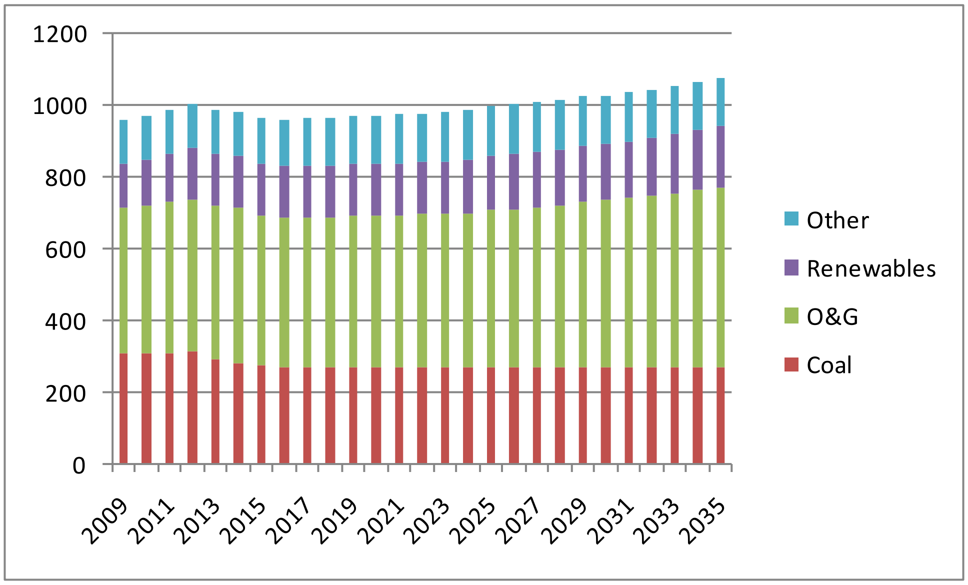
The burn rate thus depends on the capacity mix in the region; in particular, the higher the penetration of capacity of type x, the higher the value of a_x.

For fossil fuels, the value of a_x is straightforward to calculate either from historical data available through EIA (DOE EIA 2012c) or from NEMS output (DOE EIA 2012b). *AEO* provides projections of total fuel consumption for power production by fuel type and total sales to consumers. The ratio of these two numbers is equal to the product $a_x q_x$. *AEO* also projects annual average values of q_x, so the value of a_x can be isolated. Values based on *AEO 2012* are listed in Table 4. Time variation in the value of a_x comes primarily through changes in the proportion of different fuels used to produce electricity. The trend currently forecast by the *AEO* is slow growth in the fraction of power generated by natural gas and renewables, with other sources remaining relatively flat. Within the renewables category, new capacity is primarily forecast to be wind. These trends are illustrated in Figure 1; in this figure, the “other” category is made of nuclear power, distributed generation, and pumped storage.

Table 4 Values of a_x calculated based on data from *AEO 2012*.

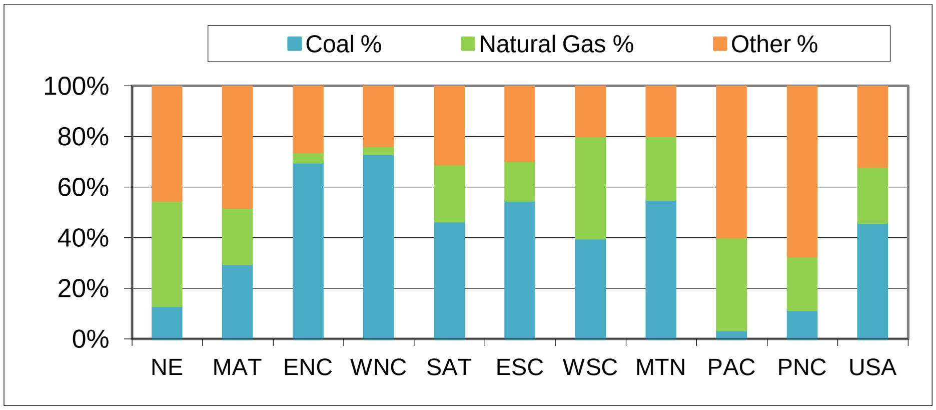
Year	Coal T/MWh	Fuel Oil bbl/MWh	Nat Gas Mcf/MWh
2010	0.264	0.0178	2.00
2015	0.228	0.0137	2.19
2020	0.232	0.0136	2.06
2025	0.239	0.0135	1.97
2030	0.236	0.0130	2.05
2035	0.234	0.0130	2.10

Figure 1 *AEO 2012* forecast of total annual generation by fuel type.



Regional variation in the use of different fuels is significant, as illustrated in Figure 2, which shows the percent of generation by fuel type and by census division. In the figure, all generation except natural gas and coal are included in the “other” category. These proportions are calculated based on historical data for 2009.

Figure 2 Proportion of generation by fuel type and by census division, 2009 data.



To complete the description of the electric power system, values of a_x for renewables and nuclear generation must be defined. For renewables, strictly speaking there is no such thing as a heat rate. The quantity of "primary energy" in the sun or wind is of academic interest only, as it cannot be conserved in any meaningful sense. However, to be consistent with the convention used in the *AEO*, the energy or heat content (q_x) of a MWh of electricity generated by renewables is defined by setting it equal to the grid average fossil thermal value. For renewable power plants, the conversion efficiency is set equal to one; hence, the resulting value of a_x is equal to the fraction of electricity generated from renewable fluxes.[5]

Calculation of the coefficient a_x for nuclear power uses a slightly different methodology. *AEO* provides total annual electricity (MWh) generated by nuclear plants, and total energy consumption (in quads) by nuclear power plants. The ratio of these two numbers provides an average heat rate for nuclear power, which in *AEO 2012* is equal to 10.46 MBtu/kWh, with almost no variation over the forecast period. The value of a_x is equal to the quads used by nuclear plants divided by the heat content of nuclear fuel. In this analysis we use the convention adopted in the GREET model (Wu et al. 2006), which sets the energy content of a unit of uranium equal to the energy content of the electricity it can generate. [6] This approach is reasonable because the use of uranium for energy is confined to the electric power sector; in this respect the intrinsic energy content of uranium, like the energy content of wind or solar radiation, is of academic interest only.

The projections in *AEO* are widely used to estimate the net benefits of energy policies whose impact is extended over time. The uncertainty in these projections is difficult to quantify. To provide some insight into this issue, we compare in Table 5 the total capacity (in GW) for coal and renewables, as forecast by the *AEO 2011*, to the same forecasts published in the *AEO 2012.* In the more recent edition of *AEO*, there is a substantial decrease in the anticipated coal capacity additions, largely made up through increased penetration of renewables. In 2035, the final year

[5] We exclude biomass from our definition of renewable fluxes. The analysis of biomass use in power generation is more similar to that of fossil fuels, as the heat content and power plant conversion efficiencies are well defined. But biomass constitutes such a small fraction of total power generation that it is not quantitatively important.

[6] This is equivalent to a fixed conversion efficiency for nuclear plants of about 33%.

of the analysis period, coal capacity is down 14%, and renewables (primarily wind) is up 14% relative to the previous year edition of the *AEO.* The parameter a_x is proportional to the relative capacity for each fuel, so a variation on the order of 10% in these capacity forecasts will change a_x by a similar amount.

Table 5 Comparison of the forecast capacity (GW) for coal and renewables in AEO versions 2011 and 2012 (power sector only).

	AEO 2012			***AEO 2011***		
Year	**Coal**	**Renewables**	**Total**	**Coal**	**Renewables**	**Total**
2010	308.1	125.2	970.6	313.5	122.4	973.4
2015	276.7	144.4	963.2	312.5	135.7	984.0
2020	269.8	145.8	972.1	313.1	136.6	986.8
2025	269.8	151.2	997.8	313.1	141.1	1010
2030	269.9	156.1	1029	313.1	144.9	1050
2035	270.4	169.3	1077	313.4	147.9	1090

These changes do not result from any change in the precision of the *AEO* forecast methodology. Instead they reflect year-to-year changes in policies (such as pollution regulations and portfolio standards) and changes in market and price trends that are carried into the updated model. This type of uncertainty about the future is fundamental to all exercises in forecasting. In this case, the uncertainty in the *AEO* forecasts defines an intrinsic level of uncertainty in any analysis that relies on such projections. In practical terms, it sets a lower bound on the precision of the parameter estimates; this suggests that reducing the uncertainty in the other data that enter this calculation to less than 10% would not alter the precision of the overall calculation.

3.2 Coal Production

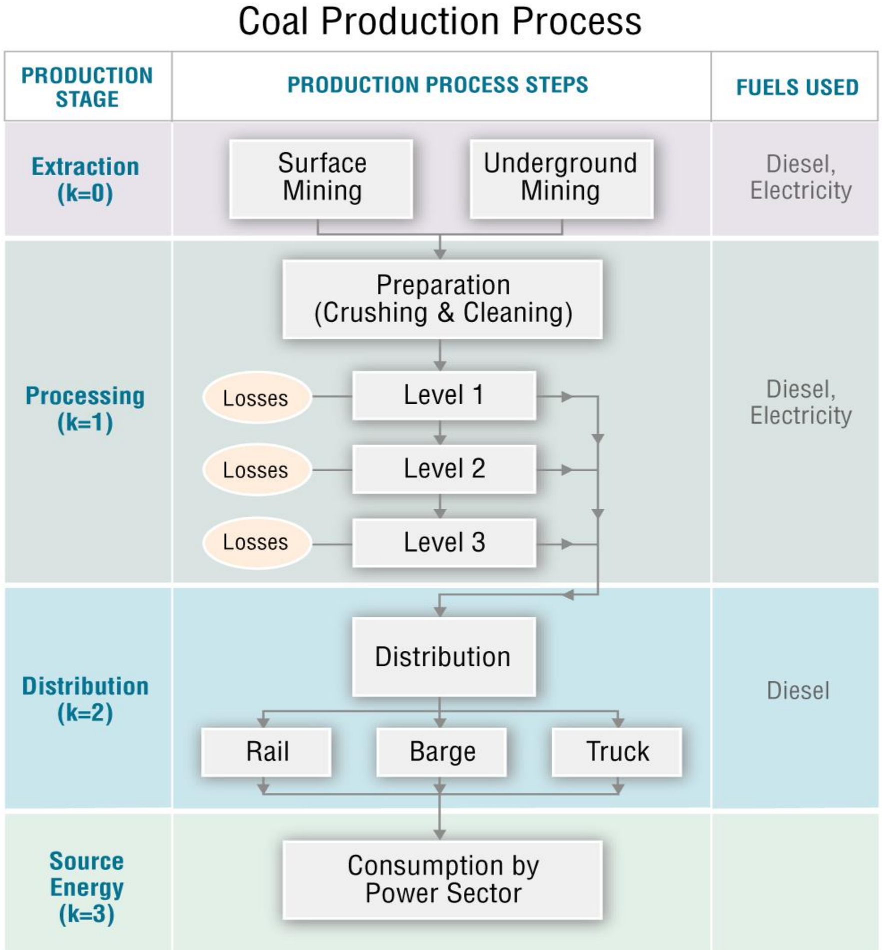
The coal production chain consists of extraction, processing, and transportation to the consumption site, as outlined in Figure 3. There are several sources of variability in the production chain that affect energy use, including the type of mining method, the coal quality and sulfur content, the transportation mode, and transportation distances. Mining methods and coal quality are largely determined by geological conditions, which in turn correlate primarily with the region in which the coal is produced. The level of cleaning required is dependent primarily on coal sulfur content and to some degree on the requirements of the user.

3.2.1 Industry overview

Most of the coal consumed in the United States is produced domestically. Coal reserves are concentrated in a few large basins, loosely identified as the Western, Interior, and Eastern or Appalachian (NAS 2007). Coal is classified into categories, or ranks, related to heat content: anthracite, bituminous, sub-bituminous, and lignite. Anthracite is the highest quality and is generally not used in power generation. The sulfur content of coal also varies widely and tends to be characteristic of a particular region (DOE EIA 2011). Extraction methods are broadly categorized into surface and underground, with the choice of method dependent on the depth of the coal and the dimensions of the coal seam. Eastern coal seams tend to be deeply buried, necessitating underground methods, and the coal generally has a high heating value. In the Western region, seams are relatively thick and shallow, and the coal has a low heating value (NAS 2007). Surface mining involves fracturing and removing the overlying soil and rock, breaking the coal by blasting or mechanical means, and loading the coal for transport to its final destination. In the Appalachian region coal is also mined using the surface technique of mountain top removal. Underground mining techniques are typically more energy intensive and tend to be used primarily in the Eastern region in higher quality coal seams. There are several varieties of underground mining methods, which vary with the geology of the coal seam and the degree of automation.

Most underground mining is now automated. The two most commonly used methods of underground mining are room-and-pillar and longwall (NAS 1995). In room-and-pillar mining, the coal is removed from two sets of corridors that advance through the mine at right angles to each other. Regularly spaced pillars, constituting about half the coal seam, are left behind to support the overhead layers in the mined areas. The pillars may later be removed, leading to probable subsidence of the surface. In longwall mining two parallel headings are made about 100-200 meters apart and at right angles to the main heading. The longwall between the two headings is then mined away from the main heading. The equipment provides a movable roof support system that advances as the coal is mined and allows the roof to collapse in a controlled manner behind it. This method also leads to subsidence of the overhead layers.

Figure 3 Schematic of the coal production chain. The steps indexed by k are in the leftmost column, and the fuels used are identified in the rightmost column.



After extraction, coal goes through a preparation process consisting of crushing, grinding, and separation, which is used to create coal particles of a uniform size and to remove sulfur and other impurities (Gagarin et al. 2008; Skea and Rubin 1988). In crushing, the material produced at the mine is reduced to a more uniform consistency; grinding further reduces the size of the material particles. In the separation step, the useful coal particles are separated out from the rest of the material; this may also be referred to as cleaning or washing. Washing involves a process using a liquid medium that allows the lower density "clean" coal particles to be separated from the higher density refuse particles. Once the coal has been cleaned, it is dewatered through the use of vibrating screens or centrifuges, and the refuse may be land-filled or reconstituted as waste coal (Herhal and Minnucci 1991; Skea and Rubin 1988). During preparation, material losses can be significant, but since much of the removed material is non-carbonaceous, the heat content losses are somewhat less. On average, the yield of saleable coal is about 81% of the total material extracted (DOE EERE 2007). Estimates of the energy efficiency of these processes vary widely.

Coal is transported to power plants primarily by rail and barge, supplemented by truck transportation (DOE EIA 2012d). The fuel used for transportation is primarily diesel and fuel oil. Burning of coal at power plants produces a significant quantity of ash. Data compiled through

EIA Form 923, Schedule 8 (DOE EIA 2012e) indicates that approximately 1/3 of this material can be used in other manufacturing processes, while the rest is either stored on-site or disposed of in ponds or in land-fill. A complete description of the coal fuel cycle should include energy use for these activities, but due to lack of data they are not accounted for in the current model.

3.2.2 Data sources

The FFC parameter calculations are organized to make use of the forecasts produced by *AEO*. For coal production, *AEO* provides annual output by coal category and sulfur content (low, medium, and high) for the three major production regions. *AEO* does not provide proportions of total coal output by mining type. To estimate the fraction of coal produced by surface versus underground mining, we use historical data from the Annual Coal Report (DOE EIA 2011), which lists production by state, coal quality, and mining technique. These data, for the year 2007, are summarized in Table 6.

Table 6 Coal production data for 2007, Annual Coal Report.

AEO Region	State	Production (1,000 Tons)	%Surface Mined	Average MBtu/Ton	Sulfur %
Appalachia	KY	107,213	45%	24.3	1.65
Appalachia	WV	94,627	44%	24.5	1.36
Appalachia	PA	48,742	17%	23.9	1.97
Appalachia	OH	27,178	35%	24.5	3.41
Appalachia	VA	19,403	36%	25.2	0.99
Appalachia	AL	10,148	40%	24.0	1.43
Appalachia	MD	4,173	74%	24.2	1.80
Appalachia	TN	1,510	66%	25.6	1.23
Interior	TX	40,628	100%	12.9	1.02
Interior	IN	30,437	66%	22.3	2.46
Interior	IL	28,518	18%	22.9	2.44
Interior	MS	3,387	100%	10.2	0.47
Interior	LA	1,546	100%	13.7	0.73
Interior	OK	769	70%	21.1	2.62
Interior	KS	512	100%	22.3	3.86
Interior	MO	21	100%	21.8	3.66
West	WY	429,840	99%	17.3	0.31
West	MT	42,076	100%	17.9	0.48
West	CO	30,511	24%	22.4	0.51
West	NM	24,172	73%	18.6	0.76
West	ND	23,711	100%	13.0	0.76
West	UT	22,060	0%	22.9	0.61
West	AZ	7,937	100%	21.8	0.55

The table shows the number of short tons used for power generation by producer state and region, the percentage obtained by surface mining, the average heat content (Btu per ton), and the sulfur content (percent by weight). Within each region, the rows are ordered by the number of tons produced. Wyoming alone produces more than 40% of the coal used for power generation in the United States, and Kentucky and West Virginia together produce another 20%. The data show that Western coal seams generally have lower sulfur and heat content than Eastern.

The energy used in extraction is either diesel or electricity. Conventional underground mining methods, which require electricity for lighting and ventilation as well as equipment operation, are used only for premium (anthracite) coal production and are not relevant for power generation. Information on the energy intensity of mining methods has been compiled from two DOE mining industry review reports (DOE EERE 2002; DOE EERE 2007) and a life-cycle analysis study of coal-fired generation (Spath et al. 1999). The U.S. Economic Census reports on the mining industry (U.S. Census Bureau 2002) also provide some information on energy use in a highly aggregated form. The DOE 2002 and life-cycle analysis reports use production models to estimate the diesel fuel and electricity use, per ton of coal produced, for representative mining configurations by region. In these models, detailed estimates of equipment use (trucks, drills, pumps, *etc*.) per ton of material produced are used to derive the average fuel use. Different mining regions and methods are modeled separately, including eastern underground (conventional and longwall), interior surface, and western surface mining.

Table 7 summarizes the estimates used in this analysis, based on a review of the cited literature. The energy use data for underground mining in all regions are based on the eastern longwall model estimates, and the interior surface model values are used for Appalachian surface mining. The 2002 DOE study cites a value of about 94 MBtu/ton for preparation of eastern coal, while the 2007 DOE study sites a national average of about 107 MBtu/ton for materials handling, grinding, crushing, and separation. The latter figure includes diesel for material haulage. Neither source provides a breakdown of processing energy use by fuel type, which is presumably a combination of grid electricity, petroleum fuels, and site-generated electricity or steam. Here we use a value of 90 MBtu/T on average for processing. This is somewhat lower than the DOE 2007 number and closer to the model value. We make this adjustment because it is possible that some of the diesel fuel for material haulage in the DOE 2007 study would be counted as part of extraction in the more detailed model. The fuel mix for processing is adjusted so that the fuel mix for the production chain as a whole is roughly consistent with the fuel shares assumed in the GREET model. GREET assumes that approximately 65% of energy used in coal production is from petroleum fuels, 25% from electricity, and 10% from coal. The primary energy-consuming steps in processing are material handling and grinding, which are necessary for all levels of processing. No data are available on the energy use for other aspects of processing, so we use the same energy intensity for all preparation levels.

Estimates of the material losses in cleaning are based on data from an EPA report (Herhal and Minnucci 1991) giving the fraction of coal that is processed by region and by processing level. In this report, processing methods are grouped into three categories: “no processing”, which includes some crushing and grinding but no cleaning; Level 1 which includes crushing, grinding, and screening; and Level 2-4, which covers a variety of methods of washing and cleaning. As the primary purpose of cleaning is to remove sulfur, in this analysis we assume the EPA category “no processing” applies to low sulfur coal, Level 1 processing to medium sulfur coal, and Level 2-4 to high sulfur. A 5% material loss is assigned to the “no processing” category to account for losses during crushing and grinding, and higher heat content losses for the cleaning processes are assigned to higher sulfur coals as shown in the table. The EPA report does not provide data on energy use for processing.

Table 7 Summary of data on energy use and fugitive emissions from coal production.

Extraction Energy Use MBtu/T				
Region	Method	Diesel	Electricity	fraction
Appalachia	underground	70	40	60%
Appalachia	surface	70	20	40%
Interior	underground	70	40	44%
Interior	surface	70	20	56%
West	underground	70	40	9%
West	surface	40	20	91%
Processing Energy MBtu/T				
	Coal	Diesel/Fuel Oil	Electricity	
All regions	20	35	35	
Processing Yield by Preparation Level				
	Level1	Level 2-4	No Prep	
Yield	90%	85%	95%	
Transportation Energy MBtu/T and Percent by Mode				
	Average	%Rail	%Barge	%Truck
Appalachia	199	29%	22%	49%
Interior	301	15%	54%	31%
West	229	80%	7%	13%
Fugitive Emissions Factors g CH4/MMBtu				
	Underground	Surface		
Extraction	279	43		
Processing	42	7		

The Coal Distribution Report, published by EIA, provides data on the quantity of coal shipped by origin state, destination state, and mode of transport (DOE EIA 2012d; DOE EIA 2012f). Nationwide, about 73% of tonnage is moved by rail, 9.3% by water, 11% by truck, and the rest by other modes. All these modes of transport are fueled by diesel or fuel oil. The EIA data do not include any estimate of the distances travelled. These distances are estimated here based on the approximate distance between centrally located cities in each state. Within-state transportation distances are estimated as one half of the square root of the state area. A unit of coal may travel anywhere from one to nine hundred miles before being used. Based on state-to-state quantity, distance, and mode, the average distance travelled by rail is 480 miles, by water is 310 miles, and by truck is 275 miles.

Data on fuel intensity for rail and truck freight movement were obtained from a comparative study of the energy intensity of different modes of transportation across a variety of freight movements (ICF International 2009). A representative fuel efficiency for rail transport is 350 ton-miles/gal, and for truck transport it is about 100 ton-miles/gal. Data on ton-miles carried and the quantity of fuel consumed by water transport are provided by the Bureau of Transportation statistics (BTS 2011). The median value of energy intensity over all years for which data are available is about 80 ton-miles per gallon. The energy contents of fuel oil and diesel are nearly the same, so we need not distinguish which type of fuel is used.

To fully account for the energy used in transportation, the weight of the vehicle and the fuel consumed in the return trip should be included in the calculation. If the distance travelled is d, the weight of the cargo is w_c, and the weight of the vehicle is w_v, then the total ton-miles for the round trip is equal to $(w_c + w_v)\, d + w_v d$. The round-trip factor is defined as the ratio of the total ton-miles to the cargo ton-miles, which is equal to $1 + 2w_v / w_c$. Assuming coal is loaded to the maximum allowable weight, for rail the vehicle weight is about 1/10 of the total, so the round-trip factor is 1.2. Given lack of data, we assume the same value for the other transportation modes.

The data on coal distribution can be aggregated to estimate the average distance a unit of coal travels before being consumed, by producer region and by transport mode. Multiplying by the energy intensity of each transport mode gives the energy intensity of distribution to the consumer (*i.e.,* the power plant) per ton. These data are summarized in Table 7.

Mining and processing of coal also leads to fugitive emissions, primarily of methane. Burnham and coworkers have estimated fugitive emissions for surface and underground mining, shown in Table 7 (Burnham et al. 2011). When the extraction and processing loss factors are included, the direct emissions of methane, in grams of CH_4/MMBtu, are 370 for underground mining and 58 for surface mining. The national average split between surface and underground mining is about 30%-70% (DOE EIA 2011), which gives an average direct emission of 278 g CH_4/MMBtu coal consumed. The preparation process also leads to additional emissions of sulfur oxides, estimated at 6.74 g SOx per MMBtu coal produced (Spath, Mann, and Kerr 1999); this has been added to the power sector emissions for coal listed in Table 1.

3.2.3 *AEO* Forecast

The *AEO* forecasts total coal production by mining region, coal quality, and sulfur category. The other data used in estimating the fuel cycle energy use are not updated in the *AEO* forecast. Hence, the following assumptions are made:

- The fraction of coal mined by underground vs. surface methods remains constant.
- The energy intensity of extraction, processing, and distribution remains constant.
- The fraction of coal transported by each transport mode remains constant.

With these assumptions, the time variation in the coal-related parameters comes primarily from the changing mix of coal properties. The degree of change is illustrated in Table 8, which shows the mix of coal production by region, coal type, and sulfur content in 2010 and 2035. For comparison, the table shows the forecast for 2035 published in *AEO 2011* and in *AEO 2012.* There is a substantial shift between the two *AEO* years, with supply of low and medium sulfur bituminous coal decreasingly significantly. For Western coal, *AEO 2011* projected a 44% growth in production by 2035; in the *AEO 2012* this growth is reduced to 24%. Changes in sulfur and heat content, and the fraction of production by region, lead to small-time variation in the value of the FFC energy for coal.

3.2.4 Issue for Further Study

The existing literature on LCA and fuel cycle analysis for coal does not account for mining site remediation or for disposal of coal ash waste from power generation. EIA Form 923 (schedule 8) data tabulated the amount of coal ash produced from power generation for the years 2007 and

2008. These data show that about 1/3 of the ash produced is used or sold and the other 2/3 must be disposed of. Ash can be disposed of in landfill or ponds or stored on-site at the power plant. It is not clear that the current disposal sites will be stable over the long term (EIP and Earthjustice 2010; Petz 2012), which may lead to additional energy costs in the future.

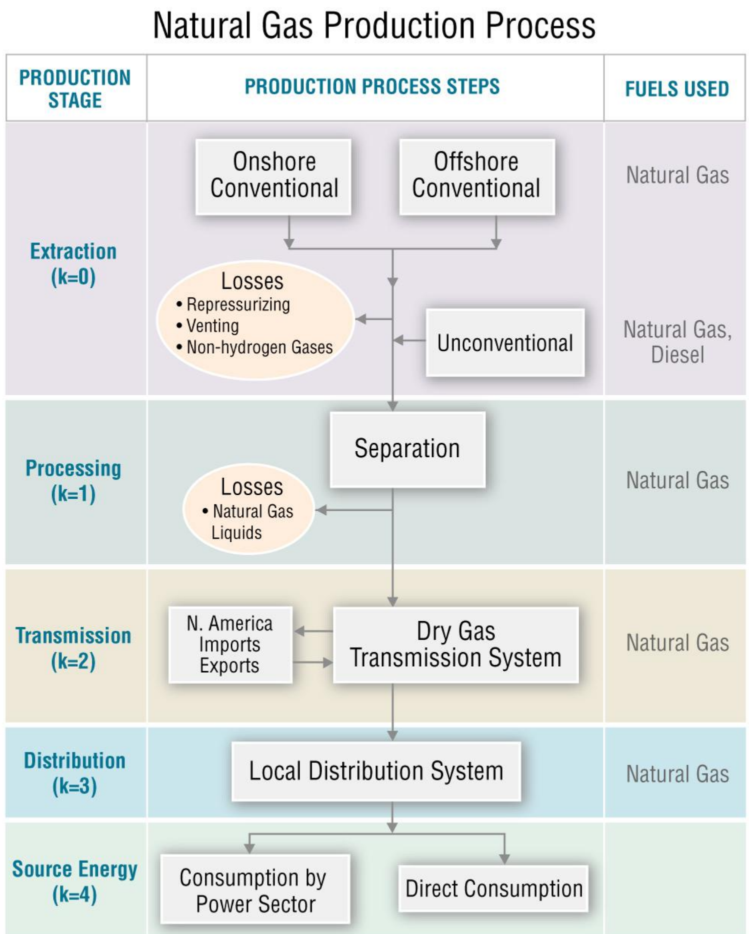
Table 8 Annual coal production (10^6 T) in 2010 and 2035. The table also compares the 2035 forecasts from *AEO 2011* and *AEO 2012*.

					AEO 2011	***AEO 2012***
Coal Type	**Sulfur**	**Region**	**2010**		**2035**	**2035**
Bituminous	Low	Appalachia	18		13	6
Bituminous	Low	West	47		68	38
Bituminous	Medium	Appalachia	168		104	78
Bituminous	Medium	Interior	12		20	8
Bituminous	Medium	West	5		5	3
Bituminous	High	Appalachia	75		105	114
Bituminous	High	Interior	96		109	125
Lignite	Medium	Interior	35		27	49
Lignite	Medium	West	29		50	42
Lignite	High	Interior	14		21	16
Sub-bituminous	Low	West	468		655	579
Sub-bituminous	Medium	West	43		78	56

3.3 Natural Gas Production

A schematic of the natural gas production chain is shown in Figure 4. The major steps are extraction, separation, transmission through the large capacity pipeline system, and local distribution. The final product, dry gas, is composed primarily of methane. Natural gas is used both in electric power production and directly as a fuel in industry and in buildings. The primary fuel input to natural gas production is natural gas itself. Small amounts of grid electricity and diesel may also be used in extraction and processing; according to the GREET model documentation, these contributions make up less than 4% of the total upstream energy use (Brinkman et al. 2005), so for simplicity they are not included in the current FFC estimates. EIA collects extensive data on production of natural gas from all sources and consumption by end use (DOE EIA 2012g). These data include the use of natural gas in natural gas production, but do not include data on the consumption of other fuels by the natural gas industry.

Figure 4 Schematic of the natural gas production chain.



3.3.1 Industry Overview

The bulk of natural gas used in the United States is produced domestically or imported via pipeline from Canada and Mexico. Conventional production is tabulated in four categories, on-shore and off-shore, and associated and non-associated. Associated refers to gas that is produced as part of oil field operations, as oil and natural gas are often found in the same geological formation. EIA divides on-shore production into six regions (Northeast, Gulf Coast, Midcontinent, Southwest, Rocky Mountain, and West Coast), and off-shore production into three regions (Gulf, Pacific, and Atlantic). The heat content of the produced natural gas does not vary significantly with source category.

In conventional production, gaseous fluids are pumped from the well, non-hydrocarbon gases are removed, and some quantity of gas may be lost to venting, flaring, or other fugitive emissions. Some gas may also be reinjected to repressurize the reservoir. The total quantity extracted from wells is referred to as gross withdrawals, and the net amount that is passed to the next production step is called marketed production or wet gas. The volumetric loss at the extraction step is about 10% (DOE EIA 2012g). The next step in the chain is the separation of wet gas into dry gas and natural gas liquids (NGLs). EIA tabulates the NGLs removed as extraction losses; when NGLs leave the natural gas production chain they enter the petroleum production chain. The energy intensity of production, loss factors, and proportion of NGLs and other constituents in the gas vary by well, and there may be a systematic variation in these quantities by supply category. However, as the EIA data are aggregated across all conventional supply sources, in this analysis we must use average values for these parameters.

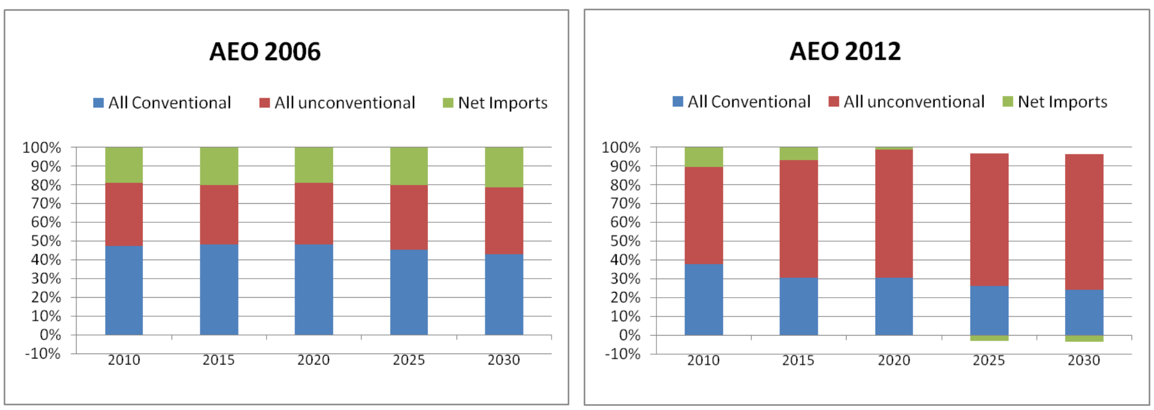
In recent years conventional gas production has peaked, and an increasingly large share of supply comes from a variety of unconventional sources (all of which fall into the on-shore, non-associated category). The broad categories are tight gas and shale gas, and coal bed methane (CBM). Tight gas refers to gas that is dispersed in sand or silt reservoirs characterized by low permeability, which is produced using techniques such as horizontal or multilateral drilling or by hydraulic fracturing (Holditch 2006; Van Dyke 2010). Shale gas refers to gas that is locked in small bubbles in layers of sedimentary rock and is distinguished geologically by the fact that the reservoir rock is also the source rock (Passey et al. 2010). Shale gas production by hydraulic fracturing (also known as "fracking") has grown rapidly in recent years. In this method, a mixture of water, sand, and chemicals is injected at high pressure into the source rock; these fluids fracture the rock and allow gas to flow back out of the well. This process requires large quantities of water and produces large quantities of wastewater, which must be removed from the well site, treated, and disposed of (Hazen & Sawyer 2009). Coal bed methane refers to methane that is trapped in the coal bed during the geological process of coal formation. Coal beds are typically permeated with water, so the water must be drawn off and disposed of before the CBM can be produced (USGS 2000). For both shale gas and CBM, there are few data available on the energy required for water management, so this aspect of the production process is not accounted for in the current analysis.

The activities involved in bringing a single well into production, and for ongoing maintenance, can lead to significant fugitive emissions. For conventional production, the necessary steps are well construction, completion, liquids unloading, and occasional workovers (DOE NETL 2011). Construction involves preparation of the site and drilling of the well bore. In completion, the well depth and size are stabilized, casing is installed to strengthen the well bore, and gathering lines and other equipment needed to extract fluids from the well are installed. Liquids unloading is an intermittent procedure used to remove water and other liquids that impede the flow of natural gas from the wellbore. A well workover is a maintenance activity in which damaged equipment is repaired or replaced. It may be necessary, during construction or maintenance when gathering equipment is off-line, to vent natural gas to the atmosphere for safety reasons. To reduce methane emissions, gas may be flared rather than vented, but this requires the installation of special equipment. For unconventional wells, fugitive emissions during well construction and completion are significantly higher than for conventional wells; this is offset somewhat by the fact that unconventional wells do not require liquids unloading (Burnham et al. 2011; DOE NETL 2011; Venkatesh et al. 2011).

Dry gas from all sources, including pipeline imports, is transported over long distances through the high-capacity interstate and intrastate transmission pipeline system. This system is operated primarily on natural gas, which may be burned on-site to generate electricity. Gas is distributed to final consumers in buildings and small industry through regulated entities known as local distribution companies (LDCs). The LDC takes natural gas out of the large pipeline system at a delivery point referred to as the citygate and moves it through a system of small-diameter, low-pressure distribution pipes. Natural gas consumed by power plants does not pass through the local distribution system.

The natural gas delivered to consumers includes net pipeline imports from Canada and Mexico and net imports of liquefied natural gas (LNG). The production chain for LNG includes additional steps that may consume significant energy. LNG currently provides less than 2% of U.S. consumption, and the current *AEO* forecast shows this proportion remaining small through 2035 (EIA AEO 2011), so this analysis does not include a model of the LNG production chain. However, this is another area where the anticipated supply mix can change significantly over time, as illustrated in Figure 5. The figure compares the projection of natural gas supply by source category as published in *AEO 2006* and *AEO 2012.* (The demand forecasts for these two editions of *AEO* are almost identical.) Before 2008, the well-documented decline in North American conventional gas production was expected to be offset by imports of LNG, which make up the bulk of the net imports category. Currently, the anticipated growth in shale gas production is expected to make the United States a net exporter of gas by 2035.

Figure 5 Comparison of natural gas supply projections *AEO 2006* to *AEO 2012*



As was noted for electricity production, successive editions of *AEO* may significantly revise the forecast supply picture. Relative to the *AEO 2011*, the 2012 edition projects U.S. natural gas production in 2035 to be 6% higher and unconventional gas production to be 8% higher. In both cases unconventional production constitutes about 75% of U.S. production in 2035.

3.3.2 Data Sources

The EIA Natural Gas Monthly (DOE EIA 2012h) and related reports provide detailed data on natural gas production and consumption (DOE EIA 2012g). The data are compiled from a survey of companies covering about 90% of production in the lower 48 states. The monthly data include “Lease and Plant” and “Pipeline and Distribution” consumption. Lease and plant consumption includes the natural gas used in well, field, and lease operations and used as fuel in separation and processing plants. Pipeline and distribution covers energy use by the transmission and distribution system.

EIA also publishes extensive data on the natural gas intra-state pipeline system capacities and average daily flows by region (DOE EIA 2012i). Table 9 provides a summary picture of inter-regional flow, based on data for the years 2006, 2007, and 2008. This flow includes imports, exports, and transfer of natural gas into and out of storage. This table shows that most of the flow in the transmission system occurs within a given region. Consequently, the distance travelled by a unit of gas to get from the producer to the consumer is assumed to be approximately uniform across the country.

Table 9 Inter-regional average daily flow (MMcf/day), average for 2006-2008.

	To Region						***Exports***	
From Region	**Northeast**	**Southeast**	**Central**	**Midwest**	**Southwest**	**Western**	**Canada**	**Mexico**
Northeast	18,135	13		509				
Southeast	3,205	18,637		4,384				
Central			22,870	11,341	2,263	2,378	54	
Midwest	1,776	172	3,613	15,647			2,199	
Southwest		12,596	4,894		34,905	3,861		531
Western						10,110	12	342
Imports								
Canada	2,914		3,659	2,537		2,602		
Mexico					50			

Fugitive emissions from shale gas production are the subject of ongoing research (Alvarez et al. 2012; Howarth et al. 2011; Tollefson 2012; Wigley 2011). The EPA conducted an extensive review of emissions from the oil and gas industry in 2009 (EPA 2009). The EPA data have been used in a DOE study to estimate the fugitive emissions at each step of the production process, for each of the major production categories (DOE NETL 2011). Emissions estimates and other gas production characteristics from the DOE-NETL study are summarized in Table 10. The fugitive emissions from well completion for unconventional production are extremely large compared to conventional wells. For both conventional and unconventional production, the one-time fugitive emissions are converted to intensity factors by dividing by the total amount of fuel produced from a well over its lifetime, which is known as the "expected ultimate recovery" (EUR). For conventional gas, EUR numbers can be predicted with reasonable accuracy (Fekete Associates 2010), but for unconventional gas the short production history means that they are still very uncertain (Venkatesh et al. 2011).

In Table 10, we use an arbitrary well lifetime of 10 years for all production categories to produce normalized emissions intensities for comparison purposes (listed in the bottom four rows). With this normalization, fugitive emissions from well completions, workovers, and liquid unloadings for tight gas and shale gas (both of which use hydraulic fracturing) are about four to five times greater than for conventional wells. These episodic emissions are the largest factor by far in the total emissions from hydraulic fracturing production methods. In reality, well lifetimes and EUR vary widely among individual wells and between different categories of production. Unfortunately, the current publicly available data do not allow a direct estimate of EUR. The well lifetimes and EUR assumed in the DOE-NETL study lead to comparable emissions intensities for both unconventional and conventional production. In this study we use the more recently updated GREET model estimates for fugitive emissions as listed in Table 1 (Burnham et al. 2011), which actually show lower emissions intensity for shale compared to conventional gas. It is unclear, given the data in Table 10, why the GREET estimates are so low.

Table 10 Summary of fugitive emissions for natural gas by production category (DOE NETL 2011).

	Conventional			Unconventional		
Production Characteristics (Units)	**Onshore**	**Associated**	**Offshore**	**Tight Sands**	**Shale**	**CBM**
Production Rate (Mcf/day)	66	121	2,800	110	274	105
Well lifetime (years) (assumed for comparison only)	*10*	*10*	*10*	*10*	*10*	*10*
EUR (Bcf/well)	0.24	0.44	10.22	0.40	1.00	0.38
Fugitive Emissions (Units)						
Well Completion (Mcf/well)	47	47	47	4,657	11,643	63
Annualized Well Completion (Mcf/well/year)	4.7	4.7	4.7	465.7	1164.3	6.3
Well Workover (Mcf/episode)	3.1	3.1	3.1	4,657	11,643	63
Well Workover number/well/year	1.1	1.1	1.1	3.5	3.5	3.5
Annualized Well Workover Mcf/well/year	3.4	3.4	3.4	16299.5	40750.5	220.5
Liquids Unloading (Mcf/episode)	23.5		23.5			
Liquids Unloading number/well lifetime	930		930			
Annualized Liquids Unloading Mcf/well/year	2185.5		2185.5			
Total Mcf/well/year during extraction	2194	8	2194	16765	41915	227
Total lb/well/year during extraction	98054	363	98054	749404	1873592	10138
Normalized emission rates (lb CH_4/Mcf)						
Completion/workover/unloadings (lb CH_4/Mcf)	0.407	0.001	0.010	1.867	1.873	0.026
Other fugitive from extraction (lb CH_4/Mcf)	0.156	0.156	0.0121	0.0121	0.156	0.156
Fugitive emissions from processing (lb CH_4/Mcf)	0.0503	0.0503	0.0503	0.0503	0.0503	0.0503
Fugitive emissions from distribution (lb CH_4/Mcf)	0.1812	0.1812	0.1812	0.1812	0.1812	0.1812

3.3.3 *AEO* Forecast

AEO projections include: natural gas production by source type, natural gas used as lease and plant fuel, and natural gas pipeline and distribution fuel use. The *AEO* production forecast is for dry gas, which in the EIA accounting system is equal to gross withdrawals minus extraction losses and the volume of natural gas liquids removed. Hence, material losses for the first step of the production chain cannot be estimated from *AEO,* and energy consumption for the first two steps of the production chain is given as a single number. This does not impact the calculation of the multiplier (Coughlin 2012). Net pipeline imports are included as part of the U.S. supply, and it is assumed that the energy use for extraction and processing of pipeline imports is the same as for domestic production, with lease and plant consumption scaled up proportionally. The EIA data for pipeline use are for the transmission and distribution of all gas including imports, so these numbers are not adjusted. For simplicity, we assume there are no losses in the transmission and distribution steps. This assumption is only used in the energy accounting; in the emissions accounting, fugitive losses from pipelines are included.

As the FFC energy use estimates are based on the lease and plant and pipeline fuel consumption projections from the *AEO,* it isn't possible to distinguish between conventional and unconventional production methods in the energy calculations. For emissions, the factors listed in Table 1 are assumed to remain constant over time, and the changing production mix is used to develop time-dependent value for the full production chain emissions $z_g(s)$.

3.3.4 Issues for Further Study

Hydraulic fracturing is water-intensive and produces large quantities of wastewater. Water is often trucked in to the production site, and wastewater trucked out to treatment plants. The actual intensity of water use, the chemical nature of the contaminants that must be removed, and the corresponding energy use requirements are not yet known with any certainty and have not been included in this study. The fracking process may also lead to local contamination of aquifers (Hazen & Sawyer 2009; Osborn et al. 2011) and higher than anticipated levels of fugitive emissions from uncontrolled fractures (Tollefson 2012). While improved management of these environmental impacts is certainly possible, it is very likely to lead to significantly higher overheads both in terms of financial costs and the complexity of the production chain. This would impact both the energy intensity of production and the growth of supply from unconventional sources.

The energy intensity and emissions from unconventional production depend sensitively on the estimated ultimate recovery, which is also highly uncertain. Standard industry practice is to fit initial well production data to a curve of production versus time or production versus cumulative production. Integrating this curve out to the point at which the production rate is no longer economic provides a value for EUR (Fekete Associates 2010). The choice of the functional form to use in fitting the data can only be validated by actual production data for a large enough sample of wells. There is some evidence that current estimates of EUR for shale gas may be overstated (Berman 2009), but further analysis of the data is needed. If production per well is less than currently anticipated, then meeting the industry’s stated production targets will require drilling more wells, with a corresponding increase in the FFC energy use and emissions per unit of gas produced. This would also lead to higher production costs and market prices; at higher prices, alternative sources such as imported LNG may be competitive. Hence, the forecast supply mix could see a shift back towards more LNG (as was being predicted by *AEO* in 2006).

3.4 Petroleum Fuels

The oil production chain is similar to natural gas, in that it consists of extraction from wells, processing, and delivery to final consumer. The major difference is that oil refining is more complex than natural gas processing, comprising a wider variety of chemical compositions on the input side and a wider range of products on the output side (Downey 2009). Oil is also transported by different modes and often across much greater distances. EIA collects extensive data on oil production, imports, and refinery processing (DOE EIA 2012j), which are also modeled in some detail in NEMS. For our analysis of FFC multipliers for building energy use, the petroleum fuel chain is relatively insignificant, as petroleum-based fuels comprise a small proportion of total electricity production and total building energy use. Diesel and fuel oil are used in coal mining and petroleum production, but the FFC impacts related to that energy use are a second-order effect. Fuel cycle studies on transportation, for which petroleum-based fuels are the primary energy source, provide detailed descriptions of the petroleum fuel chain (Brinkman et al. 2005; Palou-Rivera and Wang 2010; Bredeson et al. 2010). For this analysis we use a simplified approach based on *AEO* projections and parameters developed in other studies.

Electricity, natural gas, and petroleum use for oil extraction are taken from the GREET model documentation (Brinkman et al. 2005; Burnham, Wang, and Wu 2006; Burnham et al. 2011). Extraction energy use and emissions depend on production category, with unconventional (tar sands or shale oil) being more energy intensive and leading to larger fugitive emissions. Analysis of Canadian tar sands suggests fugitive CO_2 emissions are about 30% greater than for conventional oil (Brandt 2011). Emissions of CH_4, including fugitive emissions for different production categories, are also taken from the GREET model documentation (Burnham et al. 2011).

Estimates of energy use for refinery operations are derived from *AEO* forecasts of refinery electricity, natural gas, and petroleum use per barrel of crude oil input. Refinery energy use is allocated to diesel and fuel oil based on the energy content of these fuels relative to total refinery output. This simplified approach misses some of the nuances associated with refinery processes (Bredeson et al. 2010), but given the other sources of uncertainty in the FFC analysis, a more complicated allocation model would not improve the overall precision of the calculation. The energy use for transportation of oil products to the final consumer is relatively small (Brinkman et al. 2005) and is also neglected here.

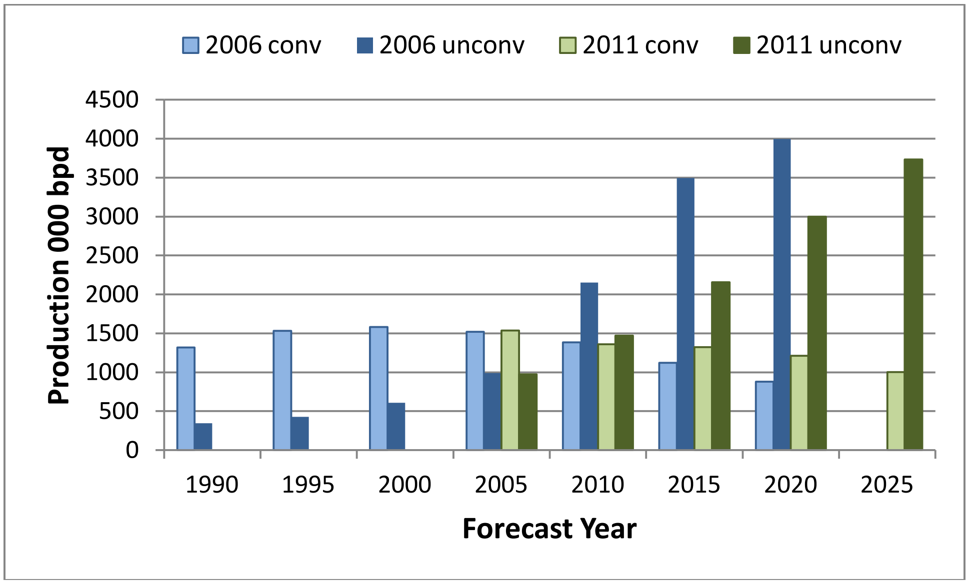
The *AEO* does not provide a breakdown of oil supply by production type. To estimate the fraction of total production from tar sands or shale oil, we assume that oil supply from these sources is 5% of total U.S. supply in 2009 and that supply *growth* for production in the United States, Canada, and Latin America comes exclusively from these sources. This is consistent with the fact that conventional sources in these regions are generally in decline (CAPP 2011; DOE EIA 2012j). With these assumptions, the *AEO* projections imply that the unconventional market share in the United States is 12% in 2015, grows to a maximum of 16% in 2022, and declines slowly to 13% in 2035.

As may be expected, projections of supply growth from unconventional sources are volatile. This is illustrated in Figure 6, which shows the Canadian Association of Petroleum Producers supply forecasts that were published in 2006 and in 2011 (CAPP 2011). The 2006 forecast over-estimated 2010 tar sands production by about 30%. This forecast also over-estimated the rate of decline of conventional oil. Comparison of *AEO 2011* to *AEO 2012* shows that the predicted U.S. domestic production in 2035 is revised upward by about 10% in *AEO 2012* compared to *AEO 2011*.

3.4.1 Issues for Further Study

As is true for natural gas, the actual energy and emissions intensity of unconventional oil production remain highly uncertain, and the water resource and other environmental impacts may be under-estimated (A. Brandt 2011; Kelly et al. 2009; Griffiths, Taylor, and Woynillowicz 2006). The current estimates of energy and emissions intensity should be considered a lower bound. As was noted for natural gas, coping with the environmental consequences of producing liquid petroleum fuels from tar sands is likely to raise both the cost and energy intensity of production, which in turn will impact the forecast supply mix.

Figure 6 Forecasts of Canadian oil production published in 2006 and 2011



3.5 Nuclear Fuel

Production of fuel for nuclear power comprises the mining and milling of uranium ore, conversion and enrichment, and fabrication of fuel rods or pellets. This analysis uses the description of the nuclear fuel cycle published in Wu et al. (Wu et al. 2006), which provides energy use per gram of Uranium-235 by fuel type and production stage. Mining and milling use diesel, gasoline, natural gas, and electricity, and further processing uses primarily electricity and natural gas. The full nuclear fuel cycle should also include storage and ultimate disposal of spent fuel; however, those aspects of the problem cannot yet be full described. These assumptions are also used in the GREET model, so our estimate of the energy multiplier for nuclear fuel is essentially the same as the preliminary estimate calculated using GREET (DOE EERE 2010). There are no site emissions associated with use of nuclear fuel; all the emissions arise from the upstream use of energy.

4. Full-Fuel-Cycle Multiplier

4.1 Calculation of the Multipliers

The analyses of Section 3 provide estimates of the time-dependent fuel production energy use parameters a_x, b_y, and c_{xy} and the emissions factors $z_x(s)$ for each pollutant type. Time-dependent values for the average heat content of different fuels (q_x) are published in *AEO*. With this information, calculation of the energy and emissions parameters using the methodology outlined in Section 2 is straightforward. Table 11 provides a summary of the physical parameters and multiplier matrix **M** in physical units for coal, petroleum, and natural gas, based on inputs from *AEO 2012.* The units for coal are short tons (T), for natural gas thousand standard cubic feet

(Mcf), and for oil barrels (bbl). The table also shows a non-dimensional version of the matrix **M,** denoted **M'**, which is obtained by setting $M'_{xy} = q_x M_{xy}/q_y$. The energy multipliers are obtained by summing the columns of **M'**. The electricity multiplier is a weighted average of the fuel-specific energy multipliers, with the weights determined by the burn rates a_x. All the energy multipliers are listed in Table 12 for the years 2010, 2020, and 2030.

Table 11 Summary of physical parameters and energy multipliers for 2010.

$a_x \cdot b_y$								
x\y	coal T	petroleum bbl	ng Mcf		**M_{xy}**	coal T	petroleum bbl	ng Mcf
coal T	0.0019	0.0013	0		coal ton	1.0033	0.0014	0
pet bbl	0.00013	0.0001	0		pet bbl	0.064	1.069	0
ng Mcf	0.014	0.0099	0		ng Mcf	0.036	0.33	1.107
C_{xy}								
x\y	coal ton	petroleum bbl	ng Mcf		**M'_{xy}**	coal	petroleum	ng
coal T	0.0013	0	0		coal	1.0033	0.0048	0
pet bbl	0.060	0.064	0		pet	0.019	1.069	0
ng Mcf	0	0.27	0.097		ng	0.0019	0.058	1.107

Table 12 Energy multipliers for 2010, 2020 and 2030

μ	**Coal**	**Petroleum**	**Natural gas**	**Electricity**
2010	1.025	1.134	1.107	1.036
2020	1.026	1.145	1.103	1.035
2030	1.026	1.161	1.099	1.035

Our estimates of the baseline emissions and fuel cycle multipliers are provided in Table 13. For most pollutants the increase of FFC emissions over emissions calculated for site energy are comparable in magnitude to the energy multipliers, *i.e.,* in the range of 2%-13%. There are two reasons for this. First, all the information that is specific to the fuel cycle itself is incorporated into the multiplier matrix **M**, which is used for both the FFC energy and emissions calculations. Second, as will be discussed further below, our definition of the emissions intensity factors z_x combines both combustion and fugitive emissions into a single parameter. Hence, the values tabulated under the baseline heading include the fugitive emissions generated from the production of the fuel that is consumed on-site. The FFC contribution tabulates the additional combustion and fugitive emissions that occur due to the additional energy expended in the fuel chain. The contribution of fugitive emissions to the baseline is small relative to the site combustion emissions, and conceptually one could argue that all fugitive emissions should be counted as "upstream". However, using a single emissions intensity streamlines the calculations and simplifies the reporting. Ultimately, the relevant physical quantity is the total FFC value, irrespective of how it is broken down into components.

Table 13 FFC emissions factors for 2020 (only non-zero values are shown)

Category	Species	Fuel	Value (g/Unit)	Unit
site combustion	CH4	l	210	ton
FFC upstream	CH4	l	2,790	ton
site combustion	CH4	n	1.02	mcf
FFC upstream	CH4	n	617	mcf
site combustion	CH4	p	17.5	bbl
FFC upstream	CH4	p	674	bbl
FFC upstream	CH4	u	203	g
site combustion	CO2	l	1,825	ton
FFC upstream	CO2	l	35.1	ton
site combustion	CO2	n	54.2	mcf
FFC upstream	CO2	n	6.79	mcf
site combustion	CO2	p	431	bbl
FFC upstream	CO2	p	62.2	bbl
FFC upstream	CO2	u	50.8	g
site combustion	N2O	l	30.5	ton
FFC upstream	N2O	l	0.718	ton
site combustion	N2O	n	0.102	mcf
FFC upstream	N2O	n	0.0105	mcf
site combustion	N2O	p	3.50	bbl
FFC upstream	N2O	p	0.656	bbl
FFC upstream	N2O	u	0.697	g
site combustion	NOx	l	1636	ton
FFC upstream	NOx	l	440	ton
site combustion	NOx	n	29.2	mcf
FFC upstream	NOx	n	95.4	mcf
site combustion	NOx	p	166	bbl
FFC upstream	NOx	p	830	bbl
FFC upstream	NOx	u	425	g
site combustion	SO2	l	1,447	ton
FFC upstream	SO2	l	11.4	ton
FFC upstream	SO2	n	0.0286	mcf
site combustion	SO2	p	402	bbl
FFC upstream	SO2	p	16.6	bbl
FFC upstream	SO2	u	26.3	g
site combustion	Hg	l	0.0069	ton
FFC upstream	Hg	l	2.05E-05	ton
FFC upstream	Hg	p	9E-06	bbl
FFC upstream	Hg	u	9E-05	g

4.2 Comparison with GREET Model Output

DOE has published a set of prepared preliminary FFC energy and emissions factors computed using the GREET model (DOE EERE 2010), which are compared to the values calculated in this report in Table 14 (multipliers for electricity were not published). Overall there is reasonably good agreement. The values for coal calculated in this report are slightly higher, presumably due to the fact that GREET assumes a lower material loss rate in processing. The numbers calculated in this analysis for petroleum are very close to the GREET values for 2010 and differ for 2030. This is likely due to different estimates of the fraction of supply coming from unconventional sources in future years. The natural gas values calculated in this analysis are somewhat higher. The natural gas calculation is very simple, relying only on the lease and plant and pipeline fuel use numbers published in *AEO*. Hence, any differences with the GREET model values must result from different estimates of natural gas use in the field. It is not clear which estimate should be treated as more precise, as there are uncertainties and data limitations in both cases.

Table 14 Comparison with GREET multipliers for 2010 data.

	This Analysis			**DOE/GREET Preliminary**		
μ	Coal	Petroleum	Natural gas	Coal	Petroleum	Natural gas
2010	1.025	1.135	1.107	1.021	1.134	1.073
2030	1.026	1.163	1.099	1.021	1.147	1.073
M'_{xy}	**This Analysis**			**DOE/GREET Preliminary**		
(2010)	Coal	Petroleum	Natural gas	Coal	Petroleum	Natural gas
Coal	1.0033	0.0048	0	1.004	0.020	0.002
Petroleum	0.019	1.069	0	0.013	1.050	0.004
Natural gas	0.0019	0.058	1.107	0.002	0.056	1.065

The components of the multiplier matrix **M’,** which have been non-dimensionalized by the fuel heat content, are directly comparable to the energy conversion factors published in Table 2 of (DOE EERE 2010). The comparison in Table 14 shows that the allocation of energy use to different fuel types differs somewhat between the two approaches. This is not surprising, as there is large variability in production methods and it is difficult to determine the precise breakdowns from existing data. It's also important to note that *AEO* and GREET are designed for different purposes and so will have correspondingly different approaches to estimating the parameters that quantify fuel use. GREET is used primarily to compare FFC energy across a wide variety of energy pathways, and so the model defines a detailed representation of a typical or representative example for each pathway. In contrast, the NEMS/AEO model is used to provide a projection of total energy production and consumption across all sectors and end-uses, so the parameters used should be representative of industry-wide average conditions.

4.3 Using the Full-Fuel-Cycle Multipliers and Emissions Factors

The FFC energy multipliers are dimensionless numbers that should be applied to site consumption of fuel measured in energy units. For primary fuels such as coal, fuel oil, or natural gas, if site energy savings are equal to Δ_x (in physical units for fuel type *x*), then the energy content in the fuel is $q_x\Delta_x$, and the FFC energy savings are equal to $\mu_x q_x \Delta_x$ (q_x is the heat or energy content of the fuel). The product $\mu_x\Delta_x$ has no meaning.

For electricity, before the multiplier can be applied, the energy content of the electricity must be defined in terms of the energy content of the fuels used to generate it. This corresponds to the familiar process of converting site electricity to source or primary energy. Information about the quantity of fuel needed to produce a unit of grid electricity is contained in the burn rate coefficients a_x. Any losses in the transmission and distribution system must also be accounted for in the site-to-source conversion. For a quantity of site electricity savings Δ_{kWh} in units of kWh, the steps are:

1. apply the transmission and distribution loss factor l_{TD};
2. convert from kWh to power plant energy units, which in our notation is equal to multiplication by $\mathbf{q} \cdot \mathbf{a}$ (units MBtu/kWh); and
3. Apply the multiplier μ_{elec}.

Hence, primary or power plant energy is equal to $\boldsymbol{q} \cdot \boldsymbol{a}\, l_{TD} \Delta_{kWh}$, and FFC energy is equal to μ_{elec} times the primary energy.

The multiplier is just one way of expressing the information that is contained in the FFC multiplier matrix **M** (Coughlin 2012). In some applications it may be simpler to work with this matrix directly. For example, to determine the emissions from combustion of a quantity Δ_x of fuel x, from equation (3) the total FFC emissions are given by

$$(\textstyle\sum_y z_y M_{yx}) \Delta_x ,$$

where $z_y(s)$ is the emissions intensity of pollutant s for fuel y. The total emissions can be separated into site and upstream components as in equation (4).

5. Discussion

In this study we have used the methodology defined in (Coughlin 2012) to calculate FFC energy and emissions multipliers appropriate for calculation of FFC energy use in buildings and industry. The multipliers are calculated as a function of time using projections from the *AEO* and compared to output from the GREET model.

Most energy policy programs have impacts that occur over an extended period of time, so correct evaluation of the total energy savings requires projections of how the fuel production chain will evolve in the future. Projections of future energy supply can be quite volatile, as has been illustrated here through comparison of the forecasts of unconventional oil and gas production published in 2006 versus 2011. Even for editions of the *AEO* separated by only one year, the expected output from different supply sources can shift by up to 10%. This volatility is not a question of modeling precision *per se*, it results from the decision by the forecaster to extrapolate current trends in specific ways. Any projection into the future will have this problem; the practical consequence is to set an upper bound on the precision of the FFC factors, which in turn defines the level of precision in the input data that is practically meaningful. We estimate the level of precision to be on the order of 10%.

There are a number of open questions about fossil fuel production chains that are likely to have an impact larger than 10%. As more data become available, the FFC calculations will be updated accordingly. The most significant issues are associated with unconventional production of oil and gas; current estimates of the energy and emissions intensity of unconventional production are at best a lower bound, and current projections of future supply from these sources are likely to err on the high side. Raising the intensity factors would increase the multipliers, while lowering the proportion of total fuel supply coming from unconventional sources would lower them, so it is difficult to predict what the net effect on the multiplier values would be. The projected market share of renewable sources in electricity generation can also have a significant impact on the calculated multipliers. Wind penetration in particular is increasing rapidly, and current estimates of future penetration may be too low. As renewable shares increase, the average quantity of physical fuel needed per unit of energy service provided to the economy as a whole decreases, which would tend to lower the value of the multipliers.

These uncertainties highlight the advantage of using a public, well-supported forecast model such as NEMS/AEO to develop inputs to the FFC multiplier estimates. The EIA updates the data input to the *AEO* each year and devotes considerable resources to modeling the oil, gas, and power production sectors. The NEMS model also takes into account economic trends that impact the demand for fuel and the supply mix. EIA is responsive to public comment, so as new data and analyses become available we expect them to be reflected in changes to the *AEO* projections of fuel supply and energy sector energy use. On the other hand, the *AEO* output is highly aggregated, so it will be useful in future refinements of this analysis to supplement *AEO* data with more detail on energy and emissions at different stages of the production chain and with analysis of variability across different production methods.

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